TETRAGON ENERGY

PROSPECTUS

TETRAGON ENERGY LIMITED

ACN 684 303 660

For an offer of 20,000,000 Shares at an issue price of $0.20 per Share to raise $4,000,000 (Public Offer).

The Prospectus also contains the Secondary Offers which are detailed in Section 4.7.

The Offers are conditional upon satisfaction of the Conditions, which are detailed further in Section 4.8. No Securities will be issued pursuant to this Prospectus until those Conditions are met.

IMPORTANT NOTICE

This document is important and should be read in its entirety. If, after reading this Prospectus you have any questions about the Securities being offered under this Prospectus or any other matter, then you should consult your professional advisers without delay.

The Securities offered by this Prospectus should be considered as highly speculative.

LEAD MANAGER

powerHouse

LEGAL ADVISOR

STEINEPREIS PAGANIN

IMPORTANT NOTICE

This Prospectus is dated 15 May 2026 and was lodged with the ASIC on that date. The ASIC, the ASX and their respective officers take no responsibility for the contents of this Prospectus or the merits of the investment to which this Prospectus relates.

No Securities will be issued on the basis of this Prospectus later than 13 months after the date of this Prospectus.

No person is authorised to give information or to make any representation in connection with this Prospectus, which is not contained in this Prospectus. Any information or representation not so contained may not be relied on as having been authorised by the Company in connection with this Prospectus.

It is important that you read this Prospectus in its entirety and seek professional advice where necessary. The Securities offered under this Prospectus should be considered as highly speculative.

Exposure Period

This Prospectus will be circulated during the Exposure Period. The purpose of the Exposure Period is to enable this Prospectus to be examined by market participants prior to the raising of funds. You should be aware that this examination may result in the identification of deficiencies in this Prospectus and, in those circumstances, any application that has been received may need to be dealt with in accordance with section 724 of the Corporations Act. Applications for Securities under this Prospectus will not be accepted by the Company until after the expiry of the Exposure Period. No preference will be conferred on applications lodged prior to the expiry of the Exposure Period.

No offering where offering would be illegal

The distribution of this Prospectus in jurisdictions outside Australia may be restricted by law and persons who come into possession of this Prospectus should observe any of these restrictions, including those set out below. Failure to comply with these restrictions may violate securities laws. Applicants who are resident in countries other than Australia should consult their professional advisers as to whether any governmental or other consents are required or whether any other formalities need to be considered and followed.

This Prospectus does not constitute an offer or invitation to apply for Securities in any place in which, or to any person to whom, it would not be lawful to make such an offer or invitation. It is important that investors read this Prospectus in its entirety and seek professional advice where necessary.

No action or formality has been taken to register or qualify the Securities or the offer, or to otherwise permit a public offering of the Securities in any jurisdiction outside Australia.

This Prospectus has been prepared for publication in Australia and may not be distributed outside Australia except to Institutional Investors in Singapore, Hong Kong and the Philippines.

Hong Kong

WARNING: This document has not been, and will not be, registered as a prospectus under the Companies (Winding Up and Miscellaneous Provisions) Ordinance (Cap. 32) of Hong Kong, nor has it been authorised by the Securities and Futures Commission in Hong Kong pursuant to the Securities and Futures Ordinance (Cap. 571) of the Laws of Hong Kong (the "SFO"). Accordingly, this document may not be distributed, and the Shares may not be offered or sold, in Hong Kong other than to "professional investors" (as defined in the SFO and any rules made under that ordinance).

No advertisement, invitation or document relating to the Shares has been or will be issued, or has been or will be in the possession of any person for the purpose of issue, in Hong Kong or elsewhere that is directed at, or the contents of which are likely to be accessed or read by, the public of Hong Kong (except if permitted to do so under the securities laws of Hong Kong) other than with respect to Shares that are or are intended to be disposed of only to persons outside Hong Kong or only to professional investors. No person allotted Shares may sell, or offer to sell, such securities in circumstances that amount to an offer to the public in Hong Kong within six months following the date of issue of such securities.

The contents of this document have not been reviewed by any Hong Kong regulatory authority. You are advised to exercise caution in relation to the offer. If you are in doubt about any contents of this document, you should obtain independent professional advice.

Singapore

This document and any other materials relating to the Shares have not been, and will not be, lodged or registered as a prospectus in Singapore with the Monetary Authority of Singapore. Accordingly, this document and any other document or materials in connection with the offer or sale, or invitation for subscription or purchase, of Shares, may not be issued, circulated or distributed, nor may the Shares be offered or sold, or be made the subject of an invitation for subscription or purchase, whether directly or indirectly, to persons in Singapore except pursuant to and in accordance with exemptions in Subdivision (4) Division 1, Part 13 of the Securities and Futures Act 2001 of Singapore (the **SFA**) or another exemption under the SFA.

This document has been given to you on the basis that you are an "institutional investor" or an "accredited investor" (as such terms are defined in the SFA). If you are not such an investor, please return this document immediately. You may not forward or circulate this document to any other person in Singapore.

Any offer is not made to you with a view to the Shares being subsequently offered for sale to any other party in Singapore. On-sale restrictions in Singapore may be applicable to investors who acquire Shares. As such, investors are advised to acquaint themselves with the SFA provisions relating to resale restrictions in Singapore and comply accordingly.

Philippines

THE SECURITIES BEING OFFERED OR SOLD HAVE NOT BEEN REGISTERED WITH THE PHILIPPINE SECURITIES AND EXCHANGE COMMISSION UNDER THE PHILIPPINE SECURITIES REGULATION CODE (THE **CODE**). ANY FUTURE OFFER OR SALE THEREOF IS SUBJECT TO REGISTRATION REQUIREMENTS UNDER THE CODE UNLESS SUCH OFFER OR SALE QUALIFIES AS AN EXEMPT TRANSACTION.

The Shares are being offered and sold to qualified buyers in an exempt transaction under Section 10.1(l) of the Code. The Company has not sought confirmation, and the SEC has not confirmed, whether the offer of Shares qualifies as an exempt transaction under the Code.

Information about the Company is available in this Australian prospectus for its initial public offer in Australia with a listing on the Australian Securities Exchange.

US securities law matters

This Prospectus does not constitute an offer to sell, or a solicitation of an offer to buy, securities in the United States. In particular, the Securities have not been, and will not be, registered under the United States Securities Act of 1933, as amended (the **US Securities Act**), and may not be offered or sold in the United States except in transactions exempt from, or not subject to, the registration requirements of the US Securities Act.

Electronic Prospectus

A copy of this Prospectus can be downloaded from the website of the Company at **www.tetragonenergy.com.au**. If you are accessing the electronic version of this Prospectus for the purpose of making an investment in the Company, you must be a resident of Australia and must only access this Prospectus from within Australia.

The Corporations Act prohibits any person passing onto another person an Application Form unless it is accompanied by the complete and unaltered version of this Prospectus. You may obtain a hard copy of this Prospectus free of charge by contacting the Company by phone on + 61 (8) 9219 7111 during office hours or by emailing the Company at **www.tetragonenergy.com.au**.

The Company reserves the right not to accept an Application Form from a person if it has reason to believe that when that person was given access to the electronic Application Form, it was not provided together with the electronic Prospectus and any relevant supplementary or replacement prospectus or any of those documents were incomplete or altered.

Company Website

No document or other information available on the Company's website is incorporated into this Prospectus by reference.

No cooling-off rights

Cooling-off rights do not apply to an investment in Securities issued under this Prospectus. This means that, in most circumstances, you cannot withdraw your application once it has been accepted.

No Investment Advice

The information contained in this Prospectus is not financial product advice or investment advice and does not take into account your financial or investment objectives, financial situation or particular needs (including financial or taxation issues). You should seek professional advice from your accountant, financial adviser, stockbroker, lawyer or other professional adviser before deciding to subscribe for Securities under this Prospectus to determine whether an investment in the Company meets your objectives, financial situation and needs.

Risks

You should read this document in its entirety and, if in any doubt, consult your professional advisers before deciding whether to apply for Securities. There are risks associated with an investment in the Company. The Securities offered under this Prospectus carry no guarantee with respect to return on capital investment, payment of dividends or the future value of the Securities. Refer to Section D of the Investment Overview as well as Section 7 for details relating to some of the key risk factors that should be considered by prospective investors. There may be risk factors in addition to these that should be considered in light of your personal circumstances.

Forward-looking statements

This Prospectus contains forward-looking statements which are identified by words such as 'may', 'could', 'believes', 'estimates', 'targets', 'expects', or 'intends' and other similar words that involve risks and uncertainties.

These statements are based on an assessment of present economic and operating conditions, and on a number of assumptions regarding future events and actions that, as at the date of this Prospectus, are expected to take place.

Such forward-looking statements are not guarantees of future performance and involve known and unknown risks, uncertainties, assumptions and other important factors, many of which are beyond the control of the Company, the Directors and the Company's management.

The Company cannot and does not give any assurance that the results, performance or achievements expressed or implied by the forward-looking statements contained in this Prospectus will actually occur and investors are cautioned not to place undue reliance on these forward-looking statements.

The Company has no intention to update or revise forward-looking statements, or to publish prospective financial information in the future, regardless of whether new information, future events or any other factors affect the information contained in this Prospectus, except where required by law.

These forward-looking statements are subject to various risk factors that could cause the Company's performance and actual results to differ materially from the results expressed or anticipated in these statements. These risk factors are set out in Section 7.

Financial Forecasts

The Directors have considered the matters set out in ASIC Regulatory Guide 170 and believe that they do not have a reasonable basis to forecast future earnings on the basis that the operations of the Company are inherently uncertain. Accordingly, any forecast or projection information would contain such a broad range of potential outcomes and possibilities that it is not possible to prepare a reliable best estimate forecast or projection.

Qualified Reserves and Resource Evaluator's statement

The information in the Company and Projects Overview, included at Section 5 including the maps and diagrams and the Independent Technical Specialist's Report, included at Annexure A of the Prospectus, which relate to the resources have been prepared according to the classifications and definitions of the Petroleum Resources Management System, sponsored by the Society of Petroleum Engineers Oil and Gas Reserves Committee. The information in this Prospectus (including Annexure A) which relates to resources is based on, and fairly and accurately represents, in the form and context in which it appears, information and supporting documentation prepared by Mr Simon McDonald, a Principal Strategic Advisor of ERCE Australia Pty Ltd (trading as Sproule ERCE), an independent petroleum consultancy, who is not an employee of Tetragon Energy Limited or a related party, and who is a Qualified Petroleum Reserves and Resources Evaluator as defined in the Listing Rules. Mr Simon McDonald is a member of the Society of Petroleum Engineers (SPE) and the Society of Petroleum Evaluation Engineers (SPEE). Mr McDonald consents to the inclusion of the information in these Sections of the Prospectus and Annexure A in the form and context in which it appears.

Continuous disclosure obligations

Following Admission, the Company will be a "disclosing entity" (as defined in section 111AC of the Corporations Act) and, as such, will be subject to regular reporting and disclosure obligations. Specifically, like all listed companies, the Company will be required to continuously disclose any information it has to the market which a reasonable person would expect to have a material effect on the price or the value of the Securities.

Price sensitive information will be publicly released through ASX before it is disclosed to Shareholders and market participants. Distribution of other information to Shareholders and market participants will also be managed through disclosure to the ASX. In addition, the Company will post this information on its website after the ASX confirms an announcement has been made, with the aim of making the information readily accessible to the widest audience.

Clearing House Electronic Sub-Register System (CHESS) and Issuer Sponsorship

The Company will apply to participate in CHESS, for those investors who have, or wish to have, a sponsoring stockbroker. Investors who do not wish to participate through CHESS will be issuer sponsored by the Company.

Electronic sub-registers mean that the Company will not be issuing certificates to investors. Instead, investors will be provided with statements (similar to a bank account statement) that set out the number of Securities issued to them under this Prospectus. The notice will also advise holders of their Holder Identification Number or Security Holder Reference Number and explain, for future reference, the sale and purchase procedures under CHESS and issuer sponsorship.

Electronic sub-registers also mean ownership of securities can be transferred without having to rely upon paper documentation. Further monthly statements will be provided to holders if there have been any changes in their security holding in the Company during the preceding month.

Photographs and Diagrams

Photographs used in this Prospectus which do not have descriptions are for illustration only and should not be interpreted to mean that any person shown endorses this Prospectus or its contents or that the assets shown in them are owned by the Company. Diagrams used in this Prospectus are illustrative only and may not be drawn to scale.

Definitions and Time

Unless the contrary intention appears or the context otherwise requires, words and phrases contained in this Prospectus have the same meaning and interpretation as given in the Corporations Act and capitalised terms have the meaning given in the Glossary in Section 12. All references to time in this Prospectus are references to Australian Western Standard Time.

Privacy statement

If you complete an Application Form, you will be providing personal information to the Company. The Company collects, holds and will use that information to assess your application, service your needs as a Shareholder and to facilitate distribution payments and corporate communications to you as a Shareholder.

The information may also be used from time to time and disclosed to persons inspecting the register, including bidders for your Securities in the context of takeovers, regulatory bodies including the Australian Taxation Office, authorised securities brokers, print service providers, mail houses and the share registry.

You can access, correct and update the personal information that the Company holds about you. If you wish to do so, please contact the share registry at the relevant contact details set out in this Prospectus.

Collection, maintenance and disclosure of certain personal information is governed by legislation including the *Privacy Act 1988* (Cth) (as amended), the Corporations Act and certain rules such as the ASX Settlement Operating Rules. You should note that if you do not provide the information required on your application for Securities under this Prospectus, the Company may not be able to accept or process your application.

Enquiries

If you are unclear in relation to the matters raised in this Prospectus or are in doubt as to how to deal with it, you should seek professional advice from your accountant, financial adviser, stockbroker, lawyer or other professional adviser without delay. Should you have any questions in relation to the Offers or how to accept the Offers please contact the Company Secretary on + 61 (8) 9219 7111.

CORPORATE DIRECTORY

Directors

Greg Hancock
Non-Executive Chairman

Conrad Todd
Managing Director

Mike Collins
Non-executive Director

Joint Company Secretaries

Geraldine Holland

Henko Vos

Proposed ASX Code

TET

Registered Office

Suite 2
100 Havelock Street
WEST PERTH WA 6005

Telephone: + 61 (8) 9219 7111

Email: **info@tetragonenergy.com.au**
Website: **www.tetragonenergy.com.au**

Share Registry*

Automic Group

Telephone (within Australia): 1300 288 664
Telephone (International): +61 2 9698 5414

Legal advisers

Steinepreis Paganin
Level 14, QV1 Building
250 St Georges Terrace
PERTH WA 6000

Investigating Accountant & Auditor

HLB Mann Judd
Level 4, 130 Stirling Street
PERTH WA 6000

Title Report Legal Advisers

Parada Rivera Evardone & Salalima
Attorneys-at-Law
Unit 1802 - 18th Floor, Tektite Tower West,
Exchange Rd, Ortigas Center, Pasig, 1605
Kalakhang Maynila, Philippines

Independent Technical Specialist

ERCE Australia Pty Ltd
2A/83 Havelock Street
West Perth WA 6005

Lead Manager

Powerhouse Advisory Australia Pty Ltd
Suite 201, 117-119 McLachlan Street
Fortitude Valley QLD 4006

Corporate Advisor

Salient Corporate Pty Ltd
6/589 Stirling Highway
Cottesloe WA 6011

**This entity is included for information purposes only. It has not been involved in the preparation of this Prospectus.*

TABLE OF CONTENTS

1. LETTER FROM CHAIR 1
2. KEY OFFER INFORMATION 2
3. INVESTMENT OVERVIEW 4
4. DETAILS OF THE OFFERS 17
5. COMPANY AND PROJECTS OVERVIEW 22
6. FINANCIAL INFORMATION 33
7. RISK FACTORS 49
8. BOARD AND KEY MANAGEMENT, CORPORATE GOVERNANCE AND ESG 62
9. MATERIAL CONTRACTS 70
10. ADDITIONAL INFORMATION 75
11. DIRECTORS' AUTHORISATION 90
12. GLOSSARY 91

ANNEXURE A – INDEPENDENT TECHNICAL SPECIALIST'S REPORT 93

ANNEXURE B – SOLICITOR'S REPORT ON TITLE 189

ANNEXURE C – INDEPENDENT LIMITED ASSURANCE REPORT 1

1. LETTER FROM CHAIR

Dear Investor

On behalf of the directors of Tetragon Energy Limited (**Tetragon** or the **Company**), I am pleased to offer you the opportunity to become a Shareholder of the Company.

Tetragon has been established following a demerger from Triangle Energy (Global) Limited (ASX: TEG) (**Triangle**), having been established with a key focus to unlock significant value from under-explored and highly prospective oil and gas exploration and development projects in South-East Asia.

The Company holds three recently awarded petroleum exploration blocks; SC-82 (onshore Luzon and 100% interest) and SC-80 and SC-81 (offshore Sulu Sea and a 37.5% interest) located in the Philippines (the **Projects**). The Philippines provides excellent operating and fiscal terms for exploration and development companies.

Our strategy is underpinned by the following core pillars:

(a) high-impact exploration to maximise Shareholder value and deliver benefits for all stakeholders;

(b) form strategic partnerships focused on securing upstream operating and equity partners to advance all assets and opportunities; and

(c) negotiating commercial agreements for access to existing infrastructure to advance development and production opportunities.

The Company's board and management are highly credentialed and bring together decades of industry experience, particularly in the Southeast Asian Oil and Gas sector.

The Offer

This Prospectus is seeking to raise $4,000,000 via the issue of Shares at an issue price of $0.20 per Share under the Public Offer.

The purpose of the Public Offer is to provide funds to implement the Company's business strategies (explained in Section 5).

In addition, subject to completion of the Public Offer and listing on the ASX, the Company presently intends on undertaking a pro-rata offer of loyalty Options to shareholders registered on a record date proposed to be on or about 3 months from the date of listing. It is expected that these Options will be issued on a 1 for 2 basis, with an exercise price of $0.40 and expiring approximately two years from the date of issue. Notwithstanding the above, the Board will retain full discretion as to whether to proceed with, or to vary, the terms and timing of any such offer.

This Prospectus is issued for the purpose of supporting an application to list the Company on ASX. This Prospectus contains detailed information about the Company, its business and the Public Offer, as well as the risks of investing in the Company, and I encourage you to read it carefully. The Securities offered by this Prospectus should be considered highly speculative.

I look forward to you joining us as a Shareholder and sharing in what we believe are exciting and prospective times ahead for the Company. Before you make your investment decision, I urge you to read this Prospectus in its entirety and seek professional advice if required.

Yours sincerely,

Greg Hancock
Non-Executive Chairman
TETRAGON ENERGY LIMITED

2. KEY OFFER INFORMATION

INDICATIVE TIMETABLE[1]

Lodgement of Prospectus with the ASIC	Friday, 15 May 2026
Exposure Period begins	Friday, 15 May 2026
Opening Date	Monday, 25 May 2026
Closing Date	5:00pm (WST) on Friday, 12 June 2026
Issue of Securities under the Offers[2]	Wednesday, 17 June 2026
Despatch of holding statements	Friday, 19 June 2026
Expected date for quotation on ASX	Friday, 26 June 2026

1. The above dates are indicative only and may change without notice. Unless otherwise indicated, all times given are in WST. The Exposure Period may be extended by the ASIC by not more than 7 days pursuant to section 727(3) of the Corporations Act. The Company reserves the right to extend the Closing Date or close the Public Offer early without prior notice. The Company also reserves the right not to proceed with the Public Offer at any time before the issue of Shares to applicants.
2. If the Public Offer is cancelled or withdrawn before completion of the Public Offer, then all application monies will be refunded in full (without interest) as soon as possible in accordance with the requirements of the Corporations Act. Investors are encouraged to submit their applications as soon as possible after the Public Offer opens.

KEY STATISTICS OF THE OFFERS

Public Offer Price per Share	$0.20
Shares currently on issue	19,700,408
Shares to be issued under the Public Offer[1]	20,000,000
Existing cash reserves	$1,500,000
Amount to be raised under the Public Offer	$4,000,000
Shares on issue at Admission (undiluted)[2]	**39,700,408**
Market Capitalisation at Admission (undiluted)[3]	**$7,940,082**
Options currently on issue	-
Performance Rights on issue	-
Options to be issued under the Lead Manager Offer[4]	2,000,000
Options to be issued under the Advisor Offer[4]	1,250,000
Performance Rights to be issued under the Management Offer[4]	3,900,000
Shares on issue at Admission (fully diluted)[5]	**46,850,408**
Market Capitalisation at Admission (fully diluted)[3]	**$9,370,082**

Notes:

1. Assuming the Minimum Subscription of $4,000,000 is achieved under the Public Offer.
2. Certain Securities on issue post-listing may be subject to ASX-imposed escrow. Refer to Section 5.13 for details with respect to the likely escrow position.
3. Assuming a Share price of $0.20, however the Company notes that the Shares may trade above or below this price post Admission.
4. Refer to Section 4.7 for the terms of the Lead Manager Offer, the Advisor Offer and the Management Offer.
5. Excludes the potential offer of loyalty Options within three months of Admission. See Section 5.11 for further details.

HOW TO INVEST

Applications for Shares can only be made by completing and lodging an Application Form. Instructions on how to apply for Shares are set out in Section 4.9 and on the Application Form.

3. INVESTMENT OVERVIEW

This Section is a summary only and is not intended to provide full information for investors intending to apply for Shares offered pursuant to this Prospectus. This Prospectus should be read and considered in its entirety.

Item	Summary	Further information
A. Company		
Who is the issuer of this Prospectus?	Tetragon Energy Limited (ACN 684 303 660) (**Tetragon** or the **Company**).	Section 5.1
Who is the Company?	The Company is an Australian unlisted public company, incorporated on 6 February 2025. Since incorporation, the Company has focused on oil and gas exploration and development activities in the Philippines.	Section 5.1
What is the Company's interest in the Projects?	The Company holds the interests in the following projects: (a) 100% interest in SC-82, an onshore petroleum service contract in the Cagayan Basin on the island of Luzon, Philippines; and (b) 37.5% interest in each of SC-80 and SC-81, offshore petroleum service contracts in the Sandakan Basin, Sulu Sea, Philippines, (together, the **Projects**).	Section 5.3, Annexure A and Annexure B
B. Business Model		
What is the Company's business model?	Following completion of the Public Offer, the Company's proposed business model will be to focus on exploration and development of petroleum resource opportunities, and specifically exploration and development of the Projects, initially as per the Company's proposed exploration programs. The Company proposes to fund its exploration activities over the first two years following listing as outlined in the table at Section 5.8. A detailed explanation of the Company's business model and strategy post-Admission is provided at Section 5.4 and a summary of the Company's proposed exploration programs is set out at Section 5.5.	Sections 5.4, 5.5 and 5.8
What are the key business objectives of the Company?	The Company's main objectives upon Admission will be to: (a) systematically explore and seek to develop each of the Projects; (b) assess new strategic acquisitions and investment opportunities that may present; (c) implement a growth strategy and actively canvass other oil and gas exploration and development opportunities which have the potential to generate growth and value for Shareholders; (d) form strategic partnerships focused on securing upstream operating and equity partners to advance the Projects; and (e) provide working capital.	Section 5.4

Item	Summary	Further information
What are the key dependencies of the Company's business model?	The key dependencies influencing the viability of the Company's business model are: (a) maintaining title to the Projects by undertaking the necessary development works; (b) the Company's ability to obtain and retain all necessary approvals (including any regulatory or third-party approvals) required to undertake its proposed work programs; (c) ability to secure Project partners including operator, joint venture partners, offtakers and infrastructure partners to enable the development and operation of the Projects; (d) successful completion of development studies, including seismic reprocessing on the Projects, resulting in increased confidence in the commercial viability of the Projects and progression towards drilling; (e) retaining and recruiting key personnel skilled in the oil and gas sector; (f) sufficient worldwide demand for LNG and local demand for gas; (g) the market price of LNG and gas supporting the Projects commercial viability; and (h) minimising environmental impacts and complying with environmental and health and safety requirements,	Section 5.9
What is the Company's growth strategy?	The Company intends to grow through systematic exploration of the Projects, forming strategic partnerships with industry operators and equity partners, and evaluating complementary oil and gas acquisition opportunities in South-East Asia.	Section 5
C. Key Advantages		
What are the key advantages of an investment in the Company?	The Directors are of the view that an investment in the Company provides the following non-exhaustive list of advantages: (a) subject to raising the Minimum Subscription, the Company will have sufficient funds to implement its exploration strategy; (b) the Company will hold a portfolio of quality assets located in the Philippines considered by the Board to be highly prospective for petroleum; and (c) a highly credible and experienced team to progress exploration and accelerate potential development of the Projects.	Section 5
D. Key Risks		
Conditional Prospectus	The Offers are conditional upon the Conditions being satisfied or waived. The Conditions are set out in Section 4.10. There is no certainty that the Conditions will be satisfied. In the event that these Conditions are not met then the listing of the Company on ASX will not proceed, and all application monies received will be returned to applicants without interest.	Sections 4.8 and 7.2

Item	Summary	Further information
Limited History	While the Company has been incorporated since 6 February 2025, during that time it has operated as a wholly owned subsidiary of Triangle. No assurance can be given that the Company will achieve commercial viability through the successful exploration of the Projects. Until the Company is able to realise value from its Projects, it is likely to incur ongoing operating losses.	Section 7.2
Development and commercialisation of the Projects	The Company's future performance is significantly dependent on achieving milestones leading to the successful development of the Projects. Oil and gas projects, which includes petroleum exploration, are subject to a range of risks and uncertainties that may affect timing, costs and ultimate viability. Development activities can be delayed or disrupted by adverse weather, equipment failure, unexpected geological conditions, labour shortages, industrial action, cost inflation and supply chain constraints. The Company must also secure and maintain a variety of government approvals before commencing or expanding operations. Even if the development and commercialisation proceed in line with expectations, there is no assurance that the Projects will be commercially viable or capable of generating positive cash flow. Delays or cost overruns may materially impact the Company's financial position and its ability to fund ongoing operations. A failure to achieve key development milestones, or to do so on schedule and within budget, may adversely affect the Company's business, prospects and the value of its Shares.	Section 7.2
Permit renewal	The Company is required to comply with a range of laws to retain the Permits comprising the Projects and periodically apply to renew them. Each Permit also has its own specific work program and expenditure requirements that the Company must satisfy. There can be no assurance that any of the Permits will be renewed (or renewed on the same terms), or that the Company will be able to continue to meet all renewal conditions, work program obligations, or expenditure requirements. If a Permit is not renewed, is renewed subject to materially more onerous conditions, or is suspended, amended or cancelled, the Company's ability to continue exploration and/or development activities on the relevant Projects may be delayed, restricted or prevented, which could have a material adverse effect on the Projects and the Company's business, financial condition and results of operations. The extension of each service contract for a further period is conditional on the Company not being in default of its exploration work and other obligations and having provided an agreed work programme and budget for the extension period. There can be no assurance that these conditions will be satisfied or that extension will be granted on the same terms.	Section 7.2
Contractual risks – Joint Operating Agreement	The Company holds its 37.5% participating interests in SC-80 and SC-81 as part of a joint venture with Sunda Energy Plc, PXP Energy Corporation and Philodrill Corporation, to be governed by Joint Operating	Section 7.2

Item	Summary	Further information
	Agreements (**JOAs**). As a consequence of this joint venture structure, the Company's ability to advance exploration on SC-80 and SC-81 is dependent on the agreement and co-operation of its joint venture partners, and the Company may have limited ability to unilaterally determine the timing, scope or funding of operations on those permits. The Company will be the initial operator under the JOAs, however, under the proposed terms of the JOAs, there are provisions that could materially affect the Company's interests, including onerous default mechanisms under which a failure to meet cash call or payment obligations may result in the Company losing its entitlement to production, being excluded from decision-making, and ultimately having its participating interest transferred to the other joint venture parties at a price that may be materially below fair market value. The Company's operatorship of SC-80 and SC-81 may also be terminated by the other joint venture parties in certain circumstances, including material breach, insolvency or a change in control of the Company. Any deterioration in relations with joint venture partners, failure to agree on work programmes or budgets, or exercise of remedies by other parties under the JOAs could materially affect the Company's ability to progress, and ultimately retain its interests in, SC-80 and SC-81.	
Foreign Jurisdiction Risk – Philippines	The Company's operating activities will be subject to laws and regulations governing exploration of property, health and worker safety, employment standards, waste disposal, protection of the environment, land and water use, prospecting, taxes, labour standards, occupational health standards, toxic wastes, the protection of endangered and protected species and other matters. While the Company understands that it is in substantial compliance with all material current laws and regulations affecting its activities, future changes in applicable laws, regulations, agreements or changes in their enforcement or regulatory interpretation could result in changes in legal requirements or in the terms of existing permits and agreements applicable to the Company, its subsidiary or its properties, which could have a material adverse impact on the Company's current operations or planned development projects. Where required, obtaining necessary permits and licences can be a complex, time consuming process and the Company cannot be sure whether any necessary permits will be obtainable on acceptable terms, in a timely manner or at all. The costs and delays associated with obtaining necessary permits and complying with these permits and applicable laws and regulations could stop or materially delay or restrict the Company from proceeding with any future exploration or development of its properties. Any failure to comply with applicable laws and regulations or permits, even if inadvertent, could result in interruption or closure of exploration, development or other activities and could result in material fines, penalties or other liabilities. Adverse changes in Filipino government policies or legislation may affect ownership of oil and gas interests,	Section 7.2

Item	Summary	Further information
	taxation, royalties, land access, labour relations, and production and exploration activities of the Company. It is possible that the current system of exploration and mine permitting in the Philippines may change, resulting in impairment of rights and possibly expropriation of the Company's properties without adequate compensation. Under Philippine law, all petroleum resources are owned by the State and cannot be alienated. The service contracts held by the Company confer operational rights only, subject to full control and supervision by the State. In addition, local government units in whose jurisdictions the contract areas fall are entitled under Philippine law to a share of revenues from the utilisation of natural resources. The extent and quantum of these local government revenue-sharing obligations have not yet been fully quantified and may impose additional costs on the Company. Furthermore, if any part of the contract areas is found to overlap with ancestral domain lands or areas designated as protected under the National Integrated Protected Areas System, additional approvals or legislative authority may be required before exploration activities can proceed in those areas.	
Regulatory Risk	The oil and gas industry is subject to extensive regulation, covering areas such as exploration, drilling, production, environmental management, land access, health and safety, petroleum titles, pipelines, decommissioning, and rehabilitation. The Company is required to obtain, maintain, and comply with a range of approvals, licences, and permits, together with the conditions attaching to them. Such approvals may be delayed, withheld, suspended, or revoked, and conditions may be varied or tightened over time. Failure to obtain or maintain the necessary approvals or to comply with applicable laws could result in enforcement action, restrictions on activities, increased costs, or suspension or cessation of operations. Government policy settings and legislation are also subject to change, including in areas such as royalties and taxes, greenhouse gas emissions and climate policy, methane management, domestic gas reservation, native title and heritage, and financial assurance for decommissioning. Any such changes could increase compliance costs, impose new operational constraints, reduce Projects returns, or adversely affect access to financing and insurance. There can be no assurance that the regulatory environment will not change in a way that materially and adversely impacts the Company's projects, financial position, prospects, or the value of its Shares. The Company's service contract areas may also be subject to overlapping third-party development rights, including solar energy development areas, which are permitted under Philippine energy law. While such overlaps are not currently expected to restrict the Company's petroleum exploration activities, there can be no assurance that third-party activities in or adjacent to the contract areas will not cause operational	Section 7.2

Item	Summary	Further information
	interference, access difficulties or regulatory complications that delay or increase the cost of the Company's exploration programmes.	
Entry into joint venture or operator arrangements over the Projects	The Company will seek to progress the development and commercialisation of its Projects through joint venture arrangements or by entering into agreements with third-party operators. There is a risk that the Company may not be able to negotiate such arrangements on favourable terms, or at all. Even where agreements are entered into, the Company may have limited influence over the management and operation of the Projects, particularly where another party is then appointed as operator. Joint venture or operating counterparties may have commercial or strategic interests that differ from those of the Company. Disputes may arise in relation to budgets, work programs, development decisions, funding obligations or the allocation of costs and revenues. These disputes may result in delays, increased costs, or reduced Projects returns. There is also a risk that joint venture partners or operators may default on their obligations, experience financial distress, or withdraw from the Projects. Any of these outcomes could adversely affect the timing, cost, and ultimate viability of the Projects, which in turn may have a material negative impact on the Company's financial position and prospects.	Section 7.2
Additional requirements for capital	The funds to be raised under the Public Offer (together with the existing cash reserves of the Company) are considered sufficient to meet the immediate objectives of the Company. The Company will require significant additional funding if it transitions to the development phase of its Projects and into production. In particular, the capital expenditure required to construct, commission, and operate production facilities, as well as associated infrastructure (other than existing infrastructure), is expected to exceed the funds available to the Company following completion of the Public Offer. Additional funding will also be required to support the Company's ongoing working capital requirements, to meet any cost overruns, and to pursue potential acquisitions or other business opportunities. There can be no assurance that such funding will be available when required, or on terms acceptable to the Company. Funding may be sought through equity or debt financing, joint venture, Projects operator or farm-in arrangements, or other forms of capital raising. Any equity financing may be dilutive to existing Shareholders, and debt financing (if available) may involve restrictive covenants or repayment obligations that could limit the Company's operational and financial flexibility. If the Company is unable to secure adequate funding, it may be required to delay, scale back, or suspend its development and production plans, which would materially impact its business, prospects, and financial position.	Section 7.2

<table>
<tr><th>Item</th><th>Summary</th><th>Further information</th></tr>
<tr><td>Other risks</td><td>For additional specific risks please refer to Section 7.2. For other risks with respect to the industry in which the Company operates and general investment risks, many of which are largely beyond the control of the Company and its Directors, please refer to Sections 7.3 and 7.4.</td><td>Sections 7.2, 7.3 and 7.4</td></tr>
<tr><td colspan="3">E. Board and Key Management</td></tr>
<tr><td>Who are the Directors and key management personnel?</td><td>The Board consists of:
(a) Greg Hancock – Non-Executive Chairman;
(b) Conrad Todd – Managing Director; and
(c) Mike Collins – Non-Executive Director.
Information about the experience, background and independence of each Director is set out in Section 8.1.</td><td>Section 8.1</td></tr>
<tr><td colspan="3">F. Significant interests of key people and related party transactions</td></tr>
<tr><td>What interests do the Directors have in the securities of the Company?</td><td>The table below sets out the direct and indirect interests of the Directors in the Securities of the Company both as at the date of this Prospectus and following completion of the Public Offer.
Date of Prospectus
<table>
<tr><th>Director</th><th>Shares</th><th>Options / Performance Rights</th><th>% of shares (undiluted)</th></tr>
<tr><td>Greg Hancock</td><td>32,409</td><td>Nil</td><td>0.16%</td></tr>
<tr><td>Conrad Todd</td><td>326,930</td><td>Nil</td><td>1.66%</td></tr>
<tr><td>Mike Collins</td><td>126,550</td><td>Nil</td><td>0.64%</td></tr>
</table>
Completion of Offer
<table>
<tr><th>Director</th><th>Shares</th><th>Options / Performance Rights</th><th>% of shares (undiluted)</th></tr>
<tr><td>Greg Hancock</td><td>82,409</td><td>900,000</td><td>0.33%</td></tr>
<tr><td>Conrad Todd</td><td>526,930</td><td>1,200,000</td><td>1.33%</td></tr>
<tr><td>Mike Collins</td><td>276,550</td><td>700,000</td><td>0.70%</td></tr>
</table>
Please refer to Section 8.4 for notes relating to the above table.
In addition, the Directors (and their spouses and associates) may apply for Shares under the Public Offer. If one or more of the Directors (or their associates) do apply for, and are allocated, Shares under the Public Offer, their relevant interest in the Company (as illustrated in the above table) will increase.</td><td>Section 8.4</td></tr>
<tr><td>What significant benefits are payable to the Directors in connection with the Company or the Public Offer?</td><td>The Directors are entitled to the remuneration as disclosed in Section 8.4.</td><td>Section 8.4.</td></tr>
</table>

Item	Summary	Further information
Who are the Company's substantial Shareholders, what interest will they have after completion of the Public Offer and who will the Company's substantial shareholders be on completion of the Public Offer?	The Company's existing Shareholders are all shareholders of Triangle that received their Shares in an in specie distribution. No shareholder has a relevant interest in 5% or more of the Shares on issue as at the date of this Prospectus. Based on information known to the Company as at the date of this Prospectus, no shareholder will have a relevant interest in 5% or more of the Shares on issue on completion of the Public Offer. The Company will announce to the ASX details of its top 20 Shareholders following completion of the Public Offer prior to the Shares commencing trading on ASX.	Section 5.12
Who is the lead manager to the Public Offer?	The Company has appointed Powerhouse Advisory Australia Pty Ltd (ARN 1311 365) (**Powerhouse** or the **Lead Manager**) as lead manager to the Public Offer. The Lead Manager will receive the following fees: (d) a capital raising and management fee of 6% of the gross proceeds raised under the Public Offer; and (e) 2,000,000 Options on the terms and conditions set out in Section 10.3. The Lead Manager may pass on some or all of the fees payable under the Lead Manager Mandate to other brokers or advisers who assist with the Public Offer.	Section 4.6
What are the significant interests of advisers to the Company?	Salient Corporate Pty Ltd (AFSL 499 098) (**Salient Corporate**) has acted as corporate advisors to the Company in respect of the Public Offer and will receive 1,250,000 Options on the terms and conditions set out in Section 10.3 as consideration for advisory services provided to the Company.	Section 9.2
Does the Company have an employee incentive plan?	Refer to Section 10.5 for a summary of the Company's employee incentive plan.	Section 10.5
Are there any related party transactions?	The Company has entered into an agreement with Triangle with respect to an Indonesian Joint Study, as further detailed in Section 5.7. This agreement was entered into while the Company was a wholly owned subsidiary of Triangle. In addition, the Company has entered into an executive services agreement with Conrad Todd (Managing Director), further details of which are set out in Section 9.4.1.	Sections 5.7, and 9.4.1
G. Financial information and Dividend Policy		
How has the Company been performing?	As the Company was incorporated on 6 February 2025, it has limited financial performance and no operating history. As an oil and gas exploration company (including petroleum exploration), the Company is not in a position to disclose any key financial ratios other than its statement of profit and loss, statement of cash flows and	Section 6 and Annexure C

Item	Summary	Further information
	pro-forma statement of financial position which is included in Section 6.	
What is the financial outlook for the Company?	Given the current status of the Projects and the speculative nature of its business, the Directors do not consider it appropriate to forecast future earnings. Any forecast or projection information would contain such a broad range of potential outcomes and possibilities that it is not possible to prepare a reliable best estimate forecast or projection on a reasonable basis.	Section 6 and Annexure C
What is the Company's dividend policy?	Payment of dividends by the Company is at the discretion of the Board. Given the stage of development of the Company, the Board anticipates that significant expenditure will be incurred in the evaluation and development of the Company's Projects. These activities, together with the possible acquisition of interests in other projects, are expected to dominate at least the first two-year period following the Company's Admission. Accordingly, the Directors have no current intention to declare and pay a dividend and no dividends are expected to be paid during the foreseeable future following the Company's Admission. In determining whether to declare future dividends, the Directors will consider the level of earnings of the Company, the operating results and overall financial condition of the Company, future capital requirements, capital management initiatives, general business outlook and other factors the Directors may consider relevant at the time of their decision. The Directors cannot and do not provide any assurances in relation to the future payment of dividends or the level of franking credits attaching to dividends.	Section 5.14
H. Capital Structure		
Who are the existing Shareholders of the Company?	The existing Shareholders of the Company are the shareholders of Triangle Energy (Global) Limited (ASX: TEG) who received Shares pursuant to the in-specie distribution completed as part of the Spin-out. The current capital structure of the Company is detailed in Section 5.10.	Sections 5.1 and 5.10
What will the Company's capital structure be on completion of the Public Offer and listing on ASX?	On completion of the Public Offer and the Company's listing on ASX, the Company will have 39,700,408 Shares, 3,250,000 Options and 3,900,000 Performance Rights on issue.	Section 5.10
J. Overview of the Public Offer		
What is the Public Offer?	The Public Offer is an offer of 20,000,000 Shares at an issue price of $0.20 per Share to raise $4,000,000.	Section 4.1
Is there a minimum subscription	The minimum subscription to the Public Offer is $4,000,000 (being 20,000,000 Shares at $0.20 per Share).	Section 4.3

Item	Summary	Further information
under the Public Offer?		
Why is the Public Offer being conducted?	The Public Offer is being conducted primarily to: (a) assist the Company to meet the admission requirements of ASX under Chapters 1 and 2 of the ASX Listing Rules to facilitate the Company's application for Admission; (b) provide the Company with funding for: (i) the proposed exploration programs at the Projects (as further detailed in Section 5; (ii) evaluating acquisition opportunities that may be presented to the Board from time to time; and (iii) the Company's working capital requirements while it is implementing its business strategies; (iv) provide the Company with access to capital markets to improve capital management flexibility; (v) provide the Company with the benefits of an increased profile that arises from being a listed entity; (vi) broaden the Company's shareholder base and provide a liquid market for the Shares; and (vii) pay transaction costs associated with the Public Offer.	Section 4.2
What are the Secondary Offers?	The Prospectus also contains the following secondary offers: (a) the offer of 2,000,000 Options to the Lead Manager (or its nominees); (b) the offer of 1,250,000 Options to Salient Corporate (or its nominees); and (c) the offer of an aggregate of 3,900,000 Performance Rights to Directors and management of the Company (or their nominees), (together, the **Secondary Offers**). Only specified persons will be entitled to participate in the Secondary Offers, all of whom will be approached directly by the Company.	Section 4.7
What are the purposes of the Secondary Offers	The Secondary Offers are being undertaken for the purposes of removing any trading restrictions attaching to Shares on exercise of the Options or Performance Rights to be issued under the relevant Secondary Offer, given that the Securities offered under those Offers are being issued with disclosure under this Prospectus.	Section 4.7
What is the proposed use of funds raised under the Public Offer?	The Company intends to apply funds raised under the Public Offer, together with existing cash reserves post-Admission, as set out in Section 5.8 to advance the Company's main objectives upon Admission. The Board is satisfied that following completion of the Public Offer, the Company will have sufficient working	Section 5.8

Item	Summary	Further information
	capital to carry out its stated objectives as detailed in this Prospectus.	
What is the Public Offer Price?	The price payable under the Public Offer is $0.20 per Share.	Section 4.1
What rights and liabilities attach to the Securities being offered?	A summary of the material rights and liabilities attaching to: (a) the Shares offered under the Public Offer are set out in Section 10.2; (b) the Options offered under the Lead Manager Offer and Advisor Offer are set out in Section 10.3; (c) the Performance Rights offered under the Management Offer are set out in Section 10.4.	Sections 10.2, 10.3 and 10.4
Is the Public Offer underwritten?	The Public Offer is not underwritten.	Sections 4.5
Are there any conditions to the Public Offer?	No, other than raising the Minimum Subscription and ASX approval for quotation of the Shares, the Public Offer is unconditional.	Section 4.8
Who is eligible to participate in the Public Offer?	This Prospectus does not, and is not intended to, constitute an offer or invitation in any place or jurisdiction, or to any person to whom, it would not be lawful to make such an offer or invitation or to issue this Prospectus. The distribution of this Prospectus in jurisdictions outside Australia may be restricted by law and persons who come into possession of this Prospectus should observe any of these restrictions. Any failure to comply with such restrictions may constitute a violation of applicable securities laws.	Section 4.13
How can I apply for Shares?	The process for applying for Shares in the Company is set out in Section 4.9. Applications for Shares under the Public Offer must be made by completing the Application Form attached to, or accompanying, this Prospectus in accordance with the instructions set out in Section 4.9 and the Application Form.	Section 4.9
What is the allocation policy?	The allocation of Shares under the Public Offer will be determined by the Company in consultation with the Lead Manager, having regard to the allocation policy set out in Section 4.10. No assurance can be given that any applicant will be allocated all or any Shares applied for.	Section 4.10
Will any Shares be subject to escrow?	None of the Shares issued under the Public Offer will be subject to escrow. However, subject to the Company complying with Chapters 1 and 2 of the ASX Listing Rules and completing the Offers, it is anticipated that certain Securities on issue will be classified by ASX as restricted securities and will be required to be held in escrow for up to 24 months from the date of Official Quotation. The Company anticipates that the Securities issued under the Secondary Offers will be subject to escrow for	Section 5.13

Item	Summary	Further information
	a period of 24 months from the date of Official Quotation of the Company's Shares. During the period in which restricted Shares are prohibited from being transferred, trading in Shares may be less liquid which may impact on the ability of a Shareholder to dispose of his or her Shares in a timely manner. The Company will announce to ASX full details (quantity and duration) of the Securities required to be held in escrow prior to the Shares commencing trading on ASX (which admission is subject to ASX's discretion and approval). The Company confirms its 'free float' (the percentage of the Shares that are not restricted and are held by shareholders who are not related parties (or their associates) of the Company at the time of Admission) will be not less than 20% in compliance with ASX Listing Rule 1.1 Condition 7.	
Will the Shares be quoted on ASX?	Application for quotation of all Shares to be issued under the Public Offer will be made to ASX no later than 7 days after the date of this Prospectus.	Section 4.11
What are the key dates of the Public Offer?	The key dates of the Public Offer are set out in the indicative timetable in Section 2.	Section 2
What is the minimum application size under the Public Offer?	Applications for Shares under the Public Offer must be for a minimum of $2,000 worth of Shares (10,000 Shares) and thereafter, in multiples of 2,500 Shares and payment for the Shares must be made in full at the Public Offer Price of $0.20 per Share.	Section 4.9
K. Additional information		
What are the material contracts considered by Directors to be relevant to potential investors?	The Directors consider that the material contracts which an investor would reasonably regard as material and which investors and their professional advisers would reasonably expect to find described in this Prospectus for the purpose of making an informed assessment of an investment in the Company under the Public Offer are as follows: (a) the Lead Manager Mandate with the Lead Manager; (b) the Corporate Advisory Mandate with Salient Corporate; (c) the JOAs; (d) the ESA with Conrad Todd; (e) the appointment letters between Greg Hancock, Mike Collins and the Company to act in the capacity of Non-Executive Chairman and Non-Executive Director, respectively.	Section 9
Is there any brokerage, commission or duty payable by applicants?	No brokerage, commission or duty is payable by applicants on the acquisition of Shares under the Public Offer. However, the Company will pay to the Lead Manager 6% (ex GST) of the total amount raised under the Prospectus.	Section 4.14

Item	Summary	Further information
Can the Public Offer be withdrawn?	Yes. The Company reserves the right not to proceed with the Public Offer at any time before the issue of Shares to successful applicants. If the Public Offer does not proceed, application monies will be refunded (without interest).	Section 4.16
What are the tax implications of investing in Shares?	The acquisition and disposal of Shares will have consequences, which will differ depending on the individual financial affairs of each investor. Holders of Shares may be subject to Australian tax on dividends and possibly capital gains tax on a future disposal of Shares subscribed for under this Prospectus. It is not possible to provide a comprehensive summary of the possible taxation positions of all potential applicants. As such, all potential investors in the Company are urged to obtain independent financial advice about the consequences of acquiring Shares from a taxation viewpoint and generally.	Section 4.15
What are the corporate governance principles and policies of the Company?	To the extent applicable, in light of the Company's size and nature, the Company has adopted *The Corporate Governance Principles and Recommendations (4th Edition)* as published by ASX Corporate Governance Council (**Recommendations**). The Company's main corporate governance policies and practices and the Company's compliance are outlined in Section 8.6. Prior to listing on the ASX, the Company will announce its compliance and departures from the Recommendations.	Section 8.6
Where can I find more information about this Prospectus or the Public Offer?	By speaking to your accountant, financial adviser, stockbroker, lawyer or other professional adviser; By contacting the Company Secretary, on +61 (8) 9219 7111; or By contacting the Share Registry on 61 (8) 9698 5414.	-
Can general meetings of shareholders be held using technology?	The Company's constitution permits the use of technology at general meetings of shareholders (including wholly virtual meetings) to the extent permitted under the Corporations Act, Listing Rules and applicable law.	Section 10.2

This Section is a summary only and is not intended to provide full information for investors intending to apply for Shares offered pursuant to this Prospectus. This Prospectus should be read and considered in its entirety.

4. DETAILS OF THE OFFERS

4.1 The Public Offer

The Public Offer is an initial public offering of 20,000,000 Shares at an issue price of $0.20 per Share to raise up to $4,000,000.

All Shares offered under this Prospectus will be fully paid and will rank equally with the existing Shares currently on issue. Please refer to Section 10.2 for a summary of the material rights and liabilities attaching to the Shares.

The Public Offer is made on the terms and is subject to the conditions set out in this Prospectus.

4.2 Purpose of the Public Offer

The primary purposes of the Public Offer are to:

(a) assist the Company to meet the admission requirements of ASX under Chapters 1 and 2 of the ASX Listing Rules to facilitate the Company's application for Admission;

(b) provide the Company with funding for:

  (i) the proposed activities to advance the Projects (as further detailed in Section 5); and

  (ii) the Company's working capital requirements while it is implementing its business strategies;

(c) provide the Company with access to capital markets to improve capital management flexibility;

(d) provide the Company with the benefits of an increased profile that arises from being a listed entity;

(e) broaden the Company's shareholder base and provide a liquid market for the Shares; and

(f) pay transaction costs associated with the Public Offer.

The Company intends to apply the funds raised under the Public Offer together with its existing cash reserves in the manner detailed in Section 5.8.

4.3 Minimum subscription

The minimum subscription to the Public Offer is the Minimum Subscription of 20,000,000 Shares to raise $4,000,000 (before associated costs) (**Minimum Subscription**).

If the Minimum Subscription has not been raised within four months after the date of this Prospectus or such period as varied by the ASIC, no Securities will be issued under the Offers and the Company will repay all application monies for the Shares under the Public Offer within the time prescribed under the Corporations Act, without interest.

4.4 Oversubscriptions

No oversubscriptions will be accepted in respect of the Public Offer.

4.5 No underwriting

The Public Offer is not underwritten.

4.6 Lead Manager

The Company has appointed Powerhouse Advisory Australia Pty Ltd (ARN 1311 365) (**Powerhouse** and the **Lead Manager**) as the Lead Manager to the Public Offer.

In consideration for services provided, the Lead Manager will receive:

(a) a capital raising and management fee of 6% of the gross proceeds raised under the Public Offer; and

(b) 2,000,000 Options on the terms and conditions set out in Section 10.3.

The Lead Manager may pass on some or all of the fees payable under the Lead Manager Mandate to other brokers or advisers who assist with the Public Offer.

For further information in relation to the appointment of the Lead Manager, please refer to Section 9.1.

4.7 Secondary Offers

This Prospectus also contains the following secondary offers:

(a) the offer of 2,000,000 Options to the Lead Manager (or its nominees) (**Lead Manager Offer**);

(b) the offer of 1,250,000 Options to Salient Corporate Pty Ltd (AFSL 499 098) (**Salient Corporate**) (or its nominees) (**Advisor Offer**); and

(c) the offer of an aggregate of 3,900,000 Performance Rights to Directors and management of the Company (or their nominees) (**Management Offer**),

(together, the **Secondary Offers**).

The purpose of the Secondary Offers is to remove any trading restrictions attaching to Shares on exercise or conversion of the Options or Performance Rights to be issued under the relevant Secondary Offer, given that the Securities offered under the Secondary Offers are being issued with disclosure under this Prospectus. The Secondary Offers will open on the opening date of the Public Offer and remain open until the Company's admission to the Official List, unless closed earlier by the Company, in its sole discretion.

Each of the Secondary Offers is only available for application by those persons invited to participate in the relevant Offer, being:

(a) in the case of the Lead Manager Offer, the Lead Manager (or its nominees);

(b) in the case of the Advisor Offer, Salient Corporate (or its nominees); and

(c) in the case of the Management Offer, certain Directors and management of the Company, including Greg Hancock, Conrad Todd, Mike Collins and Marvin Chan and Rory McGoldrick (or their respective nominees).

An Application Form and instructions on how to apply in relation to the Secondary Offers will only be provided to the relevant parties by the Company. Applications for Securities under the Secondary Offers must only be made using the Application Form to be provided by the Company and attached to, or accompanying this, Prospectus. The Company reserves all discretions in relation to applications under the Secondary Offers.

The Shares issued upon the future exercise of Options or conversion of Performance Rights issued under the Secondary Offers will rank equally with the Shares on issue at the date of this Prospectus. A summary of the material rights and liabilities attaching to the Shares is set out in Section 10.2. The Options under the Lead Manager Offer and Advisor Offer will be issued on the terms and conditions set out in Section 10.3 and the Performance Rights under the Management Offer will be issued on the terms and conditions set out in Section 10.4.

No payment is required to subscribe for Securities under the Secondary Offers. Accordingly, no funds will be raised pursuant to the Secondary Offers. The Company will not apply for quotation of the Securities to be issued under the Secondary Offers.

4.8 Conditions of the Offers

The Offers are conditional upon the following conditions being satisfied:

(a) the Company receiving sufficient applications to meet the Minimum Subscription under the Public Offer (see Section 4.3 for further information); and

(b) ASX granting conditional approval for the Company to be admitted to the Official List of the ASX on conditions reasonably acceptable to the Company,

(together the **Conditions**).

If the Conditions are not satisfied then the Offers will not proceed and the Company will repay all application monies received under the Public Offer within the time prescribed under the Corporations Act, without interest.

4.9 Applications

Applications for Shares under the Public Offer must be made by using the relevant Application Form available online at **https://apply.automic.com.au/TetragonEnergy** and paying the application monies electronically via BPAY® or EFT (Electronic Funds Transfer).

Should you be unable to access the online Application Form, please contact the Company on + 61 (8) 9698 5414 to arrange access to a paper-based application form.

By completing an Application Form, each applicant under the Public Offer will be taken to have declared that all details and statements made by them are complete and accurate and that they have personally received the Application Form together with a complete and unaltered copy of the Prospectus.

Applications for Shares under the Public Offer must be for a minimum of $2,000 worth of Shares (10,000 Shares) and thereafter in multiples of 2,500 Shares and payment for the Shares must be made in full at the Public Offer Price of $0.20 per Share.

Completed Application Forms must be received by no later than 5:00pm (WST) on the Closing Date, which is scheduled to occur on Friday, 12 June 2026.

A reference number will be quoted upon completion of the online application. Your BPAY or EFT reference number will process your payment to your application electronically and you will be deemed to have applied for such Shares for which you have paid. Applicants using BPAY or EFT should be aware of their financial institution's cut-off time (the time payment must be made to be processed overnight) and ensure payment is processed by their financial institution on or before the day prior to the Closing Date. You do not need to return any documents if you have made payment by BPAY or EFT.

If an Application Form is not completed correctly or if the accompanying payment is the wrong amount, the Company may, in its discretion, still treat the Application Form to be valid. The Company's decision to treat an application as valid, or how to construe, amend or complete it, will be final.

The Company reserves the right to close the Public Offer early.

4.10 Allocation policy under the Public Offer

The allocation of Shares under the Public Offer will be determined by the Company in consultation with the Lead Manager.

The Company, in consultation with the Lead Manager, retains an absolute discretion regarding the basis of allocation of Shares under the Public Offer and reserves the right, in its absolute discretion, to allot to any applicant a lesser number of Shares than the number for which the applicant applies for or to reject any application. If the number of Shares allotted is fewer than the number applied for, surplus application money will be refunded without interest as soon as practicable.

No applicant under the Public Offer has any assurance of being allocated all or any Shares applied for. The allocation of Shares by Directors (in consultation with the Lead Manager) will be influenced by the following factors:

(a) the number of Shares applied for by particular applicants;

(b) the overall level of demand under the Public Offer;

(c) the Company's desire for an informed and active trading market following its listing on ASX;

(d) the Company's desire to establish a wide spread of investors, including institutional investors;

(e) recognising the ongoing support of existing Shareholders;

(f) the likelihood that particular applicants will be long-term Shareholders;

(g) the desire for an informed and active market for trading Shares following completion of the Public Offer;

(h) ensuring an appropriate Shareholder base for the Company going forward; and

(i) any other factors that the Company and the Lead Manager consider appropriate.

The Company will not be liable to any person not allocated Shares or not allocated the full amount applied for.

4.11 ASX listing

Application for Official Quotation by ASX of the Shares offered pursuant to this Prospectus will be made within 7 days after the date of this Prospectus. However, applicants should be aware that ASX will not grant Official Quotation of any Shares until the Company has complied with Chapters 1 and 2 of the ASX Listing Rules and has received the approval of ASX to be admitted to the Official List. Accordingly, the Shares may not be able to be traded for some time after the close of the Public Offer.

If the Shares are not admitted to Official Quotation by ASX before the expiration of three (3) months after the date of this Prospectus, or such period as varied by the ASIC, the Company will not issue any Shares under the Public Offer and will repay all application monies for the Shares within the time prescribed under the Corporations Act, without interest.

The Company will not apply for Official Quotation of the Options or Performance Rights issued under the Secondary Offers to this Prospectus.

The fact that ASX may grant Official Quotation to the Shares is not to be taken in any way as an indication of the merits of the Company or the Securities offered for subscription under this Prospectus.

4.12 Issue

Subject to the Conditions set out in Section 4.8 being satisfied, issue of Shares offered by this Prospectus will take place as soon as practicable after the Closing Date.

Pending the issue of the Shares or payment of refunds pursuant to this Prospectus, all application monies will be held by the Company in trust for the applicants in a separate bank account as required by the Corporations Act. However, the Company will be entitled to retain all interest that accrues on the bank account, and each applicant waives the right to claim interest.

The Directors (in consultation with the Lead Manager) will determine the recipients of the Shares in their sole discretion in accordance with the allocation policy detailed in Section 4.10). The Directors reserve the right to reject any application or to allocate any applicant fewer Shares than the number applied for. Where the number of Shares issued is less than the number applied for, or where no issue is made, surplus application monies will be refunded without any interest to the applicant as soon as practicable after the Closing Date.

Holding statements for Shares allocated to the Company's sponsored subregister and confirmation of allocation for Clearing House Electronic Subregister System (CHESS) holders will be mailed to applicants being allocated Shares under the Public Offer as soon as practicable after their issue.

4.13 Applicants outside Australia

This Prospectus does not, and is not intended to, constitute an offer in any place or jurisdiction, or to any person to whom, it would not be lawful to make such an offer or to issue this Prospectus.

The distribution of this Prospectus in jurisdictions outside Australia is restricted by law and persons who come into possession of this Prospectus should observe such restrictions, including those outlined below. In particular, this Prospectus may not be distributed outside Australia, except to Institutional Investors in Hong Kong, Singapore and the Philippines, in transactions exempt from local prospectus or registration requirements. Any failure to comply with such restrictions may constitute a violation of applicable securities laws. The return of a completed Application Form will be taken by the Company to constitute a representation and warranty by you that you have complied with these restrictions.

Further details in respect of participation by Institutional Investors in Hong Kong, Singapore and the Philippines in are set out in the Important Notices Section.

4.14 Commissions payable

The Company reserves the right to pay commissions of up to 6% (exclusive of goods and services tax) of amounts subscribed through any licensed securities dealers or Australian financial services licensees in respect of any valid applications lodged and accepted by the Company and bearing the stamp of the licensed securities dealer or Australian financial services licensee. Payments will be subject to the receipt of a proper tax invoice from the licensed securities dealer or Australian financial services licensee.

The Lead Manager will be responsible for paying all commission that they and the Company agree with any other licensed securities dealers or Australian financial services licensees out of the fees paid by the Company to the Lead Manager.

4.15 Taxation

The acquisition and disposal of Shares will have tax consequences, which will differ depending on the individual financial affairs of each investor. Holders of Shares may be subject to Australian tax on dividends and possibly capital gains tax on a future disposal of Shares subscribed for under this Prospectus.

It is not possible to provide a comprehensive summary of the possible taxation positions of all prospective applicants. As such, all prospective investors in the Company are urged to obtain independent taxation and financial advice about the consequences of acquiring Shares from a taxation viewpoint and generally.

To the maximum extent permitted by law, the Company, its officers and each of their respective advisers accept no liability and responsibility with respect to the taxation consequences of subscribing for Shares under this Prospectus or the reliance of any applicant on any part of the summary contained in this Section.

No brokerage, commission or duty is payable by applicants on the acquisition of Shares under the Public Offer.

4.16 Discretion regarding the Offers

The Offers may be withdrawn at any time. If the Offers do not proceed, all relevant application monies will be refunded (without interest) in accordance with applicable laws.

The Company also reserves the right to close the Offers (or any part of them) early, extend the Offers (or any part of them), accept late applications either generally or in particular cases, reject any application or bid, or allocate to any applicant fewer Shares than applied for.

5. COMPANY AND PROJECTS OVERVIEW

5.1 Overview of the Company

Tetragon is an Australian energy company primarily focused on developing oil and gas assets in South-east Asia. The Company was incorporated on 6 February 2025 as a wholly owned subsidiary of Triangle Energy (Global) Limited (ACN 110 411 428) (ASX: TEG) (**Triangle**) for the purpose of exploration and development of oil and gas projects held by Triangle, specifically in South-East Asia.

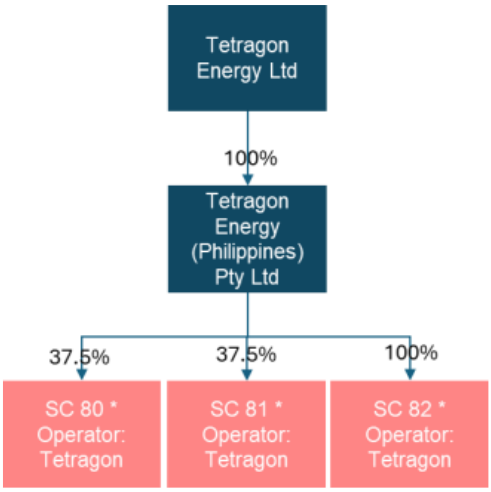
The Company holds three recently awarded petroleum exploration blocks located in the Philippines: SC-82 (onshore Luzon and 100% interest) and SC-80 and SC-81 (offshore Sulu Sea and a 37.5% interest) (the **Projects**).

In March 2026, the board of Triangle resolved to pursue a spin-out of the Company's interest in the Projects (the **Spin-out**). The Spin-out was effected by an equal reduction of Triangle's capital, satisfied by an in specie distribution of the existing Shares to eligible Triangle shareholders on a pro rata basis (In-specie Distribution). Approval to undertake the In-specie Distribution was obtained from Triangle's shareholders on 24 April 2025.

Further information with respect to the Spin-out is set out in the Triangle Notice of General Meeting dated 20 March 2026.

5.2 Corporate structure

The Company's corporate structure upon Admission will be as follows:



5.3 Overview of the Projects

The Company has an interest in three Petroleum Service Contracts (PSCs) in the Philippines. SC-82 is an onshore block on the Island of Luzon, in the Cagayan Basin, some 250km north-east of Manila city. The two other blocks, SC-80 and SC-81, are located in the south Sulu Sea near the island of Borneo.

A comprehensive summary of regional and local geology, historical exploration pertaining to the Projects and their development is contained in the Independent Technical Specialist's Report in Annexure A.

A comprehensive summary of the status of the petroleum service contracts comprising the Projects can be found in the Solicitor's Report on Title in Annexure B.

5.3.1 Tenure

The Projects tenure comprises:

PERMIT NUMBER	LOCATION	AREA	PERMIT EXPIRY	REGISTERED HOLDER
SC-80	Offshore, southern Sulu Sea	7,800 km^2	24 September 2032	Tetragon (37.5%) Sunda Energy Plc (37.5%) PXP Energy Corporation

				(12.5%) Philodrill Corporation (12.5%)
SC-81	Offshore, southern Sulu Sea	5,320 km²	24 September 2032	Tetragon (37.5%) Sunda Energy Plc (37.5%) PXP Energy Corporation (12.5%) Philodrill Corporation (12.5%)
SC-82	Onshore, Luzon, Cagayan Basin	4,800 km²	24 September 2032	Tetragon (100%)

Refer to the Solicitor's Report on Title in Annexure B for further details.

5.3.2 SC-82

Service Contract-82 is a gas exploration and appraisal/development opportunity for the Company. The block is located onshore on the island of Luzon in the Philippines, some 250km from Manila (Figure 1). It is adjacent to the San Antonio gas field and PNOC's Mangosteen discovery.

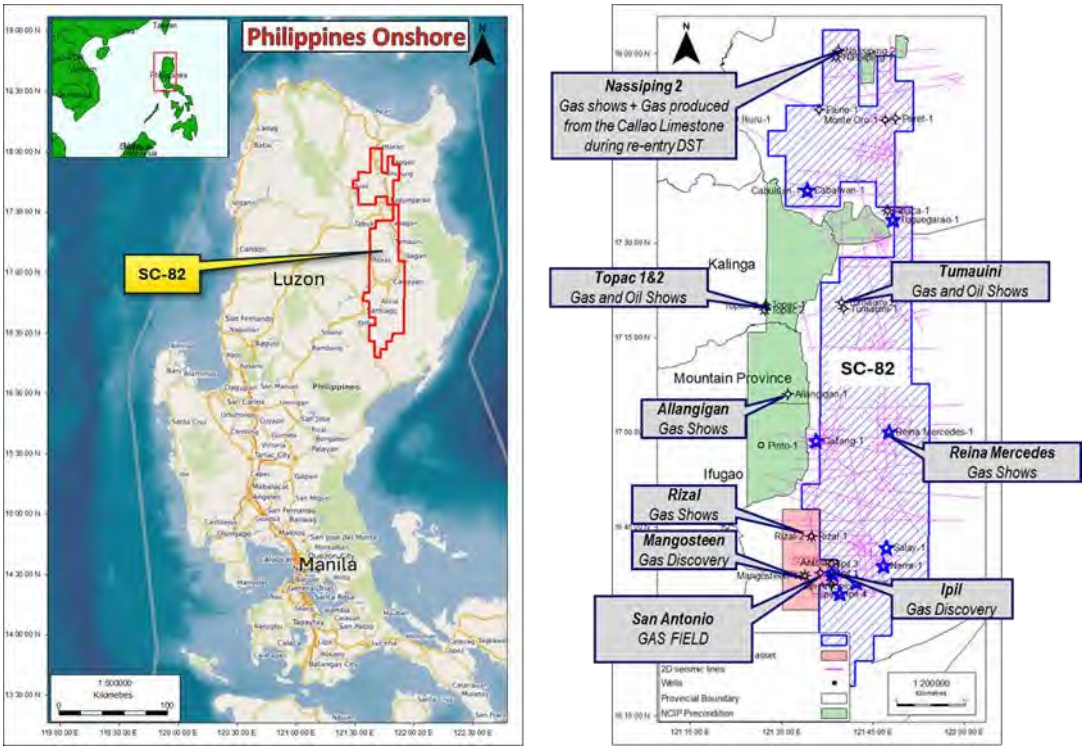


Figure 1: SC-82 permit location

In the north of SC-82, the unproduced Nassiping-2 gas discovery contains gas that could be produced to generate electricity into a nearby interconnector line (similar to the San Antonio gas field). The well was drilled in 1984 but not tested until 2012, some 28 years later, when Frontier Oil Corporation re-entered the wellbore. During the re-entry, the well produced a mixture of formation water and hydrocarbon gas from the Callao Limestone (Middle Miocene) at depths between 2,856 and 3,005mMD (Metres, Measured Depth), with flow rates averaging approximately 110 Mscf/d (Thousand Standard Cubic Feet per Day); however, no stable rate was established and the test was abandoned due to well problems. Following the Company's technical re-evaluation, there is potential to drill an appraisal well which could produce at commercial gas flow rates subject to successful appraisal. This area will be a strong focus for Tetragon who has a 100% interest in the permit and is operator. The immediate work program is to source and reprocess the seismic data over the permit.

5.3.3 SC-80 and SC-81

Service Contracts 80 and 81 are located offshore in the Sandakan Basin part of the Sulu Sea, Philippines close to the island of Borneo (Figure 2). Tetragon holds a 37.5% interest in both SC-80 and SC-81 and is the operator of both permits.

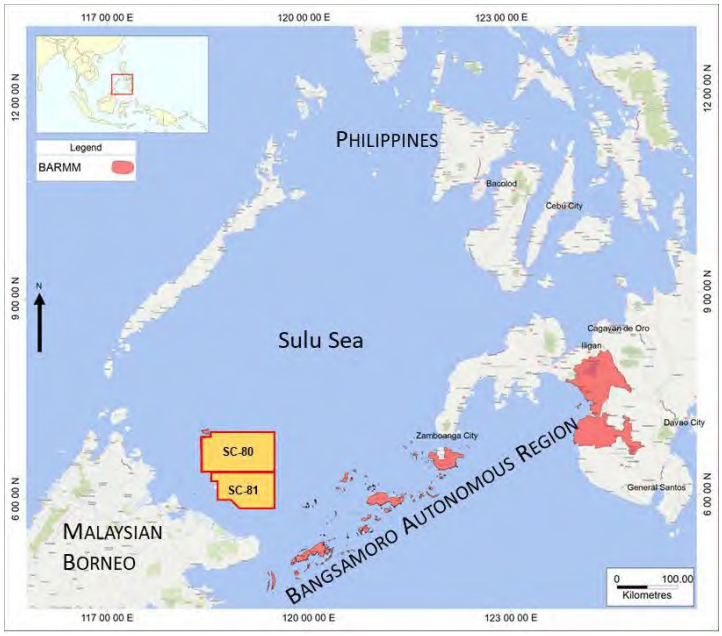


Figure 2: SC-80 & 81 location

The Permits contain two existing gas discoveries and numerous wells with hydrocarbon shows. They lie in one of the least explored areas of the prolific Circum-Borneo hydrocarbon province (Figure 3).

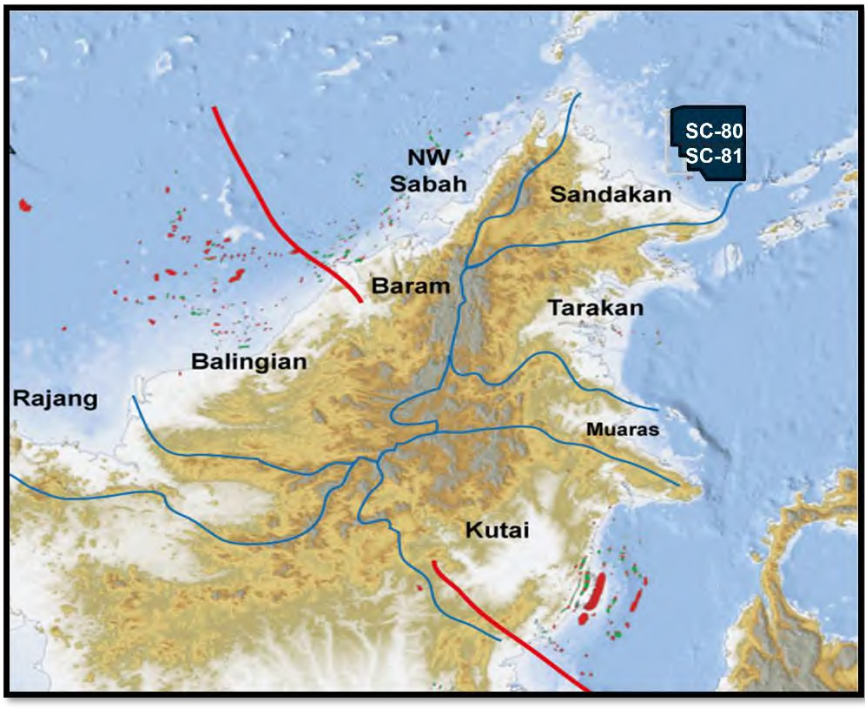


Figure 3: Location of SC-80 & 81 in the Circum-Borneo hydrocarbon province

A geoseismic cross-section (Figure 4) shows the two discoveries in SC-80, Dabakan-1 and Palendag-1, which contain gross 2C Contingent Resources of approximately 470 Bcf gas and 5 MMbbl condensate (100% basis; Tetragon's 37.5% net 2C Contingent Resources are 176 Bcf gas and 2 MMbbl condensate). Please refer to the Independent Technical Specialist's Report at Annexure A for further details including 1C and 3C estimates.

Outboard of the discoveries and to the northeast is the large Halcon prospect. There is no certainty that it will be commercially viable to produce any portion of the resources.

Dabakan-1 was drilled in 2009 by ExxonMobil (with Mitra and BHP Billiton as partners) in a water depth of 1,802m to a total depth of 4,813mTVDSS (Metres True Vertical Depth Subsea), encountering gas in multiple Miocene turbidite sandstone reservoirs between approximately 2,950mTVDSS and 4,350mTVDSS. Palendag-1A was drilled in 2010 by the same partnership in a water depth of 1,937m, encountering gas in four stacked reservoir zones between approximately 3,700mTVDSS and 4,700mTVDSS. No flow tests were attempted in either well; pressure data confirmed the presence of moveable gas with moderate to good reservoir quality (effective porosities typically 13-23%). Other wells drilled within the SC-80 and SC-81 area include Rhino-1 (2004), Zebra-1 (2004), Lumba Lumba-1 (2008), Banduria-1 (2010, dry hole) and Babendil-1 (2010, sub-commercial gas). Hydrocarbons have been confirmed in 12 of the 16 wells drilled in the SC-80 and SC-81 area. Refer to the Independent Technical Specialist's Report at Annexure A for further detail.

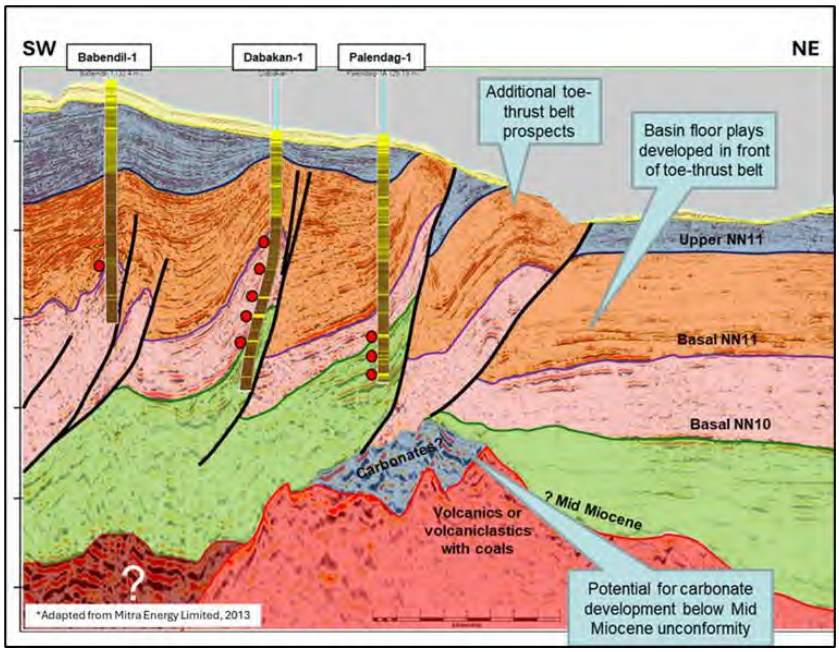


Figure 4: Geoseismic cross-section across SC-80.

The immediate work program is to reprocess the four 3D seismic surveys within the two permits.

The Halcon prospect is defined on two 3D seismic surveys and is considered to be a very large turbidite fan, shown on (Figure 5), on the seismic processed for "sweetness"[1] which indicates the presence of sandstone reservoirs.

[1] Sweetness is a composite seismic attribute used to highlight thick, clean reservoirs and may indicate hydrocarbons in certain conditions.

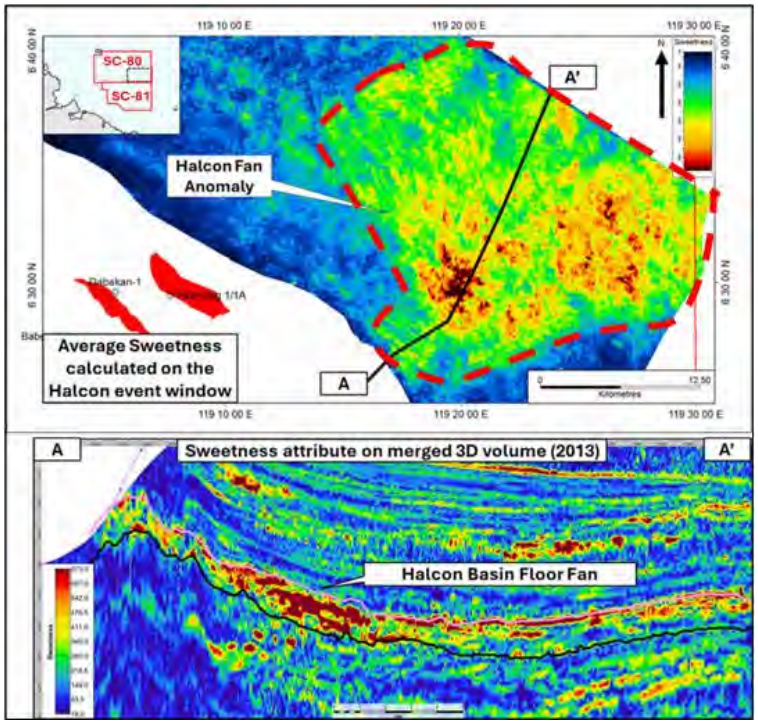


Figure 5: Halcon Prospect

Technical data and other detailed information about the Projects can be found in the Independent Technical Specialist's Report at Annexure A. Investors are urged to read that report.

5.4 Business model and strategy

On completion of the Offer the Company's primary focus will be to explore the Projects using a variety of techniques such as seismic reprocessing, interpretation of well and seismic data, seismic acquisition and interpretation and drilling to create value for Shareholders through the discovery and development of economic oil and gas resources. The Company ultimately aims to progress from exploration, subject to the results of its exploration activities, technical studies and availability of appropriate funding, into development and ultimately into an oil and gas producer. The Company aims to achieve this by:

(a) undertaking systematic exploration activities on the Projects, with the aim of discovering economic resources;

(b) undertaking economic and technical assessments of the Projects in line with industry standards (for example, the completion of a scoping study, then a preliminary feasibility study, followed by a definitive feasibility study);

(c) securing sufficient funding and/or development partners; and

(d) undertaking project development and production activities;

(e) forming strategic partnerships focused on securing upstream operating and equity partners, possessing the requisite experience, technical competence and financial capability to manage the development and eventual commercialisation of the Projects;

(f) progressing required regulatory and environmental approvals consistent with offshore petroleum and environmental regimes in Filipino waters, including connection to existing facilities offshore and State regulatory approvals for onshore facilities;

(g) further assessment of the discovered resource and exploration upside of the Projects with the intention to increase future asset value and Projects economics; and

(h) assessing growth opportunities to maximise shareholder value.

Although the Company's immediate focus will be on the Philippines Projects, as with most exploration entities, it will pursue and assess other new business opportunities in the oil and gas sector over time which complement its business and objectives. These new business opportunities may take the form of applications in bid rounds, direct project acquisitions, joint ventures, farm-ins, and/or direct equity participation. The Board will assess the suitability of investment opportunities by utilising its experience in evaluating projects. There are uncertainties in the process of identifying and acquiring new and suitable projects. The Company confirms that it is not currently considering other acquisitions and that future acquisitions will be in the energy sector.

5.5 Proposed Exploration Program and Development Plan

5.5.1 SC-82

Onshore Permit SC-82 contains old seismic data and old wells, Tetragon will gather all data possible if in electronic format and transcribe these onto modern media. These data will then be reprocessed in the case of seismic data and re-evaluated in the case of well data. As the seismic data over Permit SC-82 is sparse and not all is likely to be available for reprocessing, Tetragon plans to acquire an airborne gradiometry, gravity and magnetic survey over the whole of the permit in year 2. It is expected that the combination of the existing seismic and well data with the new airborne data will result in a better understanding of the geology and prospects distribution across the permit.

At present the highest ranked target is a reef drilled by the Nassiping-2 well in 1984, which proved gas, but did not prove a flow rate. This would have to be re-drilled and a flow rate established. Tetragon is evaluating the economics of using that gas to generate power on-site either for sale to the local grid or to nearby mine sites.

	Work programs
Onshore block, SC-82	Years 1 and 2 (committed): Reprocess a total of 3,600 line-km of 2D seismic data; source and digitize historical well data; and geological and geophysical studies, geochemical studies estimated minimum expenditure of US$425,000. Years 3 and 4 (discretionary): Seismic interpretation; stratigraphic and structural studies; prospect screening for seismic acquisition; and geological and geophysical, minimum expenditure US$450,000. Year 5 onwards (discretionary): Acquisition of 200 line-km of geophysical data, drill one exploration well and complete associated geological and geophysical studies at an estimated minimum expenditure of US$6.4 million.

5.5.2 SC-80 and SC-81

In Permits SC -80 & 81, Tetragon has retrieved the original data tapes for the four 3D surveys, we have obtained an export license and shipped them to Perth where they are being collated and copied. The Company is preparing to request bids for the reprocessing of that seismic data and hope to be in a position to award that contract in Q3 this year. The seismic reprocessing project is expected to run for about 12 months, during which time the Company will also complete new petrophysical evaluations of the wells drilled over the two permits. The new seismic and petrophysical analysis will lead to a better understanding of the prospects and resources over these permits.

	Work programs
Offshore block SC-80	Years 1 and 2 (committed): Data gathering, 3D seismic reprocessing, seismic interpretation and geological and geophysical studies at an estimated minimum expenditure of US$1 million. Years 3 and 4 (discretionary): Advanced geophysical studies, seismic interpretation, resource and risk analysis, well planning, development and economic studies at an estimated minimum expenditure of US$1 million.

	Year 5 onwards (discretionary): Drill one deep well (over 3000m sub surface) or two exploration wells and complete associated development studies at an estimated minimum expenditure of US$31 million.
Offshore block SC-81	Years 1 and 2 (committed): Data gathering, 3D seismic reprocessing, seismic interpretation and geological and geophysical studies at an estimated minimum expenditure of US$1 million. Years 3 and 4 (discretionary): Advanced geophysical studies, seismic interpretation, resource and risk analysis, well planning, development and economic studies at an estimated minimum expenditure of US$1 million. Year 5 onwards (discretionary): Drill one deep well (over 3000m sub surface) or two exploration wells and complete associated development studies at an estimated minimum expenditure of US$31 million.

5.6 About Tetragon's partners in SC-80 and SC-81

Sunda Energy plc is an independent gas-focussed company with a material undeveloped gas field and a growing business in SE Asia. The Company is quoted on the AIM market of the London stock exchange (SNDA.L). It operates a PSC in offshore Timor-Leste containing the Chuditch gas field and has minority interests in other energy assets in the UK. Sunda Energy plc has an 37.5% interest in SC-80 and SC-81.

PXP Energy Corporation, is a Philippine corporation and listed on the second board of the Philippine Stock (stock symbol: PXP). The Company is mainly involved in the exploration, development and production of Philippines and South-East Asian hydrocarbon assets. Currently, it has interests in various PSCs in the Philippines as operator and non-operator. PXP Energy Corporation has an 12.5% interest in SC-80 and SC-81.

The Philodrill Corporation was incorporated in 1969 as the Philippine Overseas Drilling and Oil Development Corporation, and was one of the pioneers in the Philippine oil exploration industry. Philodrill is now a diversified company listed on the main board of the Philippine Stock Exchange (stock symbol: OV), but continues to focus on its core business of petroleum exploration and production. Philodrill's portfolio includes exploration and production assets as operator and non-operator. The company also has investments in sectors such as mining, infrastructure, and financial services. The Philodrill Corporation has an 12.5% interest in SC-80 and SC-81.

5.7 Indonesian Joint Study

The Company has entered into a terms sheet with Triangle and Winchester Energy Limited (**Winchester**) to support a joint study over an offshore exploration area in Indonesian waters (**Joint Study**). The Company has agreed to assist Triangle to jointly fund the study and performance bond. In exchange, the Company will have an option to acquire a 24.5% interest in any petroleum licence or PSC awarded to Triangle over the study area.

Triangle commenced the Joint Study in March 2026 in conjunction with an Indonesian technical institute, under the oversight of the Directorate General of Oil and Gas and SKK Migas (**SKK Migas**). The study is expected to take 6 to 8 months at a cost of approximately US$300,000. Triangle has arranged a US$500,000 performance bond through an Australian bank in favour of SKK Migas (**Performance Bond**). The Company and Winchester have each agreed to provide A$500,000 in security funding (totalling A$1,000,000) as cash collateral for this facility, held in a controlled trust account pending release of the Performance Bond.

A Joint Study in Indonesia is a pre-licensing arrangement coordinated by SKK MIGAS, allowing companies to evaluate open acreage before it is offered under a PSC bid round. Participants access government data and undertake geological, geophysical, and economic assessments at their own cost. While the acreage is ultimately awarded through a competitive PSC process, Joint Study participants may receive preferential consideration or a right to match competing bids for a PSC.

As any future PSC application will be subject to a competitive process, the parties cannot disclose the location or technical details regarding the study area at this time. If the results of the study are compelling, Triangle intends to apply for a PSC over the study area.

The Company notes that the study itself does not grant any exploration or production rights, but culminates in a technical and commercial proposal for a PSC. There can be no certainty that a licence or PSC will be granted or that any exploration project will eventuate. The Company will keep the market informed in accordance with its continuous disclosure obligations and provide full details as the study progresses.

The key terms of the Agreement with Triangle are as follows:

(a) Triangle has arranged the Performance Bond in favour of SKK Migas and the Company and Winchester have each agreed to provide A$500,000 in security funding as cash collateral for this facility, held in a controlled trust account pending release of the Performance Bond (**Security Funding**).

(b) The Security Funding is refundable to the Company and Winchester once the Performance Bond is released.

(c) The Company will fund 24.5% of the Joint Study costs (approximately US$73,500).

(d) The Company will have an option to acquire a 24.5% interest in any petroleum licence or PSC awarded to Triangle over the study area.

(e) Parties to negotiate a formal joint operating agreement based on customary oil & gas terms.

For the avoidance of doubt, the Company's funding of Joint Study costs does not confer any interest in a PSC or petroleum licence over the study area. Any such interest is contingent on the grant of a PSC in favour of Triangle, which remains subject to regulatory approval and cannot be guaranteed.

5.8 Use of funds

The Company intends to apply funds raised from the Public Offer, together with existing cash reserves post-Admission, over the first two years following Admission as follows:

FUNDS AVAILABLE	$	%
Existing cash reserves[1]	1,500,000	27.27%
Funds raised from the Offer	4,000,000	72.73%
Total funds	**5,500,000**	**100.00%**
Allocation of funds		
Exploration on SC-822	2,310,000	42.00%
Exploration on SC-80 and 81[2]	1,380,000	25.09%
Exploration/evaluation costs at additional projects if acquired post-listing	316,000	5.75%
Working capital[3]	866,718	15.76%
Expenses of the Offer[4]	627,282	11.41%
Total funds	**5,500,000**	**100.00%**

Notes:

1. Refer to the financial information set out in Section 6 for further details. The Company intends to apply these funds towards the purposes set out in this table, including the payment of the expenses of the Public Offer of which various amounts will be payable prior to completion of the Public Offer. Since 30 June 2025, the Company has expended approximately $220,000 in preparing the Prospectus.
2. Refer to the Independent Technical Specialist's Report in Annexure A for further details with respect to the Company's proposed work programs at the Projects.
3. To the extent that the Company's work programs warrant further funding, the Company's working capital will also be utilised to fund such further activities. Any amounts not so expended will be applied toward corporate and administration costs for the period subsequent to the initial two-year period following Admission.

4. Refer to Section 10.10 for further details.

The above table is a statement of current intentions as of the date of this Prospectus. Prospective investors should note that, as with any budget, the allocation of the funds may change depending on various intervening events and new circumstances, including the outcome of exploration and development activities, regulatory developments and market and general economic conditions. Accordingly, the Board reserves the right to alter the way funds are applied on this basis.

It is anticipated that the funds raised under the Public Offer will enable two years of full operations. It should be noted that it is unlikely that the Company will be fully self-funded through its own operational cash flow at the end of this period. Accordingly, the Company may require additional capital beyond this point, which will likely involve the use of additional debt or equity funding. Future capital needs will also depend on the success or failure of the Company's Projects. The Board will consider the use of additional debt or equity funding where it is appropriate to accelerate growth, fund additional exploration and development activities on the Projects or to capitalise on acquisition or investment opportunities in the oil and gas sector.

The Directors consider that following completion of the Public Offer, the Company will have sufficient working capital to carry out its stated objectives. However, it should be noted that an investment in the Company is highly speculative, and prospective investors are encouraged to read the risk factors outlined in Section 7.

5.9 Key dependencies of the Company's business model

The key dependencies influencing the viability of the Company's business model are:

(a) maintaining title to the Projects;

(b) the Company's ability to obtain and retain all necessary approvals (including any regulatory or third-party approvals) required to undertake its proposed work programs;

(c) ability to secure Projects partners including operator, joint venture partners, offtakers and infrastructure partners to enable the development and operation of the Projects;

(d) successful completion of development studies, including seismic reprocessing on the Projects, resulting in increased confidence in the commercial viability of the Projects and progression towards drilling;

(e) retaining and recruiting key personnel skilled in the oil and gas sector;

(f) sufficient worldwide demand for LNG and local demand for gas;

(g) the market price of LNG and gas supporting the Projects commercial viability; and

(h) minimising environmental impacts and complying with environmental and health and safety requirements.

5.10 Capital structure

The capital structure of the Company as at the date of this Prospectus and following completion of the Public Offer is set out in the table below:

Shares[1]

Shares currently on issue[2]	19,700,408
Shares to be issued under the Public Offer[3]	20,000,000
Total Shares on completion of the Offers	**39,700,408**

Notes:

1. The material rights and liabilities attaching to the Shares are summarised in Section 10.2.
2. Shares distributed to Triangle shareholders pursuant to the In-specie Distribution.

3. Assuming the Minimum Subscription of $4,000,000 is achieved under the Public Offer.

Options

Options currently on issue	Nil
Options to be issued under the Lead Manager Offer[1]	2,000,000
Options to be issued under the Advisor Offer[1]	1,250,000
Total Options on completion of the Offers	**3,250,000**

Notes:

1. Refer to Sections 10.3 for the terms of the Lead Manager Offer and the Advisor Offer and the terms and conditions of the Options to be issued under the Lead Manager Offer and Advisor Offer, respectively.

Performance Rights

Performance Rights currently on issue	Nil
Performance Rights to be issued under the Management Offer[1]	3,900,000
Total Performance Rights on issue after completion of the Offers	**3,900,000**

Notes:

1. Refer to Sections 10.4 for the terms of the Management Offer and the terms and conditions of the Options to be issued under the Management Offer, respectively.

5.11 Loyalty Options

Subject to completion of the Public Offer and listing on the ASX, it is the Company's present intention that it will undertake a pro rata non-renounceable entitlement issue of Options to existing Shareholders that are registered as members of the Company on or about the date which is 3 months from the date that the Company's Shares are admitted to trading on the Official List.

These Options would be offered under a separate prospectus for nil or a nominal issue price per Option. The Company presently intends to offer one Option for every two Shares held by eligible Shareholders on the record date (other than Shares held by Shareholders with a registered address outside of Australia or New Zealand). It is expected that the Options will be exercisable at $0.40 each with an expiry date approximately two years from the date of issue of the Options. Notwithstanding the above, the Board will retain full discretion as to whether to proceed with, or to vary, the terms and timing of any such offer.

If the offer proceeds on the terms above, the Company could potentially issue 19,850,204 Options raising approximately $7.9 million if all those Options were eventually exercised over the following two years.

5.12 Substantial Shareholders

No shareholder has a relevant interest in 5% or more of the Shares on issue as at the date of this Prospectus.

Based on information known to the Company as at the date of this Prospectus, no shareholder will have a relevant interest in 5% or more of the Shares on issue on completion of the Public Offer. The Company will announce to the ASX details of its top 20 Shareholders following completion of the Public Offer prior to the Shares commencing trading on ASX.

5.13 Restricted Securities

Subject to the Company being admitted to the Official List and completing the Offers, certain Securities may be classified by the ASX as restricted securities and will be required to be held in escrow for up to 24 months from the date of Official Quotation. During the period in which these Securities are prohibited from being transferred, trading in Shares may be less liquid which may impact on the ability of a Shareholder to dispose of Shares in a timely manner.

None of the Shares issued under the Public Offer will be subject to escrow. The Company anticipates that the Securities issued under the Secondary Offers will be subject to escrow for a period of 24 months from the date of Official Quotation of the Company's Shares.

The number of Securities that are subject to ASX imposed escrow are at the ASX's discretion in accordance with the ASX Listing Rules and underlying policy.

The Company will announce to the ASX full details (quantity and duration) of the Securities required to be held in escrow prior to the Shares commencing trading on the ASX (which admission is subject to the ASX's discretion and approval).

The Company confirms its 'free float' (the percentage of the Shares that are not restricted and are held by Shareholders who are not related parties (or their associates) of the Company at the time of Admission) will be not less than 20% in compliance with ASX Listing Rule 1.1 Condition 7.

5.14 Dividend policy

Payment of dividends by the Company is at the discretion of the Board. Given the stage of development of the Company, the Board anticipates that significant expenditure will be incurred in the evaluation and development of the Company's Projects. These activities, together with the possible acquisition of interests in other projects, are expected to dominate at least, the first two-year period following the Company's Admission. Accordingly, the Directors have no current intention to declare and pay a dividend, and no dividends are expected to be paid during the foreseeable future following the Company's listing on the ASX.

In determining whether to declare future dividends the Directors and will consider the level of earnings of the Company, the operating results and overall financial condition of the Company, future capital requirements, capital management initiatives, general business outlook and other factors the Directors may consider relevant at the time of their decision.

The Directors cannot and do not provide any assurances in relation to the future payment of dividends or the level of franking credits attaching to dividends can be given by the Company.

5.15 Additional Information

Prospective investors are referred to and encouraged to read in its entirety both the:

(a) the Independent Technical Specialist's Report in Annexure A for further details about the Projects;

(b) the Solicitor's Report on Title in Annexure B for further details in respect to the Company's interests in the Projects; and

(c) the Independent Limited Assurance Report in Annexure C for further details on the Company's financials.

6. FINANCIAL INFORMATION

6.1 Introduction

This Section sets out the Historical Financial Information of the Company and its subsidiary, Tetragon Energy (Philippines) Pty Ltd (**Tetragon Philippines**) (together the **Group**), as well as the Pro Forma Historical Financial Information of the Group (together the **Financial Information**). The Directors are responsible for the inclusion of the Financial Information in this Prospectus. The purpose of the inclusion of the Pro Forma Financial Historical Information is to illustrate the effects of the Offers and other material transactions of the Group.

HLB Mann Judd has prepared an Independent Limited Assurance Report in respect of the Financial Information, as set out in Annexure C. Investors should note the scope and limitations of the Independent Limited Assurance Report.

The Financial Information and Independent Limited Assurance Report should be read in conjunction with the other information contained in this Prospectus, including:

(a) the risk factors described in Section 7;

(b) the use of funds described in Section 5.8;

(c) the indicative capital structure described in Section 5.10; and

(d) the Independent Limited Assurance Report set out in Annexure C.

Investors should also note that past performance is not an indication of future performance of the Group.

The functional and presentation currency of the Group for all financial information presented is $A. The functional currency of the subsidiary, Tetragon Philippines is $US. All financial information of this subsidiary has been translated into the Group's presentation currency.

6.2 Forecast financial information

Oil and gas exploration (including petroleum exploration) is inherently uncertain. Consequently, there are significant uncertainties associated with forecasting future revenues and expenses of the Group. In light of uncertainty as to timing and outcome of the Group's growth strategies and the general nature of the industry in which the Group operates, as well as uncertain macro market and economic conditions in their markets, the Group's performance in any future period cannot be reliably estimated. On these bases and after considering *ASIC Regulatory Guide 170*, the Directors do not believe they have a reasonable basis to reliably forecast future earnings and accordingly forecast financials are not included in this Prospectus.

The Financial Information is presented in an abbreviated form insofar as it does not include all the disclosures, statements, comparative information and notes required in an annual financial report prepared in accordance with Australian Accounting Standards applicable to general purpose financial reports prepared in accordance with the Corporations Act.

6.3 Basis of preparation of the Historical Financial Information

The Historical Financial Information included in this Section 6 has been prepared in accordance with the recognition and measurement principles of Australian Accounting Standards (including the Australian Accounting Interpretations) adopted by the Australian Accounting Standards Board and the Corporations Act. The Historical Financial Information is presented in an abbreviated form insofar as it does not include all the presentation, disclosures, statements or comparative information as required by Australian Accounting Standards applicable to annual financial reports prepared in accordance with the Corporations Act. Material accounting policies applied to the Historical Financial Information are set out in Section 6.10 under the heading 'Material Accounting Policies'.

The Historical Financial Information of the Group comprises:

(a) the historical Consolidated Statement of Profit or Loss and Other Comprehensive Income for the period from the Company's incorporation, 6 February 2025 to 31 March 2026;

(b) the historical Consolidated Statement of Cash Flows for the period from the Company's incorporation, 6 February 2025 to 31 March 2026; and

(c) the historical Consolidated Statement of Financial Position as at 31 March 2026,

(together the **Historical Financial Information**).

The Historical Financial Information has been reviewed by HLB Mann Judd as part of their role as Investigating Accountants and pursuant to the preparation of their Independent Limited Assurance Report as set out in Annexure C.

The Historical Financial Information has been prepared for the purpose of the Prospectus.

6.4 Basis of preparation of the Pro Forma Financial Information

The Pro Forma Financial Information comprises:

(a) the Pro Forma Consolidated Statement of Financial Position of the Group as at 31 March 2026, prepared on the basis that the pro forma adjustments and subsequent events had occurred as at 31 March 2026; and

(b) the Notes to the Pro Forma Consolidated Statement of Financial Position,

(together, the **Pro Forma Financial Information**).

The Pro Forma Financial Information included in this Section 6 has been prepared for the purposes of inclusion in this Prospectus. The Pro Forma Financial Information is based on the reviewed Statement of Financial Position of the Group as at 31 March 2026 and adjusting for the impacts of the Offers and other pro forma adjustments.

The Pro Forma Financial Information does not reflect the actual financial results of the Group for the period indicated. The directors of the Company believe that it provides useful information as it illustrates to investors the financial position of the Group immediately after the Offers are completed and related subsequent events adjustments and pro forma adjustments are made.

6.5 Historical Consolidated Statement of Profit or Loss and Other Comprehensive Income

The table below presents the Historical Consolidated Statement of Profit or Loss and Other Comprehensive Income for the Group for the period from the Company's incorporation, 6 February 2025 to 31 March 2026.

		Period ended 31 March 2026 Reviewed $
Income		-
Administration expenses		(9,329)
Loss before income tax		**(9,329)**
Other comprehensive income		-
Total comprehensive loss		**(9,329)**

6.6 Historical Consolidated Statement of Cash Flows

The table below presents the Historical Consolidated Statement of Cash Flows for the Group for the period from the Company's incorporation, 6 February 2025 to 31 March 2026.

	Period ended 31 March 2026 Reviewed $
Cash Flows from Operating Activities	**-**
Net cash from/(used in) operating activities	**-**
Cash flows from investing activities	
Advance to Triangle Energy (Global) Limited as collateral for performance bond	(500,000)
Net cash used in investing activities	**(500,000)**
Cash flows from financing activities	
Loan from Triangle Energy (Global) Limited	1,545,209
Net cash provided by financing activities	**1,545,209**
Net increase in cash and cash equivalents held	**1,045,209**
Cash and cash equivalents at beginning of the period	-
Effect of exchange rate fluctuations on cash held	(496)
Cash and cash equivalents at end of the period	**1,044,713**

6.7 Historical Consolidated Statement of Financial Position

The table below presents the Historical Consolidated Statement of Financial Position for the Group as at 31 March 2026.

		31 March 2026 Reviewed $
Current Assets		
Cash and cash equivalents		1,044,713
Other receivable		500,000
Other		100
Total Current Assets		**1,544,813**
Non-Current Assets		
Exploration and evaluation expenditure		537,262
Total Non-Current Assets		**537,262**
Total Assets		**2,082,075**
Current Liabilities		
Other payables		329
Borrowings – Triangle Energy (Global) Limited		2,091,471

		31 March 2026 Reviewed $
Total Current Liabilities		**2,091,800**
Total Liabilities		**2,091,800**
Net Liabilities		**(9,725)**
Equity		
Issued capital		100
Foreign currency translation reserve		(496)
Accumulated losses		(9,329)
Total Equity/(Deficiency)		**(9,725)**

6.8 Pro Forma Consolidated Statement of Financial Position

The table below sets out the adjustments relating to subsequent events and pro forma adjustments that have been incorporated into the Pro Forma Consolidated Statement of Financial Position as at 31 March 2026.

The subsequent events reflect the material transactions that have occurred since 31 March 2026. The pro forma adjustments include the financial impact of the Offers.

The Pro Forma Consolidated Statement of Financial Position is provided for illustrative purposes only and should be read in conjunction with the notes below.

	Ref	31 Mar 2026 Reviewed	Subsequent events adjustments	Pro forma adjustments	Pro forma Reviewed
		$	$	$	$
ASSETS					
CURRENT ASSETS					
Cash and cash equivalents	6.11	1,044,713	-	3,372,718	4,417,431
Other receivable	6.12	500,000	-	-	500,000
Other		100	-	-	100
TOTAL CURRENT ASSETS		**1,544,813**	**-**	**3,372,718**	**4,917,531**
NON-CURRENT ASSETS					
Exploration and evaluation expenditure	6.13	537,262	-	-	537,262
TOTAL NON-CURRENT ASSETS		**537,262**	**-**	**-**	**537,262**
TOTAL ASSETS		**2,082,075**	**-**	**3,372,718**	**5,454,793**
LIABILITIES					
CURRENT LIABILITIES					

	Ref	31 Mar 2026 Reviewed	Subsequent events adjustments	Pro forma adjustments	Pro forma Reviewed
		$	$	$	$
Other payables		329	-	-	329
Borrowings – Triangle Energy (Global) Limited	6.14	2,091,471	(2,091,471)	-	-
TOTAL CURRENT LIABILTIES		**2,091,800**	**(2,091,471)**	**-**	**329**
TOTAL LIABILITIES		**2,091,800**	**(2,091,471)**	**-**	**329**
NET ASSETS/(LIABILITIES)		**(9,725)**	**2,091,471**	**3,372,718**	**5,454,464**
EQUITY					
Issued capital	6.15	100	2,091,471	3,579,572	5,671,143
Share-based payment reserve	6.16	-	-	293,195	293,195
Foreign exchange translation reserve		(496)	-	-	(496)
Accumulated losses	6.17	(9,329)	-	(500,049)	(509,378)
TOTAL EQUITY/(DEFICIENCY)		**(9,725)**	**2,091,471**	**3,372,718**	**5,454,464**

6.9 Notes to the Pro Forma Consolidated Statement of Financial Position

Subsequent events adjustments

(a) The issue of 19,700,308 fully paid shares in the Company to Triangle on 4 May 2026 in full satisfaction of the loan owing by the Company to Triangle of $2,091,471 as at 31 March 2026.

Pro forma adjustments

(a) The issue of 20,000,000 fully paid shares at an issue price of $0.20 each, amounting to $4,000,000 under the Public Offer.

(b) The issue of 1,250,000 Options under the Advisor Offer to Salient Corporate (or its nominee) for corporate advisory services. These options are exercisable at $0.30 and will expire on the date that is three years from the date of issue. The options have been valued at $112,767 and have been expensed to profit or loss. Refer to Section 6.17 for details on the assumptions used in valuing these options.

(c) The issue of 2,000,000 Options under the Lead Manager Offer to Powerhouse (or its nominee) for acting as Lead Manager of the Public Offer. These Options are exercisable at $0.30 and will expire on the date that is four years from the date of issue. The options have been valued at $180,428 and have been applied against capital raised. Refer to Section 6.17 for details on the assumptions used in valuing these Options.

(d) The issue of 3,900,000 Performance Rights to certain Directors and consultants as part of their respective remuneration packages. Refer to Section 6.18 for further details.

(e) Total anticipated expenses associated with the Public Offer estimated to be $627,282 (exclusive of GST). A full breakdown of the anticipated costs of the Public Offer costs is as follows:

	$
Broker fees	240,000
Investigating accountant fees	20,000
Technical reports	120,000
Legal fees	125,000
Financial accounting consultant	10,000
ASX fees	84,076
ASIC lodgement fees	3,206
Other	25,000
Total	**627,282**
Expensed to profit and loss	387,282
Applied against capital raised	240,000
Total	**627,282**

6.10 Material Accounting Policies

6.10.1 Basis of preparation of Historical Financial Information and Pro Forma Financial Information

The Historical Financial Information and Pro Forma Financial Information have been prepared in accordance with the measurement requirements (but not all of the disclosure requirements) of applicable Australian Accounting Standards and Interpretations and other mandatory professional reporting requirements in Australia using the accrual basis of accounting and the historical cost convention. The financial information complies with Australian Accounting Standards, which include Australian equivalents to International Financial Reporting Standards (**AIFRS**). Compliance with AIFRS ensures that the financial information, comprising the financial statements and notes thereto, comply with measurement requirements but not all of the disclosure requirements of International Financial Reporting Standards.

The accounting policies detailed below have been consistently applied throughout the period presented unless otherwise stated.

The Financial Information has been prepared on an accruals basis and is based on historical costs, modified, where applicable, by the measurement at fair value of selected non-current assets, financial assets and financial liabilities.

6.10.2 Adoption of new and revised standards

The Directors have reviewed all of the new and revised Standards and Interpretations issued by the AASB that are relevant to the Group's operations and effective for future reporting periods. It has been determined by the Directors that AASB 18 *Presentation and Disclosure in Financial Statements*, which is effective for annual reporting periods commencing on or after 1 January 2027, will affect disclosures in future financial reports, however the Company has not yet assessed the impact of this standard.

6.10.3 Going concern

The Historical Financial Information has been prepared on a going concern basis, which contemplates the continuity of normal business activity and the realisation of assets and the settlement of liabilities in the normal course of business. The Directors have made this assessment based on the Offers being completed, in which case funds of $4,000,000 will be raised (before costs).

6.10.4 Basis of consolidation

The consolidated Historical Financial Information of the Group comprise the financial statements of the Company and its controlled entity, Tetragon Philippines.

In preparing the consolidated Historical Financial Information, all intercompany balances and transactions, income and expenses and profit and losses resulting from intra-group transactions have been eliminated in full.

Subsidiaries are fully consolidated from the date on which control is transferred to the Group and cease to be consolidated from the date on which control is transferred out of the Group. Control exists where the Group has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. The existence and effect of potential voting rights that are currently exercisable or convertible are considered when assessing when the Group controls another entity.

Unrealised gains or transactions between entities in the Group are eliminated to the extent of the Group's interests in the subsidiaries. Unrealised losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred. Accounting policies of the subsidiary have been changed where necessary to ensure consistency with the policies adopted by the Group.

When the Group loses control of a subsidiary, a gain or loss is recognised in profit or loss and is calculated as the difference between (i) the aggregate of the fair value of the consideration received and the fair value of any retained interest and (ii) the previous carrying amount of the assets (including goodwill) and liabilities of the subsidiary and any non-controlling interests. When assets of the subsidiary are carried at revalued amounts or fair values and the related cumulative gain or loss has been recognised in other comprehensive income and accumulated in equity, the amounts previously recognised in other comprehensive income and accumulated in equity are accounted for as if the Group has directly disposed of the relevant assets (i.e. reclassified to profit or loss or transferred directly to retained earnings as specified by applicable Standards). The fair value of any investment retained in the former subsidiary at the date when control is lost is regarded as the fair value on initial recognition for subsequent accounting or, when applicable, the cost on initial recognition of an investment in an associate or jointly controlled entity.

6.10.5 Income tax

The income tax expense or benefit for the period is the tax payable on the current period's taxable income based on the applicable income tax rate for each jurisdiction adjusted by changes in deferred tax assets and liabilities attributable to temporary differences and to unused tax losses.

Current tax assets and liabilities for the current and prior periods are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted or substantively enacted by the balance date.

Deferred income tax is provided on all temporary differences at the balance date between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes.

Deferred income tax liabilities are recognised for all taxable temporary differences except:

(a) when the deferred income tax liability arises from the initial recognition of goodwill or of an asset or liability in a transaction that is not a business combination and that, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss; or

(b) when the taxable temporary difference is associated with investments in subsidiaries, associates or interests in joint ventures, and the timing of the reversal of the temporary difference can be controlled and it is probable that the temporary difference will not reverse in the foreseeable future.

Deferred income tax assets are recognised for all deductible temporary differences, carry-forward of unused tax assets and unused tax losses, to the extent that it is probable that taxable profit will be available against which the deductible temporary differences and the carry-forward of unused tax credits and unused tax losses can be utilised, except:

(a) when the deferred income tax asset relating to the deductible temporary difference arises from the initial recognition of an asset or liability in a transaction

that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss; or

(b) when the deductible temporary difference is associated with investments in subsidiaries, associates or interests in joint ventures, in which case a deferred tax asset is only recognised to the extent that it is probable that the temporary difference will reverse in the foreseeable future and taxable profit will be available against which the temporary difference utilised.

The carrying amount of deferred income tax assets is reviewed at each balance date and reduced to the extent that it is no longer probable that sufficient taxable profit will be available to allow all or part of the deferred income tax asset to be utilised.

Unrecognised deferred income tax assets are reassessed at each balance date and are recognised to the extent that it has become probable that future taxable profit will allow the deferred tax asset to be recovered.

Deferred income tax assets and liabilities are measured at the tax rates that are expected to apply to the year when the asset is realised or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the balance date.

Income taxes relating to items recognised directly in equity are recognised in equity and not in profit or loss.

Deferred tax assets and deferred tax liabilities are offset only if a legally enforceable right exists to set off current tax assets against current tax liabilities and the deferred tax assets and liabilities relate to the same taxable entity and the same taxation authority.

6.10.6 Cash and cash equivalents

Cash comprises cash at bank and in hand. Cash equivalents are short term, highly liquid investments that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value.

For the purposes of the Statement of Cash Flows, cash and cash equivalents consist of cash and cash equivalents as described above, net of outstanding bank overdrafts.

6.10.7 Other receivables

Other receivables are measured on initial recognition at fair value and are subsequently measured at amortised cost using the effective interest rate method, less any allowance for expected credit loss.

6.10.8 Foreign currency translation

The functional and presentation currency of the Company and its subsidiary is Australian dollars.

Transactions in foreign currencies are initially recorded in the functional currency by applying the exchange rates ruling at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are retranslated at the rate of exchange ruling at the balance date.

All exchange differences are taken to profit or loss with the exception of differences on foreign currency borrowings that provide a hedge against a net investment in a foreign entity. These are taken directly to equity until the disposal of the net investment, at which time they are recognised in profit or loss.

Tax charges and credits attributable to exchange differences on those borrowings are also recognised in equity.

Non-monetary items that are measured in terms of historical cost in a foreign currency are translated using the exchange rate as at the date of the initial transaction. Non-monetary items measured at fair value in a foreign currency are translated using the exchange rates at the date when the fair value was determined.

At the reporting date, the assets and liabilities of foreign subsidiaries are translated into the presentation currency of the Company at the exchange rate on that date. The exchange

differences arising on the translation are taken directly to a separate component of equity and recognised in the foreign currency translation reserve.

6.10.9 Impairment of assets

The Group assesses at each reporting date whether there is an indication that an asset may be impaired. If any such indication exists, or when annual impairment testing for an asset is required, the Group makes an estimate of the asset's recoverable amount. An asset's recoverable amount is the higher of its fair value less costs to sell and its value in use and is determined for an individual asset, unless the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets and the asset's value in use cannot be estimated to be close to its fair value. In such cases the asset is tested for impairment as part of the cash-generating unit to which it belongs. When the carrying amount of an asset or cash-generating unit exceeds its recoverable amount, the asset or cash-generating unit is considered impaired and is written down to its recoverable amount.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Impairment losses relating to continuing operations are recognised in those expense categories consistent with the function of the impaired asset unless the asset is carried at revalued amount (in which case the impairment loss is treated as a revaluation decrease).

An assessment is also made at each reporting date as to whether there is any indication that previously recognised impairment losses may no longer exist or may have decreased. If such indication exists, the recoverable amount is estimated. A previously recognised impairment loss is reversed only if there has been a change in the estimates used to determine the asset's recoverable amount since the last impairment loss was recognised. If that is the case the carrying amount of the asset is increased to its recoverable amount. That increased amount cannot exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognised for the asset in prior years. Such reversal is recognised in profit or loss unless the asset is carried at revalued amount, in which case the reversal is treated as a revaluation increase. After such a reversal the depreciation charge is adjusted in future periods to allocate the asset's revised carrying amount, less any residual value, on a systematic basis over its remaining useful life.

6.10.10 Other payables

Other payables are carried at amortised cost and represent liabilities for goods and services provided to the Group prior to the end of the financial year that are unpaid and arise when the Group becomes obliged to make future payments in respect of the purchase of these goods and services. Other payables are presented as current liabilities unless payment is not due within 12 months.

6.10.11 Provisions

Provisions are recognised when the Group has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Provisions are not recognised for future operating losses.

When the Group expects some or all of a provision to be reimbursed, for example under an insurance contract, the reimbursement is recognised as a separate asset but only when the reimbursement is virtually certain. The expense relating to any provision is presented in the Statement of Profit or Loss and Other Comprehensive Income net of any reimbursement.

Provisions are measured at the present value or management's best estimate of the expenditure required to settle the present obligation at the end of the reporting period.

If the effect of the time value of money is material, provisions are discounted using a current pre-tax rate that reflects the risks specific to the liability.

When discounting is used, the increase in the provision due to the passage of time is recognised as an interest expense.

Restoration of exploration and operating locations

Provision is made for the obligation to restore exploration and operating locations. The provision is first recognised in the period in which the obligations arise. The nature of the restoration activities includes the removal of facilities, abandonment of wells and restoration of affected areas.

Restoration provisions are updated periodically, with a corresponding movement recognised against the related exploration and evaluation asset or oil and gas properties.

Over time, the liability is increased for a change in the present value based on a pre-tax discount rate appropriate to the risk inherent in the liability. The unwinding of the discount is recorded as an accretion charge within finance costs. The carrying amount capitalised in oil and gas properties is depreciated over the useful life of the asset (based on the production profile).

6.10.12 Issued capital

Ordinary shares are classified as equity. Incremental costs directly attributable to the issue of new shares or options are shown in equity as a deduction, net of tax, from the proceeds.

6.10.13 Financial instruments

Recognition and de-recognition

Financial assets and financial liabilities are recognised when the Group becomes a party to the contractual provisions of the financial instrument.

Financial assets are derecognised when the contractual rights to the cash flows from the financial asset expire, or when the financial asset and substantially all the risks and rewards are transferred.

A financial liability is derecognised when it is extinguished, discharged, cancelled or expires.

6.10.14 Share-based payment transactions

Equity settled transactions:

The Group provides benefits to employees (including senior executives) of the Group in the form of share-based payments, whereby employees and consultants render services in exchange for shares or rights over shares (equity-settled transactions).

When provided, the cost of these equity-settled transactions with employees and consultants, where the fair value of the services is not readily determinable, is measured by reference to the fair value of the equity instruments at the date at which they are granted. The fair value is determined by an external valuer using a binomial model.

In valuing equity-settled transactions, no account is taken of any performance conditions, other than conditions linked to the price of the shares of the Company (market conditions) if applicable.

The cost of equity-settled transactions is recognised, together with a corresponding increase in equity, over the period in which the performance and/or service conditions are fulfilled, ending on the date on which the relevant employees become fully entitled to the award (the vesting period).

The cumulative expense recognised for equity-settled transactions at each reporting date until vesting date reflects (i) the extent to which the vesting period has expired and (ii) the Group's best estimate of the number of equity instruments that will ultimately vest. No adjustment is made for the likelihood of market performance conditions being met as the effect of these conditions is included in the determination of fair value at grant date. The Statement of Profit or Loss and Other Comprehensive Income charge or credit for a period represents the movement in cumulative expense recognised as at the beginning and end of that period.

No expense is recognised for awards that do not ultimately vest, except for awards where vesting is only conditional upon a market condition.

If the terms of an equity-settled award are modified, as a minimum an expense is recognised as if the terms had not been modified. In addition, an expense is recognised for any modification that increases the total fair value of the share-based payment arrangement, or is otherwise beneficial to the employee, as measured at the date of modification.

If an equity-settled award is cancelled, it is treated as if it had vested on the date of cancellation, and any expense not yet recognised for the award is recognised immediately. However, if a new award is substituted for the cancelled award and designated as a replacement award on the date that it is granted, the cancelled and new award are treated as if they were a modification of the original award, as described in the previous paragraph.

The dilutive effect, if any, of outstanding options is reflected as additional share dilution in the computation of earnings per share.

6.10.15 Exploration and evaluation expenditure

Exploration and evaluation expenditures in relation to each separate area of interest are recognised as an exploration and evaluation asset in the year in which they are incurred where the following conditions are satisfied:

(a) the rights to tenure of the area of interest are current; and

(b) at least one of the following conditions is also met:

(i) the exploration and evaluation expenditures are expected to be recouped through successful development and exploration of the area of interest, or alternatively, by its sale; or

(ii) exploration and evaluation activities in the area of interest have not at the reporting date reached a stage which permits a reasonable assessment of the existence or otherwise of economically recoverable reserves, and active and significant operations in, or in relation to, the area of interest are continuing.

Exploration and evaluation assets are initially measured at cost and include acquisition of rights to explore, studies, exploratory drilling, trenching and sampling and associated activities and an allocation of depreciation and amortised of assets used in exploration and evaluation activities. General and administrative costs are only included in the measurement of exploration and evaluation costs where they are related directly to operational activities in a particular area of interest.

Exploration and evaluation assets are assessed for impairment when facts and circumstances suggest that the carrying amount of an exploration and evaluation asset may exceed its recoverable amount. The recoverable amount of the exploration and evaluation asset (for the cash generating unit(s) to which it has been allocated being no larger than the relevant area of interest) is estimated to determine the extent of the impairment loss (if any). Where an impairment loss subsequently reverses, the carrying amount of the asset is increased to the revised estimate of its recoverable amount, but only to the extent that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss been recognised for the asset in previous years. Where a decision has been made to proceed with development in respect of a particular area of interest, the relevant exploration and evaluation asset is tested for impairment and the balance is then reclassified to development.

6.10.16 Development expenditure

Development expenditure is recognised at cost less accumulated amortisation and any impairment losses. Exploration and evaluation expenditure is reclassified to development expenditure once the technical feasibility and commercial viability of extracting the related petroleum resource is demonstrable. Where commercial production in an area of interest has commenced, the associated costs together with any forecast future capital expenditure necessary to develop proved and probable reserves are amortised over the estimated economic life of the mine on a units-of-production basis.

6.10.17 Oil & gas properties

Oil & gas properties are stated as cost less accumulated depreciation and impairment charge (unless they have been acquired as part of a business combination). Oil & gas properties include initial cost to acquire, construct, install or complete production and infrastructure facilities such as pipelines and platforms, transfers from exploration and evaluation assets, development of wells and estimates of costs for dismantling and restoring sites.

Subsequent capital costs, including major maintenance, are included in the asset's carrying value only when it is probable that future economic benefits associated with the item will flow to the Group and the costs can be reliably measured.

Oil & gas properties (including all categories within the classification) are depreciated to their estimated residual value at a rate based on their expected useful lives with reference to the unit of production basis over proven reserves or proven plus probable.

6.10.18 Critical accounting judgements and key sources of estimation uncertainty

The application of accounting policies requires the use of judgements, estimates and assumptions about carrying values of assets and liabilities that are not readily apparent from other sources. The estimates and associated assumptions are based on historical experience and other factors that are considered to be relevant. Actual results may differ from these estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions are recognised in the period in which the estimate is re vised if it effects only that period, or in the period of the revision and future periods if the revision affects both current and future periods.

Share-based payment transactions

The Group measures the cost of equity-settled transactions with employees, consultants and advisors, where the fair value of the services is not readily determinable, by reference to the fair value of the equity instruments at the date at which they are granted. The fair value of the instruments is determined using either a Black & Scholes or Monte Carlo model based on certain assumptions at the date at which they are granted.

6.10.19 Cash and cash equivalents

The reviewed pro forma cash and cash equivalents balance is set out below:

	Ref	$
Reviewed cash and cash equivalents as at 31 March 2026		1,044,713
Pro forma adjustments:		
Proceeds from shares issued under the Public Offer	6.9(b)	4,000,000
Public Offer costs	6.9(f)	(627,282)
Pro forma cash and cash equivalents		**4,417,431**

6.11 Other receivable

The reviewed pro forma other receivable balance is set out below:

		$
Reviewed other receivable as at 31 March 2026		500,000
Pro forma adjustments		-
Pro forma other receivable		**500,000**

The other receivable balance comprises funding of $500,000 (**Security Funding**) deposited into a KD Legal Law Practice trust account which, together with similar funding of $500,000

provided by Winchester, allowed Triangle to establish a $1,000,000 collateral financing facility with Westpac Banking Corporation (**Westpac**) whereby Westpac arranged a $US500,000 performance bond issued to Bank Negara Indonesia in relation to a Joint Study Agreement in Indonesia. A Joint Study in Indonesia is a pre-licensing arrangement coordinated by SKK Migas, which will allow Triangle to evaluate open acreage before it is offered under a Petroleum Sharing Contract (PSC) bid round. The Security Funding deposited into the KD Legal Law Practice trust account will be held pending release in accordance with the release provisions contained in the Amended and Restated Binding Term Sheet dated 15 May 2026 between Triangle, the Company and Winchester. The Company, Triangle and Winchester will fund the Joint Study in proportion to the agreed working interests, being Triangle 51% (operator), the Company 24.5% and Winchester 24.5%. The Company and Winchester will each have an option to acquire a 24.5% interest in any petroleum licence or PSC awarded to Triangle over the study area.

6.12 Exploration and evaluation expenditure

The reviewed pro forma exploration and evaluation expenditure balance is set out below:

		$
Reviewed exploration and evaluation expenditure as at 31 March 2026		537,262
Pro forma adjustments		-
Pro forma exploration and evaluation expenditure		**537,262**

The ultimate recoupment of the expenditure is dependent upon the successful development and commercial exploitation or, alternatively, sale of the respective areas of interest.

6.13 Borrowings – Triangle

The reviewed pro forma borrowings balance is set out below:

	Ref	$
Reviewed borrowings as at 31 March 2026		2,091,471
Subsequent events adjustments:		
Issue of 19,700,308 fully paid shares in the Company to Triangle Energy (Global) Limited on 4 May 2026 in full satisfaction of this loan owing to Triangle Energy (Global) Limited of $2,091,471 as at 31 March 2026	6.9(a)	(2,091,471)
Pro forma adjustments:		-
Pro forma borrowings		**-**

6.14 Issued capital

The reviewed pro forma issued capital balance is set out below:

	Ref		
		No. of shares	$
Reviewed issued capital as at 31 March 2026		100	100
Subsequent events adjustments:			
Issue of 19,700,308 fully paid shares in the Company to Triangle Energy (Global) Limited on 4 May 2026 in full satisfaction of this loan owing to Triangle Energy (Global) Limited of $2,091,471 as at 31 March 2026	6.9(a)	19,700,308	2,091,471

Pro forma adjustments:			
Issue under the Public Offer	6.9 (b)	20,000,000	4,000,000
Options issued to Lead Manager applied against issued capital	6.9 (d)	-	(180,428)
Cash costs associated with the Public Offer applied against issued capital	6.9(f)	-	(240,000)
Pro forma issued capital		**39,700,408**	**5,671,143**

6.15 Share-based payment reserve

The reviewed pro forma share-based payment reserve balance is set out below:

Share-based payment reserve	Ref	$
Reviewed share-based payment reserve as at 31 March 2026		-
Pro Forma adjustments:		
Issue of 1,250,000 Options to Advisor	6.9(c) & 6.18	112,767
Issue of 2,000,000 Options to Lead Manager	6.9(d) & 6.18	180,428
Pro forma share-based payment reserve		**293,195**

6.16 Accumulated losses

The reviewed pro forma accumulated losses balance is set out below:

	Ref	$
Reviewed accumulated losses as at 31 March 2026		(9,329)
Pro forma adjustments:		
Options issued to Advisor expensed	6.9(c)	(112,767)
Public Offer costs expensed	6.9(f)	(387,282)
Pro forma accumulated losses		**(509,378)**

6.17 Share-based payments - Options

Under the Advisor Offer, 1,250,000 Options will be issued to Salient Corporate (or its nominee) for corporate advisory services. These Options are exercisable at $0.30 and will expire on the date that is three years from the date of issue. The Options have been valued at $112,767 using a Black & Scholes option pricing model and this value has been expensed to profit or loss.

Under the Lead Manager Offer, 2,000,000 Options will be issued to Powerhouse (or its nominee) for acting as Lead Manager of the Public Offer. These Options are exercisable at $0.30 and will expire on the date that is four years from the date of issue. The Options have been valued at $180,428 using a Black & Scholes option pricing model and this value has been applied against capital raised.

The assumptions used in the valuation of these Options are as follows:

	Advisor Options	Lead Manager Options
Valuation date	Date of prospectus	Date of prospectus
Expiry date	3 years from date of issue	4 years from date of issue

Spot price (Public Offer issue price)	$0.20	$0.20
Exercise price	$0.30	$0.30
Risk free rate	4.643%	4.643%
Volatility	80.75%	80.75%
Dividend yield	-	-
Fair value per option (rounded)	$0.09	$0.09
Total value	**$112,767**	**$180,428**

6.18 Share-based payments – Performance Rights

(a) The Company has agreed to issue a total of 3,900,000 Performance Rights to certain Directors and consultants as part of their respective remuneration packages as follows.

RECIPIENT	CLASS A	CLASS B	CLASS C	TOTAL
Conrad Todd	480,000	360,000	360,000	1,200,000
Greg Hancock	360,000	270,000	270,000	900,000
Mike Collins	280,000	210,000	210,000	700,000
Marvin Chan	220,000	165,000	165,000	550,000
Rory McGoldrick	220,000	165,000	165,000	550,000
Total	**1,560,000**	**1,170,000**	**1,170,000**	**3,900,000**

(b) The Performance Rights shall vest on the achievement of each of the following Vesting Conditions and each Performance Right shall otherwise expire on the following Expiry Dates:

CLASS	NUMBER	VESTING CONDITION	EXPIRY DATE
A	1,560,000	The Company's net resources increasing by 25%, as independently certified by a Competent Person in accordance with the Petroleum Resources Management System (PRMS), on or before 31 December 2026.	31 August 2027
B	1,170,000	Either of the following conditions being satisfied on or before 31 December 2026: the Company entering into a binding agreement to acquire a new project or asset, or the Company entering into a binding farm-out agreement in respect of an existing project or tenement, in each case on terms satisfactory to the Board; or the Company's volume weighted average share price calculated over any 15 consecutive ASX trading days on which the Company's shares are traded equalling or exceeding $0.40.	31 August 2027
C	1,170,000	No material environmental incidents and no Lost Time Injuries having been recorded in connection with the	31 August 2027

CLASS	NUMBER	VESTING CONDITION	EXPIRY DATE
		Company's operations during the period from the date of issue to 31 December 2026.	
Total	**3,900,000**		

Value of Performance Rights:

The Class A and Class C Performance Rights have non-market based vesting conditions. As a result, they have been valued at the Public Offer issue price of $0.20 per right, with a total value of $546,000.

The Class B Performance Rights contain both a market-based vesting condition and a non-market based vesting condition. As a result, these Performance Rights have been valued using a Monte Carlo valuation methodology using the following assumptions:

Valuation date	Date of prospectus
End of vesting period	31 December 2026
Expiry date	31 August 2027
Spot price (Public Offer issue price)	$0.20
Exercise price	Nil
VWAP hurdle	$0.40
Risk-free rate	4.538%
Volatility	80.75%
Dividend yield	-
Fair value per security (rounded)	$0.0632
Total value	**$73,944**

The total value of all classes of Performance Rights has not been recorded in the Pro Forma Financial Information as the Directors are unable at this early stage to assess whether it is probable that the respective vesting conditions will be met.

7. RISK FACTORS

7.1 Introduction

The Securities offered under this Prospectus should be considered as highly speculative and an investment in the Company is not risk free.

The future performance of the Company and the value of the Shares may be influenced by a range of factors, many of which are largely beyond the control of the Company and the Directors. The key risks that have a direct influence on the Company, its Projects and activities are set out in Section 3. Those key risks as well as other risks associated with the Company's business, the industry in which it operates and general risks applicable to all investments in listed securities and financial markets generally are described below.

The risks factors set out in this Section 7, and other risk factors not specifically referred to, may have a materially adverse impact on the performance of the Company and the value of the Shares. This Section 7 is not intended to provide an exhaustive list of the risk factors to which the Company is exposed.

The Directors strongly recommend that prospective investors consider the risk factors set out in this Section 7, together with all other information contained in this Prospectus.

Before determining whether to invest in the Company you should ensure that you have a sufficient understanding of the risks described in this Section 7 and all of the other information set out in this Prospectus and consider whether an investment in the Company is suitable for you, taking into account your objectives, financial situation and needs.

If you do not understand any matters contained in this Prospectus or have any queries about whether to invest in the Company, you should consult your accountant, financial adviser, stockbroker, lawyer or other professional adviser.

7.2 Company specific risks

RISK CATEGORY	RISK
Conditional Prospectus	This Prospectus is conditional upon the Conditions being satisfied or waived. The Conditions are set out in Section 4.8. There is no certainty that the Conditions will be satisfied. In the event that these Conditions are not met then the listing of the Company on ASX will not proceed, and all application monies received will be returned to applicants without interest.
Limited History	While the Company has been incorporated since 6 February 2025, during that time it has operated as a wholly owned subsidiary of Triangle. No assurance can be given that the Company will achieve commercial viability through the successful exploration of the Projects. Until the Company is able to realise value from its Projects, it is likely to incur ongoing operating losses.
Development and commercialisation of the Projects	The Company's future performance is significantly dependent on achieving milestones leading to the successful development of the Projects. Oil and gas projects, which includes petroleum exploration, are subject to a range of risks and uncertainties that may affect timing, costs and ultimate viability. Development activities can be delayed or disrupted by adverse weather, equipment failure, unexpected geological conditions, labour shortages, industrial action, cost inflation and supply chain constraints. The Company must also secure and maintain a variety of government approvals before commencing or expanding operations. Even if the development and commercialisation proceed in line with expectations, there is no assurance that the Projects will be commercially viable or capable of generating positive cash flow. Delays or cost overruns may materially impact the Company's financial position and its ability to fund ongoing operations. A failure to achieve key development milestones, or to do so on

RISK CATEGORY	RISK
	schedule and within budget, may adversely affect the Company's business, prospects and the value of its Shares.
Contractual risks – Joint Operating Agreement	The Company holds its 37.5% participating interests in SC-80 and SC-81 as part of a joint venture with Sunda Energy Plc, PXP Energy Corporation and Philodrill Corporation, to be governed by Joint Operating Agreements (**JOAs**). As a consequence of this joint venture structure, the Company's ability to advance exploration on SC-80 and SC-81 is dependent on the agreement and co-operation of its joint venture partners, and the Company may have limited ability to unilaterally determine the timing, scope or funding of operations on those permits. The Company will be the initial operator under the JOAs, however, under the proposed terms of the JOAs, there are provisions that could materially affect the Company's interests, including onerous default mechanisms under which a failure to meet cash call or payment obligations may result in the Company losing its entitlement to production, being excluded from decision-making, and ultimately having its participating interest transferred to the other joint venture parties at a price that may be materially below fair market value. The Company's operatorship of SC-80 and SC-81 may also be terminated by the other joint venture parties in certain circumstances, including material breach, insolvency or a change in control of the Company. Any deterioration in relations with joint venture partners, failure to agree on work programmes or budgets, or exercise of remedies by other parties under the JOAs could materially affect the Company's ability to progress, and ultimately retain its interests in, SC-80 and SC-81.
Permit renewal	The Company is required to comply with a range of laws to retain the Permits comprising the Projects and periodically apply to renew them. Each Permit also has its own specific work program and expenditure requirements that the Company must satisfy. There can be no assurance that any of the Permits will be renewed (or renewed on the same terms), or that the Company will be able to continue to meet all renewal conditions, work program obligations, or expenditure requirements. If a Permit is not renewed, is renewed subject to materially more onerous conditions, or is suspended, amended or cancelled, the Company's ability to continue exploration and/or development activities on the relevant Projects may be delayed, restricted or prevented, which could have a material adverse effect on the Projects and the Company's business, financial condition and results of operations. The extension of each service contract for a further period is conditional on the Company not being in default of its exploration work and other obligations and having provided an agreed work programme and budget for the extension period. There can be no assurance that these conditions will be satisfied or that extension will be granted on the same terms.
Climate risk	There are a number of climate-related factors that may affect the operations and proposed activities of the Company. The climate change risks particularly attributable to the Company include: (a) the emergence of new or expanded regulations associated with the transitioning to a lower-carbon economy and market changes related to climate change mitigation. The Company may be impacted by changes to local or international compliance regulations related to climate change mitigation efforts, or by specific taxation or penalties for carbon emissions or environmental damage. These examples sit amongst an array of possible restraints on industry that may further impact the Company and its profitability. While the Company will endeavour to manage these risks and limit any consequential impacts, there can be no guarantee

RISK CATEGORY	RISK
	that the Company will not be impacted by these occurrences; and (b) climate change may cause certain physical and environmental risks that cannot be predicted by the Company, including events such as increased severity of weather patterns and incidence of extreme weather events and longer-term physical risks such as shifting climate patterns. All these risks associated with climate change may significantly change the industry in which the Company operates.
Foreign Jurisdiction Risk – Philippines	The Company's operating activities will be subject to laws and regulations governing exploration of property, health and worker safety, employment standards, waste disposal, protection of the environment, land and water use, prospecting, taxes, labour standards, occupational health standards, toxic wastes, the protection of endangered and protected species and other matters. While the Company understands that it is in substantial compliance with all material current laws and regulations affecting its activities, future changes in applicable laws, regulations, agreements or changes in their enforcement or regulatory interpretation could result in changes in legal requirements or in the terms of existing permits and agreements applicable to the Company, its subsidiary or its properties, which could have a material adverse impact on the Company's current operations or planned development projects. Where required, obtaining necessary permits and licences can be a complex, time consuming process and the Company cannot be sure whether any necessary permits will be obtainable on acceptable terms, in a timely manner or at all. The costs and delays associated with obtaining necessary permits and complying with these permits and applicable laws and regulations could stop or materially delay or restrict the Company from proceeding with any future exploration or development of its properties. Any failure to comply with applicable laws and regulations or permits, even if inadvertent, could result in interruption or closure of exploration, development or other activities and could result in material fines, penalties or other liabilities. Adverse changes in Filipino government policies or legislation may affect ownership of oil and gas interests, taxation, royalties, land access, labour relations, and production and exploration activities of the Company. It is possible that the current system of exploration and drill permitting in the Philippines may change, resulting in impairment of rights and possibly expropriation of the Company's properties without adequate compensation. Under the Philippine law, all petroleum resources are owned by the State and cannot be alienated. The service contracts held by the Company confer operational rights only, subject to full control and supervision by the State. In addition, local government units in whose jurisdictions the contract areas fall are entitled under Philippine law to a share of revenues from the utilisation of natural resources. The extent and quantum of these local government revenue-sharing obligations have not yet been fully quantified and may impose additional costs on the Company. Furthermore, if any part of the contract areas is found to overlap with ancestral domain lands or areas designated as protected under the National Integrated Protected Areas System, additional approvals or legislative authority may be required before exploration activities can proceed in those areas.
Regulatory Risk	The oil and gas industry is subject to extensive regulation, covering areas such as exploration, drilling, production, environmental

RISK CATEGORY	RISK
	management, land access, health and safety, petroleum titles, pipelines, decommissioning, and rehabilitation. the Company is required to obtain, maintain, and comply with a range of approvals, licences, and permits, together with the conditions attaching to them. Such approvals may be delayed, withheld, suspended, or revoked, and conditions may be varied or tightened over time. Failure to obtain or maintain the necessary approvals or to comply with applicable laws could result in enforcement action, restrictions on activities, increased costs, or suspension or cessation of operations. Government policy settings and legislation are also subject to change, including in areas such as royalties and taxes, greenhouse gas emissions and climate policy, methane management, domestic gas reservation, indigenous peoples, and financial assurance for decommissioning. Any such changes could increase compliance costs, impose new operational constraints, reduce Projects returns, or adversely affect access to financing and insurance. There can be no assurance that the regulatory environment will not change in a way that materially and adversely impacts the Company's projects, financial position, prospects, or the value of its Shares. The Company's service contract areas may also be subject to overlapping third-party development rights, including solar energy development areas, which are permitted under Philippine energy law. While such overlaps are not currently expected to restrict the Company's petroleum exploration activities, there can be no assurance that third-party activities in or adjacent to the contract areas will not cause operational interference, access difficulties or regulatory complications that delay or increase the cost of the Company's exploration programmes.
Entry into joint venture or operator arrangements over the Projects	The Company will seek to progress the development and commercialisation of its Projects through joint venture arrangements or by entering into agreements with third-party operators. There is a risk that the Company may not be able to negotiate such arrangements on favourable terms, or at all. Even where agreements are entered into, the Company may have limited influence over the management and operation of the Projects, particularly where another party is then appointed as operator. Joint venture or operating counterparties may have commercial or strategic interests that differ from those of the Company. Disputes may arise in relation to budgets, work programs, development decisions, funding obligations or the allocation of costs and revenues. These disputes may result in delays, increased costs, or reduced Projects returns. There is also a risk that joint venture partners or operators may default on their obligations, experience financial distress, or withdraw from the Projects. Any of these outcomes could adversely affect the timing, cost, and ultimate viability of the Projects, which in turn may have a material negative impact on the Company's financial position and prospects.
Company's business strategy is speculative	While the Directors will, to the best of their knowledge, experience and abilities endeavour to anticipate, identify and manage the risks inherent in the activities of the Company, with the aim of eliminating, avoiding and mitigating the impact of risks on the performance of the Company and its business operations, the ability of the Directors and management to do so may be affected by matters outside their control given the nature of oil and gas exploration, development and production and no assurance can be given that the Directors and management of the Company will be successful in these endeavours.

RISK CATEGORY	RISK
Additional requirements for capital	The funds to be raised under the Public Offer (together with the existing cash reserves of the Company) are considered sufficient to meet the immediate objectives of the Company. The Company will require significant additional funding if it transitions to the development phase of its Projects and into production. In particular, the capital expenditure required to construct, commission, and operate production facilities, as well as associated infrastructure (other than existing infrastructure), is expected to exceed the funds available to the Company following completion of the Public Offer. Additional funding will also be required to support the Company's ongoing working capital requirements, to meet any cost overruns, and to pursue potential acquisitions or other business opportunities. There can be no assurance that such funding will be available when required, or on terms acceptable to the Company. Funding may be sought through equity or debt financing, joint venture, Projects operator or farm-in arrangements, or other forms of capital raising. Any equity financing may be dilutive to existing Shareholders, and debt financing (if available) may involve restrictive covenants or repayment obligations that could limit the Company's operational and financial flexibility. If the Company is unable to secure adequate funding, it may be required to delay, scale back, or suspend its development and production plans, which would materially impact its business, prospects, and financial position.
Exploration risk	Exploration activities may not result in the discovery of additional commercially feasible oil and gas resources. Exploration is subject to technical risks and uncertainty of outcome. The Company's ability to conduct exploration activities depends, among other things, on the availability of certain equipment, including drilling rigs. If the Company is unable to source appropriate equipment economically or at all, this may have a material adverse effect on the Company's exploration activities. The exploration costs of the Company are based on certain assumptions with respect to the method and timing of exploration. By their nature, estimates and assumptions are subject to significant uncertainties so the actual costs may differ significantly. This may adversely affect the Company's financial performance.
Infrastructure Access and Capacity Risk	Commercialisation of the hydrocarbons discovered on the Projects will likely depend on access to third-party infrastructure such as pipelines, gas processing facilities, LNG plants, storage, shipping and port services. Access to this infrastructure will require negotiation and maintenance of transportation, processing and offtake arrangements, and may be subject to regulatory approvals and capacity allocation processes. There is no assurance that suitable access can be obtained when required, on acceptable terms, or at all. Owners and operators may impose unfavourable tariffs, take-or-pay or nomination/balancing provisions, prioritise incumbent or integrated users, or require capital contributions for connections or capacity expansions. Infrastructure may also be unavailable due to capacity constraints, planned maintenance, unplanned outages, reliability issues, industrial action, extreme weather or force majeure events. Even where access is secured, curtailment, scheduling conflicts (including LNG train or shipping slot availability), changes to operating rules, or cost escalation can delay tie-ins and production, increase costs and reduce or defer revenues. Disputes with infrastructure owners or other users may also arise and cause interruption. Any inability to secure timely, reliable and cost-effective access to necessary infrastructure, or any material interruption to such access, could have a material adverse effect

RISK CATEGORY	RISK
	on the Company's operations, development schedule, financial position, prospects and the value of its Shares.
Operational risk and insurance	Oil and gas exploration and development activities include numerous operational risks, including but not limited to, adverse weather conditions, unforeseen increases in establishment costs, accidents (including, for example, fires, explosions, uncontrolled releases, spills and blowouts), industrial disputes, technical issues, supply chain failure or encountering unusual geological formations or other unforeseen events. Drilling operations, in particular, carry inherent risk associated with, for example, unexpected geological conditions, mechanical failures or human error. The occurrence of an operational risk may significantly increase operational costs and cause disruption to or hinder the advancement of the Company's exploration activities. The Company will mitigate this risk by, among other things, taking out appropriate insurance in line with industry practice, however insurance cover may be limited, unavailable (or unavailable on acceptable terms) or subject to exclusions. Significant events may not be fully covered.
Resource Recovery	Development plans for the Projects will be designed to optimise gas production from the Projects. Successful resource recovery is dependent on a number of factors including, but not limited to, confirmation of an economically recoverable resource, receiving the necessary approvals from all relevant authorities and parties, seasonal weather patterns, unanticipated technical and operational difficulties encountered in extraction and production activities, mechanical failure of operating plant and equipment, shortages or increases in the price of consumables, spare parts and plant and equipment, cost overruns, access to the required level of funding and contracting risk from third parties providing essential services. If the Company commences production on the Projects, its operations may be disrupted by a variety of risks and hazards which are beyond the control of the Company. No assurance can be given that the Company will achieve commercial viability through the development of the Projects. In addition, reservoir modelling undertaken on the Projects to date remains at an early stage and requires further maturation before a Final Investment Decision can be made. The Company's conceptual development plan also assumes that all development wells are optimally located based on current simulation model studies (where the reservoir is assumed to be 'known'). In practice, actual drilling outcomes are likely to vary, and contingency wells may be required to deliver the targeted resource recovery and production plateau. Should reservoir connectivity prove poorer than expected, or well performance deviate from modelled assumptions, additional wells may be required to achieve forecast production levels and maintain plateau duration. This could increase capital expenditure, extend development timelines, and negatively affect overall Projects economics. The risks associated with the development will be considered in full should the Projects reach that stage and will be managed with ongoing consideration of stakeholder interests.

7.3 Industry specific risks

RISK CATEGORY	RISK
Oil and gas price	The price at which the Company can sell any produced oil and gas will have a material influence on its financial performance and value of its Permits. It is impossible to predict future commodity prices with confidence and the factors which impact it include,

RISK CATEGORY	RISK
	but are not limited to, global political situations, military conflicts, technological changes, output controls and global energy consumption which are all outside the Company's control. A material and extended fall in realised oil and gas prices for the Company may, among other things, result in delays to transactions and work programs, adversely affect Projects economics or reduce recoverable reserves.
Currency price volatility	The Company's operations, future sales of oil and gas, and a significant portion of its development and production costs may be denominated in foreign currencies, including United States dollars. Movements in exchange rates between the Australian dollar and these foreign currencies could have a material impact on the Company's financial performance and position. For example, a depreciation of the Australian dollar against the United States dollar may increase the cost of imported equipment, services, and other expenditure, while an appreciation of the Australian dollar may reduce the Company's revenues (if commodity sales are denominated in United States dollars). The Company does not currently engage in any hedging arrangements to mitigate exchange rate exposure and there can be no assurance that such arrangements, if entered into in the future, will be available on commercially acceptable terms or will be successful in mitigating exposure to exchange rate fluctuations. Adverse currency movements may therefore have a material adverse effect on the Company's costs, revenues, profitability, and overall financial position.
Exploration costs	The exploration costs of the Company as summarised in Section 5 are based on certain assumptions with respect to the method and timing of exploration. By their nature, these estimates and assumptions are subject to significant uncertainty, and accordingly, the actual costs may materially differ from the estimates and assumptions. Accordingly, no assurance can be given that the cost estimates and the underlying assumptions will be realised in practice, which may materially and adversely impact the Company's viability.
Development Costs	The development costs of the Projects are based on certain assumptions with respect to the method and timing of the field development. By their nature, these estimates and assumptions are subject to significant uncertainty, and accordingly, the actual costs may materially differ from the estimates and assumptions. Accordingly, no assurance can be given that the cost estimates and the underlying assumptions will be realised in practice, which may materially and adversely impact the Projects's viability.
Reserves and Resources Estimates	Any reserves, contingent resources or prospective resources disclosed by the Company are estimates only. They are based on interpretations of geological, geophysical and petrophysical data, assumptions about reservoir characteristics and recovery factors, and economic inputs such as commodity prices, costs, fiscal terms and timing. Estimates are commonly prepared in accordance with the SPE Petroleum Resources Management System and rely on judgments by a Qualified Petroleum Reserves and Resources Evaluator. As additional data becomes available through drilling, testing, production or further seismic, or if assumptions change, the Company's reserves and resources may be revised (upwards or downwards), reclassified or removed. Conversion of resources to reserves depends on establishing commerciality, which in turn is sensitive to securing funding, approvals, introducing a qualified operator for the development of the Projects, confirming product specifications and offtake terms, and obtaining reliable access to processing and transport infrastructure. Changes in oil and gas prices, exchange rates, operating or capital costs, or government policy (including

RISK CATEGORY	RISK
	royalties, taxes and emissions requirements) may render currently estimated quantities uneconomic to develop. Any material downgrade or deferral of reserves or resources, or a failure to achieve forecast recovery factors or development timing, could adversely affect Projects economics, the Company's ability to progress development plans, reported asset values (including potential impairment) and the market price of the Shares.
Grant of future authorisations to explore and develop	If the Company discovers an economically viable resource deposit that it then intends to develop, it will, among other things, require various approvals, licence and permits before it will be able to begin production. There is no guarantee that the Company will be able to obtain all required approvals, licenses and permits. To the extent that required authorisations are not obtained or are delayed, the Company's operational and financial performance may be materially adversely affected.
Projects development	Possible future development of operations at the Projects is dependent on a number of factors including, but not limited to, the acquisition and/or delineation of economically recoverable resources, favourable geological conditions, receiving the necessary approvals from all relevant authorities and parties, seasonal weather patterns, unanticipated technical and operational difficulties encountered in extraction and production activities, mechanical failure of operating plant and equipment, shortages or increases in the price of consumables, spare parts and plant and equipment, cost overruns, access to the required level of funding and contracting risk from third parties providing essential services. If the Company commences production on one of the Projects, its operations may be disrupted by a variety of risks and hazards which are beyond the control of the Company. No assurance can be given that the Company will achieve commercial viability through the development of the Projects. The risks associated with the development of the Projects will be considered in full should the Projects reach that stage and will be managed with ongoing consideration of stakeholder interests.
Changes to fiscal terms and government policy in the Philippines	The Company's projects are located in the Philippines and are subject to the political, fiscal and regulatory environment of that jurisdiction. Adverse changes to laws, regulations, administrative practice, government policy, fiscal terms, foreign investment settings, exchange control arrangements, taxation, repatriation rules or permitting requirements may adversely affect the Company's ability to maintain its interests in the Projects, carry out work programmes, attract funding, commercialise any discovery or realise value from the Projects.
Counterparty, government and joint venture risk	The Projects may be subject to rights, obligations and approvals arising under permits, service contracts, farm-in arrangements, joint venture arrangements or other agreements involving government bodies and third parties. the Company may be adversely affected by counterparty default, non-performance, disputes, differing interpretations of contractual obligations, delay in obtaining required consents or approvals, or the inability to enforce rights on satisfactory terms. Any such event may delay work programmes, increase costs or adversely affect the Company's interest in the Projects.
Commercialisation and infrastructure risk	Even if the Company is successful in identifying hydrocarbons, there can be no assurance that those hydrocarbons can be developed or commercialised on acceptable terms. Commercialisation may depend on the availability and cost of processing, transport, export, offtake, market access, infrastructure tie-ins, development capital and access to third party facilities. Delays, constraints or adverse developments in any of these

RISK CATEGORY	RISK
	matters may adversely affect the timing, cost, feasibility or value of any future development of the Projects.
Supply chain and contractor availability risk	The Company's ability to undertake exploration, appraisal and development activities may depend on the timely availability of specialised contractors, drilling and seismic services, vessels, equipment, consumables and logistics support. Global or regional supply chain disruption, contractor underperformance, shortages of key inputs, mobilisation delays or cost inflation may adversely affect the timing, cost and execution of the Company's work programmes.
Environmental	The operations and proposed activities of the Company are subject to laws and regulations concerning the environment. Exploration and production activities involve environmental hazards, including spills of hydrocarbons or chemicals, well integrity failures, emissions and flaring, produced water management, noise and habitat disturbance (including marine impacts). the Company is subject to stringent environmental laws, regulations and approval conditions. Non-compliance or an incident may result in investigations, enforcement action, fines and penalties, clean-up and remediation costs, third-party claims, delays or shutdowns, reputational damage and, in serious cases, refusal, suspension or revocation of approvals. The Company will also incur ongoing obligations for rehabilitation and decommissioning, including plugging and abandonment of wells and removal of facilities, and the ultimate costs may be higher than currently anticipated.
Regulatory Compliance	The Company's operating activities are subject to extensive laws and regulations relating to numerous matters including resource licence consent, environmental compliance and rehabilitation, taxation, employee relations, health and worker safety, waste disposal, protection of the environment, heritage matters, protection of endangered and protected species and other matters. The Company requires permits from regulatory authorities to authorise the Company's operations. These permits relate to exploration, development, production and rehabilitation activities. While the Company believes that it is in substantial compliance with all material current laws and regulations, agreements or changes in their enforcement or regulatory interpretation could result in changes in legal requirements or in the terms of existing permits and agreements applicable to the Company or its properties, which could have a material adverse impact on the Company's current operations or planned development projects. Obtaining necessary permits can be a time-consuming process and there is a risk that Company will not obtain these permits on acceptable terms, in a timely manner or at all. The costs and delays associated with obtaining necessary permits and complying with these permits and applicable laws and regulations could materially delay or restrict the Company from proceeding with the development of a Projects or the operation or development of a mine. Any failure to comply with applicable laws and regulations or permits, even if inadvertent, could result in material fines, penalties or other liabilities. In extreme cases, failure could result in suspension of the Company's activities or forfeiture of one or more of the Permits.
Health and Safety	The Company's activities involve inherently hazardous operations, including drilling, well testing, pressure containment, hydrocarbons handling, marine and lifting operations, vehicle movements and work in remote environments. These activities present risks of personal injury or fatality, well-controlled incidents (including blowouts), loss of containment, fire, explosion and major process safety events. The Company must comply with applicable work health and safety (**WHS**) and petroleum safety regimes and

RISK CATEGORY	RISK
	approval conditions and is also exposed to the WHS performance of contractors and, where relevant, joint venture operators. A serious incident or systemic non-compliance may result in investigations, improvement or prohibition notices, directives to cease or modify work, prosecution, fines and penalties, increased regulatory oversight, Projects delays or shutdowns, and significant remediation and third-party costs. Insurance may not cover all consequences of such events. Safety outcomes depend on the effectiveness of management systems, competency and training, supervision, emergency response capability, and safety culture across the Company's workforce and supply chain. Factors such as contractor availability, labour turnover, equipment reliability, simultaneous operations and adverse weather can increase risk exposure. There is no assurance that controls will prevent all incidents or that incident impacts can be fully mitigated. Any material WHS event or well control incident could have a material adverse effect on the Company's people, operations, approvals, reputation, insurance availability and cost, financial position, prospects and the value of its Shares.

7.4 General risks

RISK CATEGORY	RISK
Market conditions	Share market conditions may affect the value of the Company's Shares regardless of the Company's operating performance. Share market conditions are affected by many factors such as: (a) general economic outlook; (b) introduction of tax reform or other new legislation; (c) interest rates and inflation rates; (d) changes in investor sentiment toward particular market sectors; (e) the demand for, and supply of, capital; and (f) terrorism or other hostilities. The market price of Shares can fall as well as rise and may be subject to varied and unpredictable influences on the market for equities in general and resource exploration stocks in particular.
Government policy changes	Adverse changes in government policies or legislation may affect ownership of oil and gas interests, taxation, royalties, land access, labour relations, and exploration and production activities of the Company. It is possible that the current system of exploration and production permitting in the Philippines may change, resulting in impairment of rights and possibly expropriation of the Company's properties without adequate compensation.
Insurance	The Company intends to insure its operations in accordance with industry practice. However, in certain circumstances the Company's insurance may not be of a nature or level to provide adequate insurance cover. The occurrence of an event that is not covered or fully covered by insurance could have a material adverse effect on the business, financial condition and results of the Company. Insurance of all risks associated with oil and gas exploration and production is not always available and where available the costs can be prohibitive.
Liquidity	There is no assurance that an active or liquid market for the Shares will develop or be sustained following Admission. Trading volumes in small to mid-capitalisation resource companies can be limited and uneven, which may exacerbate price volatility and make it difficult for Shareholders to acquire or dispose of Shares at

RISK CATEGORY	RISK
	prevailing market prices or within a desired timeframe. Low liquidity may also increase the bid-ask spread for the Shares, resulting in higher implicit transaction costs for investors. Market liquidity may be affected by a range of factors outside the Company's control, including overall market conditions, the number and profile of Shareholders, the presence (or absence) of broker research coverage, index inclusion, escrowed securities being released to market, and future capital raisings. Sales of Shares by substantial holders (or the perception that such sales may occur) could further reduce liquidity and place downward pressure on the Share price. Limited liquidity may therefore adversely affect the market value of the Shares irrespective of the Company's underlying performance.
Economic Conditions	The Company's operating costs, capital requirements and access to funding may be affected by broader macroeconomic conditions, including inflation, interest rates, exchange rates, labour market tightness and supply chain constraints. Cost inflation for key inputs (such as steel, fuel, drilling services and equipment) can increase Projects capital and operating expenditures, reduce margins and adversely affect Projects economics. Rising interest rates and tighter credit conditions may increase the cost of debt, reduce the availability of Projects finance, and lower investor risk appetite for equity raisings. Global and domestic economic slowdowns or recessions can depress energy demand, contribute to commodity price volatility and delay investment decisions by the Company and its counterparties (including infrastructure providers and offtakers). Adverse movements in exchange rates may affect the Australian dollar value of US dollar–denominated revenues or costs. These factors are outside the Company's control and may materially and adversely impact its operating performance, financial position, prospects and the market price of its Shares.
Reliance on Key Personnel	The responsibility of overseeing the day-to-day operations and the strategic management of the Company depends substantially on its Directors, senior management and its key personnel. There can be no assurance given that there will be no detrimental impact on the Company if one or more of these employees cease their employment. The Company's future depends, in part, on its ability to attract and retain key personnel. It may not be able to hire and retain such personnel at compensation levels consistent with its existing compensation and salary structure. Its future also depends on the continued contributions of its executive management team and other key management and technical personnel, the loss of whose services would be difficult to replace. In addition, the inability to continue to attract appropriately qualified personnel could have a material adverse effect on the Company's business.
Contractual Risk	The Company is a party to various agreements. The ability of the Company to achieve its stated objectives will depend on the performance by the parties of their respective obligations under the agreements. If the parties default in the performance of its obligations, the agreements may be terminated and it may be necessary for the Company to approach the Court to seek a legal remedy. Legal action can be costly and there can be no guarantee that a legal remedy will ultimately be granted on appropriate terms.
Competition Risk	The oil and gas industry in which the Company operates is subject to domestic and global competition. Although the Company will undertake all reasonable due diligence in its business decisions and operations, the Company will have no influence or control over the activities or actions of its competitors, which activities or

RISK CATEGORY	RISK
	actions may, positively or negatively, affect the operating and financial performance of the Company's Projects and business.
Force Majeure	The Company's Projects may be adversely affected by risks outside the control of the Company including labour unrest, civil disorder, war, subversive activities or sabotage, fires, floods, cyclones, explosions or other catastrophes, epidemics or quarantine restrictions.
Dilution	In the future, the Company may elect to issue Shares or engage in capital raisings to fund operations and growth, for investments or acquisitions that the Company may decide to undertake, to repay debt or for any other reason the Board may determine at the relevant time. While the Company will be subject to the constraints of the ASX Listing Rules regarding the percentage of its capital that it is able to issue within a 12-month period (other than where exceptions apply), Shareholder interests may be diluted as a result of such issues of Shares or other securities.
Taxation	The acquisition and disposal of Shares will have tax consequences, which will differ depending on the individual financial affairs of each investor. All potential investors in the Company are urged to obtain independent financial advice about the consequences of acquiring Shares from a taxation viewpoint and generally. To the maximum extent permitted by law, the Company, its officers and each of their respective advisers accept no liability and responsibility with respect to the taxation consequences of subscribing for Shares under this Prospectus.
Litigation Risks	The Company may be exposed to claims, disputes and regulatory investigations arising from its operations, including in relation to joint venture arrangements, farm-in/out agreements, native title, environmental compliance, occupational health and safety, personal injury, employment matters and contractual performance. Litigation and regulatory proceedings can be costly, time-consuming and unpredictable, may divert management attention and resources, and could result in fines, penalties, damages, injunctions, or orders that delay or restrict operations. Even where a claim lacks merit, defending it can entail significant expense and reputational risk. Adverse findings (including in relation to environmental incidents or WHS events) could also impact licences, approvals and stakeholder relationships. Any material dispute or proceeding could therefore have a significant adverse effect on the Company's financial position, cash flows, prospects and the market price of its Shares.
Global Events and Geopolitical	The Company's activities and financial performance may be affected by geopolitical events and broader global disruptions beyond its control. Conflicts, sanctions, trade restrictions, tariffs, terrorism, pandemics, natural disasters, cyber incidents, and disruptions to key shipping routes can adversely impact energy markets, commodity prices, logistics, insurance availability and costs, and the timing and cost of Projects inputs. Supply chain instability (including reduced availability of drilling rigs, well services, steel and specialist equipment) and transport bottlenecks may delay work programmes and increase capital and operating costs. Volatility in global financial markets can also affect access to equity and debt funding and increase the cost of capital. Prolonged or intensified geopolitical instability may reduce demand for hydrocarbons in some markets while increasing uncertainty and price volatility in others. Any of these factors could materially and adversely affect the Company's operations, schedule, costs, funding options, financial position, prospects and the value of its Shares.

7.5 Investment speculative

The risk factors described above, and other risks factors not specifically referred to, may have a materially adverse impact on the performance of the Company and the value of the Securities.

Prospective investors should consider that an investment in the Company is highly speculative.

The Securities offered under this Prospectus carry no guarantee in respect of profitability, dividends, return of capital or the price at which they may trade on the ASX.

Before deciding whether to subscribe for Securities under this Prospectus you should read this Prospectus in its entirety and consider all factors, taking into account your objectives, financial situation and needs.

8. BOARD AND KEY MANAGEMENT, CORPORATE GOVERNANCE AND ESG

8.1 Board of Directors

The Board of the Company consists of:

(a) **Greg Hancock – Non-Executive Chairman**

BA (Econs); BEd (Hons)

Mr Hancock is Non-executive Chairman of Triangle Energy (Global) Limited. Mr Hancock has over 25 years' experience in capital markets practising in the area of Corporate Finance. He has extensive experience in both Australia and the United Kingdom. In this time he has specialised in mining and natural resources and has a background in the finance and management of small listed companies. He was the founding shareholder and first Chairman of Cooper Energy Ltd (ASX: COE), an Australian oil and gas producer with operations in the Cooper, Otway and Gippsland basins. Mr Hancock is the non-executive chairman of ASX listed company Ausquest Ltd. He is also a non-executive director of WA Gold Limited.

The Board considers that Mr Hancock is an independent director.

(b) **Conrad Todd – Managing Director**

BSc Geology; MSc Stratigraphy

Mr Todd has over 40 years' experience in oil and gas exploration and development. He was Managing Director of Triangle from February 2022 and transitioned to Non-Executive Director following completion of the Spin-Out. Previously he has worked as Exploration and Development Manager for Cooper Energy and Lundin in Malaysia. In Indonesia he was Chief Geophysicist and New Business Manager for LASMO and in Oman was Chief Geophysicist for Occidental. During his time at Lundin in Malaysia he ran the subsurface team which produced 20,000 bopd from a complex mixed oil and gas field. Whilst at Cooper, he ran the geoscience department during a period of growth when the market cap went from $20 million to $200 million. He has also worked for RISC consulting in M&A and reserve auditing, and co-founded Vizier Energy Consulting.

He is a member of the American Association of Petroleum Geoscientists (AAPG), the Petroleum Exploration Society of Australia (PESA) and the Southeast Asia Petroleum Exploration Society (SEAPEX).

The Board considers that Mr Todd is not an independent director.

(c) **Mike Collins – Non-Executive Director**

BA (Hons) Geology; MSc Basin Evolution and Dynamics

Mr Collins is a Non-executive director of Triangle Energy (Global) Limited. Mr. Collins has almost 40 years' experience in Oil and Gas exploration and development in Perth and London. He worked as VP Exploration and Geoscience for Mitsui E&P Australia and as both Senior Geophysicist and Senior Business Analyst for Woodside Energy Ltd in Australia. He was Senior Explorationist for ENI in London. During his time at Mitsui E&P he managed the E&G subsurface team to provide focussed technical, economic and commercial advice/support across the Mitsui E&P exploration portfolio and assets in Australia, New Zealand, PNG and Indonesia culminating in various discoveries/acquisitions and divestments in the Browse, Exmouth, Otway, Gippsland, Taranaki and onshore Perth basins with significant asset acquisitions being Waitsia and Kipper.

He is a member of the Geological Society of London, the Petroleum Exploration Society of Australia (PESA), the Geoscience Energy Society of Great Britain (GESGB), the European Associations of Geoscientists and Engineers (EAGE) and the Southeast Asia Petroleum Exploration Society (SEAPEX).

The Board considers that Mr Collins is an independent director.

The Board has considered the Company's immediate requirements as it transitions to an ASX-listed company and is satisfied that the composition of the Board represents an appropriate range of experience, qualifications and skills at this time.

The Company is aware of the need to have sufficient management to properly supervise its operations and the Board will continually monitor the management roles in the Company. As the Company's work programs on the Projects and overall operations require an increased level of involvement the Board will look to appoint additional management and/or consultants when and where appropriate. The Company intends to utilise the services of experts and consultants for technical input, including to assist formulate overall business strategy and direction.

8.2 Key management

(a) **Marvin Chan – Proposed Chief Financial Officer**

Mr Chan has more than 19 years in financial leadership positions in the oil and gas and power generation industries within Southeast Asia and Australia. Mr Chan is a Fellow of the Certified Practising Accountants of Australia and a Certified Public Accountant and Lawyer in the Philippines.

Mr Chan will be appointed to the role of Chief Financial Officer effective from 1 July 2026. The terms of Mr Chan's engagement will be finalised prior to his appointment.

(b) **Sam Algar – Proposed Chief Operating Officer**

Dr Algar has more than 30 years' experience in the energy industry, having held senior leadership and executive roles in Australia and internationally, including the UK, Indonesia, Malaysia, Canada and the USA, looking after global exploration, new venture and subsurface portfolios. Most recently Dr Algar was Senior Vice President, Subsurface and Exploration with Oil Search Limited. Dr Algar holds a Bachelor of Arts (Hons) Geology from Oxford University and a PhD Geology from Dartmouth College in the USA. Previous employers include Ophir Energy, Murphy Oil, ENI, LASMO and Enterprise Oil.

Dr Algar will be appointed to the role of Chief Operating Officer effective from 1 July 2026. The terms of Dr Algar's engagement will be finalised prior to his appointment.

8.3 Directors' Disclosures

No Director has been the subject of (or was a director of a company that has been subject to) any legal or disciplinary action in Australia or elsewhere in the last ten years which is relevant or material to the performance of their role with the Company or which is relevant to an investor's decision as to whether to subscribe for Shares under the Public Offer.

No Director has been an officer of a company that has entered into any form of external administration as a result of insolvency during the time that they were an officer or within a 12-month period after they ceased to be an officer.

8.4 Directors' Remuneration and interests in Securities

Remuneration

Details of the Directors' remuneration (including superannuation) for the previous two completed and the current financial year (on an annualised basis) are set out in the table below:

DIRECTOR	REMUNERATION FOR THE FINANCIAL YEAR ENDED 30 JUNE 2024	REMUNERATION FOR THE FINANCIAL YEAR ENDED 30 JUNE 2025	PROPOSED REMUNERATION FOR FINANCIAL YEAR ENDING 30 JUNE 2026
Greg Hancock[1]	-	-	$54,000
Conrad Todd[1]	-	-	$325,000

Mike Collins[1]	-	-	$42,000

Notes:

1. Messrs Hancock, Todd and Collins were appointed to the Board on 6 February 2025 but have not received any remuneration as at the date of this Prospectus other than Mr Todd who commenced as Managing Director on 1 May 2026.

Interests in Securities

As at the date of this Prospectus

Directors are not required under the Company's Constitution to hold any Shares to be eligible to act as a director. As at the date of this Prospectus, the Directors have relevant interests in Securities as follows:

DIRECTOR	SHARES	OPTIONS	PERFORMANCE RIGHTS	% UNDILUTED
Greg Hancock	32,409[1]	Nil	Nil	0.16%
Conrad Todd	326,930[2]	Nil	Nil	1.66%
Mike Collins	126,550	Nil	Nil	0.64%

Notes:

1. Held indirectly by Hancock Corporate Investments Pty Ltd.
2. Comprising:
   (a) 126,793 Shares held directly by Mr Todd; and
   (b) 200,137 Shares held indirectly by Rosetti Super Holdings Pty Ltd <Rosetti Super Fund A/C>.

Post-completion of the Offers

The Directors' and proposed Directors' relevant interests in the Securities of the Company are set out in the table below:

DIRECTOR	SHARES	OPTIONS	PERFORMANCE RIGHTS	% UNDILUTED	% FULLY DILUTED
Greg Hancock[1]	82,409	Nil	900,000	0.33%	2.20%
Conrad Todd[2]	526,930	Nil	1,200,000	1.33%	3.69%
Mike Collins[3]	276,550	Nil	700,000	0.70%	2.08%

Notes:

1. Mr Hancock proposes to apply for 50,000 Shares under the Public Offer. Mr Hancock proposes to apply for 900,000 Performance Rights under the Management Offer.
2. Mr Todd proposes to apply for 200,000 Shares under the Public Offer. Mr Todd proposes to apply for 1,200,000 Performance Rights under the Management Offer.
3. Mr Collins proposes to apply for 150,000 Shares under the Public Offer. Mr Collins proposes to apply for 700,000 Performance Rights under the Management Offer.

The Constitution provides that the remuneration of non-executive Directors will be no more than the aggregate fixed sum determined by a general meeting. The aggregate remuneration for non-executive Directors is $500,000 per annum although may be varied by ordinary resolution of the Shareholders in general meeting.

The remuneration of any executive Director that may be appointed to the Board will be fixed by the Board and may be paid by way of fixed salary or consultancy fee.

In addition, the Directors (and their associates) may apply for Shares under the Public Offer. If one or more of the Directors (or their spouses or associates) do apply for, and are allocated, Shares under the Public Offer, the figures in the above table will be affected.

The Company will notify ASX of the Directors' interests in the Securities of the Company at the time of Admission in accordance with the ASX Listing Rules.

8.5 Agreements with Directors and related parties

The Company's policy in respect of related party arrangements is:

(a) a Director with a material personal interest in a matter is required to give notice to the other Directors before such a matter is considered by the Board; and

(b) for the Board to consider such a matter, the Director who has a material personal interest is not present while the matter is being considered at the meeting and does not vote on the matter.

The agreements between the Company and related parties are summarised at Sections 5.7 and 9.4.

8.6 Corporate governance

(a) **ASX Corporate Governance Council Principles and Recommendations**

The Company has adopted comprehensive systems of control and accountability as the basis for the administration of corporate governance.

The Board is committed to administering the policies and procedures with openness and integrity, pursuing the true spirit of corporate governance commensurate with the Company's needs.

To the extent applicable, the Company has adopted *The Corporate Governance Principles and Recommendations (4th Edition)* as published by ASX Corporate Governance Council (**Recommendations**).

In light of the Company's size and nature, the Board considers that the current board is a cost effective and practical method of directing and managing the Company. As the Company's activities develop in size, nature and scope, the size of the Board and the implementation of additional corporate governance policies and structures will be reviewed.

The Company's main corporate governance policies and practices as at the date of this Prospectus are outlined below and the Company's full Corporate Governance Plan is available in a dedicated corporate governance information section of the Company's website **www.tetragonenergy.com.au**.

(b) **Board of Directors**

The Board is responsible for corporate governance of the Company.

The Board develops strategies for the Company, reviews strategic objectives and monitors performance against those objectives. The goals of the corporate governance processes are to:

(i) maintain and increase Shareholder value;

(ii) ensure a prudential and ethical basis for the Company's conduct and activities consistent with the Company's stated values; and

(iii) ensure compliance with the Company's legal and regulatory objectives.

Consistent with these goals, the Board assumes the following responsibilities:

(i) leading and setting the strategic direction, values and objectives of the Company;

(ii) appointing the Chairman of the Board, Managing Director or Chief Executive Officer and approving the appointment of senior executives and the Company Secretary;

(iii) overseeing the implementation of the Company's strategic objectives, values, code of conduct and performance generally;

(iv) approving and monitoring the progress of major capital expenditure, capital management and significant acquisitions and divestitures;

(v) overseeing the integrity of the Company's accounting and corporate reporting systems, including any external audit (satisfying itself financial statements released to the market fairly and accurately reflect the Company's financial position and performance);

(vi) establishing procedures for verifying the integrity of those periodic reports which are not audited or reviewed by an external auditor, to ensure that each periodic report is materially accurate, balanced and provides investors with appropriate information to make informed investment decisions;

(vii) overseeing the Company's procedures and processes for making timely and balanced disclosure of all material information that a reasonable person would expect to have a material effect on the price or value of the Company's securities;

(viii) reviewing and ratifying systems of audit, risk management and internal compliance and control, codes of conduct and legal compliance to minimise the possibility of the Company operating beyond acceptable risk parameters; and

(ix) approving the Company's remuneration framework and ensuring it is aligned with the Company's purpose, values, strategic objectives and risk appetite.

The Company is committed to the circulation of relevant materials to Directors in a timely manner to facilitate Directors' participation in the Board discussions on a fully informed basis.

(c) **Composition of the Board**

Election of Board members is substantially the province of the Shareholders in general meeting, subject to the following:

(i) membership of the Board of Directors will be reviewed regularly to ensure the mix of skills and expertise is appropriate; and

(ii) the composition of the Board has been structured so as to provide the Company with an adequate mix of directors with industry knowledge, technical, commercial and financial skills together with integrity and judgment considered necessary to represent Shareholders and fulfil the business objectives and values of the Company as well as to deal with new and emerging business and governance issues.

The Board currently consists of three Directors of whom Messrs Hancock and Collins are considered independent. The Board considers the current balance of skills and expertise to be appropriate given the Company's size and its currently planned level of activity.

To assist in evaluating the appropriateness of the Board's mix of qualifications, experience and expertise, the Board intends to maintain a Board Skills Matrix to ensure that the Board has the skills to discharge its obligations effectively and to add value.

The Board undertakes appropriate checks before appointing a person as a Director or putting forward to Shareholders a candidate for election as a Director or senior executive.

The Board ensures that Shareholders are provided with all material information in the Board's possession relevant to a decision on whether or not to elect or re-elect a Director.

The Company shall develop and implement a formal induction program for Directors, which is tailored to their existing skills, knowledge and experience.

The purpose of this program is to allow new directors to participate fully and actively in Board decision-making at the earliest opportunity, and to enable new directors to gain an understanding of the Company's policies and procedures.

The Board maintains oversight and responsibility for the Company's continual monitoring of its diversity practices.

The Company's Diversity Policy provides a framework for the Company to achieve enhanced recruitment practices whereby the best person for the job is employed, which requires the consideration of a broad and diverse pool of talent.

(d) **Identification and management of risk**

The Board's collective experience will enable accurate identification of the principal risks that may affect the Company's business.

Key operational risks and their management will be recurring items for deliberation at Board meetings.

(e) **Ethical standards**

The Board is committed to the establishment and maintenance of appropriate ethical standards and to conducting all of the Company's business activities fairly, honestly with integrity, and in compliance with all applicable laws, rules and regulations.

In particular, the Company and the Board are committed to preventing any form of bribery or corruption and to upholding all laws relevant to these issues as set out in the Company's Anti-Bribery and Anti-Corruption Policy.

In addition, the Company encourages reporting of actual and suspected violations of the Company's Code of Conduct or other instances of illegal, unethical or improper conduct.

The Company and the Board provide effective protection from victimisation or dismissal to those reporting such conduct as set out in its Whistleblower Protection Policy.

(f) **Independent professional advice**

Subject to the Chairman's approval (not to be unreasonably withheld), the Directors, at the Company's expense, may obtain independent professional advice on issues arising in the course of their duties.

(g) **Remuneration arrangements**

The remuneration of an executive Director will be decided by the Board, without the affected executive Director participating in that decision-making process.

In accordance with the Constitution, the total maximum remuneration of non-executive Directors is initially set by the Board and subsequent variation is by ordinary resolution of Shareholders in general meeting in accordance with the Constitution, the Corporations Act and the ASX Listing Rules, as applicable.

The determination of non-executive Directors' remuneration within that maximum will be made by the Board having regard to the inputs and value to the Company of the respective contributions by each non-executive Director. The current amount has been set at an amount not to exceed $500,000 per annum.

In addition, a Director may be paid fees or other amounts for example, and subject to any necessary Shareholder approval, non-cash performance incentives such as options) as the Directors determine where a Director performs special duties or otherwise performs services outside the scope of the ordinary duties of a Director.

Directors are also entitled to be paid reasonable travelling, hotel and other expenses incurred by them respectively in the performance of their duties as Directors.

The Board reviews and approves the remuneration policy to enable the Company to attract and retain executives and Directors who will create value

for Shareholders having regard to the amount considered to be commensurate for a company of its size and level of activity as well as the relevant Directors' time, commitment and responsibility.

The Board is also responsible for reviewing any employee incentive and equity-based plans including the appropriateness of performance hurdles and total payments proposed.

(h) **Trading policy**

The Board has adopted a policy that sets out the guidelines on the sale and purchase of securities in the Company by its key management personnel (i.e., Directors and, if applicable, any employees reporting directly to the managing director).

The policy generally provides that, the written acknowledgement of the Chair (or the Board in the case of the Chairman) must be obtained prior to trading.

(i) **External audit**

The Company in general meetings is responsible for the appointment of the external auditors of the Company. From time to time, the Board will review the scope, performance and fees of those external auditors.

(j) **Audit committee**

The Company will not have a separate audit committee until such time as the Board is of a sufficient size and structure, and the Company's operations are of a sufficient magnitude for a separate committee to be of benefit to the Company. In the meantime, the full Board will carry out the duties that would ordinarily be assigned to that committee under the written terms of reference for that committee, including but not limited to:

(i) monitoring and reviewing any matters of significance affecting financial reporting and compliance;

(ii) verifying the integrity of those periodic reports which are not audited or reviewed by an external auditor;

(iii) monitoring and reviewing the Company's internal audit and financial control system, risk management systems; and

(iv) management of the Company's relationships with external auditors.

(k) **Diversity policy**

The Company is committed to workplace diversity.

The Company is committed to inclusion at all levels of the organisation, regardless of gender, marital or family status, sexual orientation, gender identity, age, disabilities, ethnicity, religious beliefs, cultural background, socio-economic background, perspective and experience.

The Board has adopted a diversity policy which provides a framework for the Company to achieve, amongst other things, a diverse and skilled workforce, a workplace culture characterised by inclusive practices and behaviours for the benefit of all staff, improved employment and career development opportunities for women and a work environment that values and utilises the contributions of employees with diverse backgrounds, experiences and perspectives.

(l) **Departures from Recommendations**

Under the ASX Listing Rules the Company will be required to provide a statement in its annual financial report or on its website disclosing the extent to which it has followed the Recommendations during each reporting period.

Where the Company has not followed a Recommendation, it must identify the Recommendation that has not been followed and give reasons for not following it.

The Company's compliance with and departures from the Recommendations will also be announced prior to Admission.

8.7 Environmental, Social and Governance

The Company is aware of its obligations under relevant law in respect of Environmental, Social and Governance (**ESG**) principles and is committed to embedding those principles into its long-term strategy. The Company has adopted an ESG Policy and is committed to manage its activities to the extent appropriate.

In the course of its business, the Company is committed to monitoring ESG risks and focus on:

(a) **Environment** – ensuring that, as a minimum, all policies and procedures comply with applicable environmental laws and regulations in jurisdictions in which the Company conducts activities, and identifying, managing and reporting on material environmental risks and impacts including greenhouse gas emissions, water management and waste reduction.

(b) **Climate Change** – identifying and managing climate change risks and opportunities, increasing transparency of climate change reporting, and assessing options to improve energy efficiency and increase use of lower-emission energy technologies;

(c) **Social** – providing and maintaining a safe workplace for employees, contractors and visitors, building strong relationships with host communities, respecting human rights, and recognising the cultural heritage and traditions of indigenous peoples in areas where the Company operates.

(d) **Governance** – conducting all business activities fairly, honestly and with integrity, maintaining high standards of corporate governance and regulatory compliance, and promoting ethical and responsible decision-making to earn the trust of the Company's stakeholders.

The Company's full ESG Policy is available on the Company's website at **www.tetragonenergy.com.au**.

9. MATERIAL CONTRACTS

The Directors consider that the material contracts described below are those which an investor would reasonably regard as material and which investors, and their professional advisers would reasonably expect to find described in this Prospectus for the purpose of making an informed assessment of an investment in the Company under the Public Offer.

This Section contains a summary of the material contracts and their substantive terms which are not otherwise disclosed elsewhere in this Prospectus.

To fully understand all rights and obligations of a material contract, it is necessary to review it in full, and these summaries should be read in this light.

9.1 Lead Manager Mandate

The Company has signed a mandate letter to engage Powerhouse to act as the Lead Manager of the Public Offer (**Lead Manager Mandate**). The material terms and conditions of which are summarised below:

Services	To act as the exclusive Lead Manager to the Company's Public Offer.
Fees	As consideration for services provided in connection with the Public Offer, the Company will pay the Lead Manager the following fees: (a) a capital raising and management fee of 6% (exclusive of GST) on capital raised from all sources under the Public Offer; and (b) 2,000,000 Options to the Lead Manager or its nominees exercisable at $0.30 per Option on or before the date that is 4 years from the date of issue.
Term and Termination	The Lead Manager Mandate continues for a term of 12 months (from 21 January 2026) unless validly terminated in accordance with its terms. Either party may terminate the Lead Manager Mandate by giving the other party 60 days' written notice, or immediately by written notice if the other party is in breach of the Lead Manager Mandate.
Exclusivity	Notwithstanding the expiry or termination of the Lead Manager Mandate, the Company further agrees that should it cancel and/or re-initiate an IPO transaction, it will not, either directly or indirectly, contact or engage with a third party that is introduced by the Lead Manager as a result of the engagement under the Lead Manager Mandate (an **Introduced Party**), as introduced by the Lead Manager. In the event that the Company or a related entity enters an agreement or accepts any offer from an Introduced Party, the Company agrees to pay the Lead Manager, a fee calculated in accordance with the fees payable above in relation to sums invested or paid by that Introduced Party.
Withdrawal fee	If the Company terminates the Lead Manager Mandate for any reason other than pursuant to the negligence, recklessness, breach, wilful misconduct or fraud of the Lead Manager and the termination occurs during the term of the Lead Manager Mandate, the Company undertakes any alternative form of equity or hybrid capital raising other than the Public Offer (Alternative Offer) or enters into an agreement with a third party pursuant to which the third party agrees to acquire 50.0% or more of the Company (whether by way of share, business or asset purchase), (each a Withdrawal Fee Event), the Company will pay the Lead Manager a withdrawal fee calculated as follows: (a) if the Withdrawal Fee Event occurs after the first meeting of the due diligence committee but prior to the commencement of the investor roadshow, a fee of $10,000 for each month (or part thereof) since the first due diligence committee meeting, up to a maximum of $50,000;

	(b) if the Withdrawal Fee Event occurs after the commencement of the investor roadshow but prior to lodgement by this Prospectus with ASIC, a fee of $75,000; or (c) if the Withdrawal Fee Event occurs after lodgement of this Prospectus with ASIC, a fee equal to half of the amount of the Public Offer that would have been payable to the Lead Manager by the Company had the Public Offer completed
Future retainer	On the Company's admission to the ASX, the Lead Manager will be automatically retained for a period of eighteen (18) months from the date of the Company's listing.
First right for future raisings	The Company agrees to offer the Lead Manager a first right of refusal to be appointed as lead manager in any future equity capital financing on agreed and competitive arms-length market terms and conditions within twelve months following completion of the Public Offer.

The Lead Manager Mandate otherwise contains provisions considered standard for an agreement of its nature (including representations and warranties, indemnities and confidentiality provisions).

9.2 Corporate Advisory Mandate

The Company has signed a mandate letter to engage Salient Corporate to corporate advisory of the Company in respect of the Public Offer (**Corporate Advisory Mandate**). The material terms and conditions of which are summarised below:

Services	Corporate advisory services in relation to the progress of the Company.
Fees	In consideration for services by Salient Corporate, the Company will pay Salient Corporate the following fees (a) a monthly retainer of $5,000 per month. The quantum of the monthly advisory fee may be reviewed by the Company after 6 months; and (b) 1,250,000 Options to Salient Corporate or its nominees exercisable at $0.30 per Option on or before the date that is 3 years from the date of issue.
Capital raising fees	The Lead Manager shall pay Salient Corporate a fee of 1% of the amount raised under the Public Offer from sources other than the Lead Manager or Salient Corporate and 6% of the amount subscribed directly by Salient Corporate or its network pursuant to the Public Offer.
M&A Success Fee	In the event the Company undertakes a material M&A transaction with the assistance of Salient Corporate, the Company will pay Salient a success based on the gross value of the transaction the amount of which shall be determined having regard for the standard market rates for M&A transaction fees (2.0% - 3.0%) and the level of involvement and level of prior work that Salient Corporate has provided pursuant to a separate letter of engagement at the time of any transaction.
Term and Termination	The Corporate Advisory Mandate continues for a term of 18 months (from 20 April 2026) unless validly terminated in accordance with its terms. Either party may terminate the Lead Manager Mandate by giving the other party 3 months' written notice.

The Corporate Advisory Mandate otherwise contains provisions considered standard for an agreement of its nature (including representations and warranties, indemnities and confidentiality provisions).

9.3 Joint Operating Agreement

The Company, through its wholly-owned subsidiary Tetragon Philippines is proposing to enter into joint operating agreements (**JOAs**) with Sunda Energy Plc, PXP Energy Corporation and Philodrill Corporation to govern the joint exploration and development of each of SC-80 and SC-81.

The current proposed terms of each JOA are summarised in the table below:

Parties and Participating Interests	(a) Tetragon Philippines: 37.5% (Operator); (b) Sunda Energy Plc: 37.5%; (c) PXP Energy Corporation: 12.5%; and (d) Philodrill Corporation:12.5%.
Operatorship	Tetragon Philippines serves as Operator of SC-80 and SC-81 and is responsible for conducting and managing all joint operations on behalf of the joint venture parties. The Operator acts as agent for the non-operating parties and has broad discretion in the day-to-day conduct of operations, subject to approved work programs and budgets and operating committee oversight.
Operating committee	An operating committee comprising one representative from each participant governs decision-making for the joint venture. An operating committee comprising one representative from each participant governs decision-making for the joint venture. Decisions require varying levels of approval depending on the nature of the matter, with routine operational decisions requiring a simple majority of voting interests and more significant decisions (including approval of work programs and budgets and the conduct of exclusive operations) requiring higher thresholds.
Work Programs, Budgets and Cash Calls	The JOA will contains provision governing the preparation and approval of work programs and budgets, cash call mechanisms and the consequences of failing to meet cash call obligations.
Operations, Production and Decommissioning	The JOA will contains provision governing the conduct of operations, disposition of production, data sharing, insurance, and decommissioning and abandonment obligations.
Removal of Operator	The Operator may be removed in the following circumstances: (a) automatically upon insolvency, bankruptcy, appointment of a receiver, or winding up of the Operator; (b) for cause by affirmative vote of two or more non-operator participants holding at least 60% of the non-operator interests, where the Operator has committed a material breach that is not remedied within 30 days of notice; (c) if there is a change in control of the Operator (other than to an affiliate), the parties must vote within 30 days on whether to remove the Operator, and removal requires an affirmative vote of two or more parties holding at least 65% of all participating interests; and (d) if the Operator's participating interest falls below 20% as a result of a transfer, the parties must vote within 30 days on whether to remove the Operator, and removal requires an affirmative vote of two or more parties holding at least 65% of all participating interests.
Transfer and Withdrawal	(a) Transfers of participating interests require the consent of all other parties provided that no transfer may result in the transferor or transferee holding less than 5% participating interest. (b) Any non-defaulting party may withdraw from the JOA on written notice, in which case it must assign its interest to the remaining parties at no cost but remains liable for obligations attributable to it prior to withdrawal, including decommissioning costs.

Default	A participant is in default if it fails to pay its share of joint account charges (including cash calls) when due. Upon default, the defaulting party: (a) loses its right to receive its share of production for the duration of the default period, which vests in the non-defaulting parties; (b) is excluded from attending and voting at operating committee meetings; and (c) is deemed to approve all actions voted on during the default period. If the default is not remedied within 30 days, non-defaulting parties may exercise one or more of the following remedies: (a) require a forced transfer of the defaulting party's entire participating interest; (b) compel a buy-out of the defaulting party's interest at a price equal to fair market value less a 25% discount and the total amount in default; or (c) foreclose on the defaulting party's interest pursuant to a security interest granted under the JOA.

The JOA otherwise will contain provisions considered standard for an agreement of its nature, including representations and warranties, confidentiality obligations, force majeure and anti-bribery and anti-corruption compliance requirements.

9.4 Agreements with Directors and management

9.4.1 Conrad Todd – Executive Services Agreement (Managing Director)

On 15 April 2026, the Company entered into an executive services agreement with Conrad Todd (**ESA**), pursuant to which Conrad Todd has been appointed as Managing Director of the Company, the material terms and conditions of which are summarised below:

Position	Managing Director
Remuneration	$325,000 per annum (**Salary**)
Term	The engagement will continue until the ESA is validly terminated in accordance with its terms.
Termination by Mr Todd	Mr Todd may terminate the ESA by providing the Company with 6 months written notice. The Company may dispense of part or all of the notice period by making payment in lieu of the Salary for the equivalent period.
Termination by Company	The Company may terminate the ESA by providing Mr Todd with 6 months written notice. The Company may dispense of part or all of the notice period by making payment in lieu of the Salary for the equivalent period. The Company may terminate Mr Todd's employment summarily for cause without notice or payment in lieu of notice.

The ESA otherwise contains provisions considered standard for an agreement of its nature (including representations and warranties and confidentiality provisions).

9.4.2 Non-executive Director appointments

Greg Hancock has entered into an appointment letter with the Company to act in the capacity of non-executive Chairman. Mr Hancock will receive the remuneration and interests set out in Section 8.4. The appointment letter otherwise contains provisions considered standard for an agreement of its nature.

Mike Collins has entered into an appointment letter with the Company to act in the capacity of non-executive director. Mr Collins will receive the remuneration and interests set out in Section 8.4. The appointment letter otherwise contains provisions considered standard for an agreement of its nature.

9.4.3 Deeds of indemnity, insurance and access

The Company will enter into a deed of indemnity, insurance and access with each of its officers. Pursuant to each of these deeds, the Company has agreed to indemnify each officer, to the extent permitted by the Corporations Act against certain liabilities arising as a result of the officer acting as an officer of the Company. The Company will also be required to maintain insurance policies for the benefit of the relevant officer and allow the officers to inspect board papers in certain circumstances.

10. ADDITIONAL INFORMATION

10.1 Litigation

As at the date of this Prospectus, the Company is not involved in any legal proceedings, and the Directors are not aware of any legal proceedings pending or threatened against the Company.

10.2 Rights and liabilities attaching to Shares

The following is a summary of the more significant rights and liabilities attaching to the Shares being offered pursuant to this Prospectus. This summary is not exhaustive and does not constitute a definitive statement of the rights and liabilities of Shareholders. To obtain such a statement, persons should seek independent legal advice.

Full details of the rights and liabilities attaching to Shares are set out in the Constitution, a copy of which is available for inspection at the Company's registered office during normal business hours.

(a) **General meetings**

Shareholders are entitled to be present in person, or by proxy, attorney or representative to attend and vote at general meetings of the Company. The Company's constitution permits the use of technology at general meetings of shareholders (including wholly virtual meetings) to the extent permitted under the Corporations Act, Listing Rules and applicable law.

Shareholders may requisition meetings in accordance with section 249D of the Corporations Act and the Constitution of the Company.

(b) **Voting rights**

Subject to any rights or restrictions for the time being attached to any class or classes of shares, at general meetings of shareholders or classes of shareholders:

(i) each Shareholder entitled to vote may vote in person or by proxy, attorney or representative;

(ii) on a show of hands, every person present who is a Shareholder or a proxy, attorney or representative of a Shareholder has one vote; and

(iii) on a poll, every person present who is a Shareholder or a proxy, attorney or representative of a Shareholder shall, in respect of each fully paid Share held by him, or in respect of which he is appointed a proxy, attorney or representative, have one vote for each Share held, but in respect of partly paid shares shall have such number of votes as bears the same proportion to the total of such Shares registered in the Shareholder's name as the amount paid (not credited) bears to the total amounts paid and payable (excluding amounts credited).

(c) **Dividend rights**

Subject to the rights of any preference Shareholders and to the rights of the holders of any shares created or raised under any special arrangement as to dividend, the Directors may from time to time declare a dividend to be paid to the Shareholders entitled to the dividend which shall be payable on all Shares according to the proportion that the amount paid (not credited) is of the total amounts paid and payable (excluding amounts credited) in respect of such Shares.

The Directors may from time to time pay to the Shareholders any interim dividends as they may determine. No dividend shall carry interest as against the Company. The Directors may set aside out of the profits of the Company any amounts that they may determine as reserves, to be applied at the discretion of the Directors, for any purpose for which the profits of the Company may be properly applied.

Subject to the ASX Listing Rules and the Corporations Act, the Company may, by resolution of the Directors, implement a dividend reinvestment plan on such terms and conditions as the Directors think fit and which provides for any dividend which the Directors may declare from time to time payable on Shares which are participating Shares in the dividend reinvestment plan, less any amount which the Company shall either pursuant to the Constitution or any law be entitled or obliged to retain, be applied by the Company to the payment of the subscription price of Shares.

(d) **Winding-up**

If the Company is wound up, the liquidator may, with the authority of a special resolution, divide among the Shareholders in kind the whole or any part of the property of the Company, and may for that purpose set such value as he considers fair upon any property to be so divided, and may determine how the division is to be carried out as between the Shareholders or different classes of Shareholders.

The liquidator may, with the authority of a special resolution, vest the whole or any part of any such property in trustees upon such trusts for the benefit of the contributories as the liquidator thinks fit, but so that no Shareholder is compelled to accept any shares or other securities in respect of which there is any liability.

(e) **Shareholder liability**

As the Shares issued will be fully paid shares, they will not be subject to any calls for money by the Directors and will therefore not become liable for forfeiture.

(f) **Transfer of shares**

Generally, shares in the Company are freely transferable, subject to formal requirements, the registration of the transfer not resulting in a contravention of or failure to observe the provisions of a law of Australia and the transfer not being in breach of the Corporations Act and the ASX Listing Rules.

(g) **Future increase in capital**

The issue of any new Shares is under the control of the Directors of the Company. Subject to restrictions on the issue or grant of securities contained in the ASX Listing Rules, the Constitution and the Corporations Act (and without affecting any special right previously conferred on the holder of an existing share or class of shares), the Directors may issue Shares, as they shall, in their absolute discretion, determine.

(h) **Variation of rights**

Under section 246B of the Corporations Act, the Company may, with the sanction of a special resolution passed at a meeting of Shareholders vary or abrogate the rights attaching to Shares.

If at any time the share capital is divided into different classes of shares, the rights attached to any class (unless otherwise provided by the terms of issue of the shares of that class), whether or not the Company is being wound up, may be varied or abrogated with the consent in writing of the holders of three quarters of the issued shares of that class, or if authorised by a special resolution passed at a separate meeting of the holders of the shares of that class.

(i) **Alteration of constitution**

In accordance with the Corporations Act, the Constitution can only be amended by a special resolution passed by at least three quarters of Shareholders present and voting at the general meeting. In addition, at least 28 days written notice specifying the intention to propose the resolution as a special resolution must be given.

10.3 Terms and conditions of the Options under the Lead Manager Offer and Advisor Offer

Set out below are the terms and conditions of the Options under the Lead Manager Offer and Advisor Offer:

(a) **Entitlement**

Each Option entitles the holder to subscribe for one Share upon exercise of the Option.

(b) **Exercise Price**

Subject to Paragraph (i), the amount payable upon exercise of each Option will be $0.30 (**Exercise Price**).

(c) **Expiry Date**

(i) Each Option issued under the Lead Manager Offer will expire at 5:00 pm (WST) on the date that is four years from the date of issue; and

(ii) each Option issued under the Advisor Offer will expire at 5:00 pm (WST) on the date that is three years from the date of issue,

(each an **Expiry Date**). An Option not exercised before the Expiry Date will automatically lapse on the Expiry Date.

(d) **Exercise Period**

The Options are exercisable at any time on or prior to the Expiry Date (**Exercise Period**).

(e) **Exercise Notice**

The Options may be exercised during the Exercise Period by notice in writing to the Company in the manner specified on the Option certificate (**Exercise Notice**) and payment of the Exercise Price for each Option being exercised in Australian currency by electronic funds transfer or other means of payment acceptable to the Company.

(f) **Exercise Date**

An Exercise Notice is only effective on and from the later of the date of receipt of the Exercise Notice and the date of receipt of the payment of the Exercise Price for each Option being exercised in cleared funds (**Exercise Date**).

(g) **Timing of issue of Shares on exercise**

Within five Business Days after the Exercise Date, the Company will:

(i) issue the number of Shares required under these terms and conditions in respect of the number of Options specified in the Exercise Notice and for which cleared funds have been received by the Company;

(ii) if required, give ASX a notice that complies with section 708A(5)(e) of the Corporations Act, or, if the Company is unable to issue such a notice, lodge with ASIC a prospectus prepared in accordance with the Corporations Act and do all such things necessary to satisfy section 708A(11) of the Corporations Act to ensure that an offer for sale of the Shares does not require disclosure to investors; and

(iii) if admitted to the official list of ASX at the time, apply for official quotation on ASX of Shares issued pursuant to the exercise of the Options.

If a notice delivered under paragraph (h)(ii) for any reason is not effective to ensure that an offer for sale of the Shares does not require disclosure to investors, the Company must, no later than 20 business days after becoming aware of such notice being ineffective, lodge with ASIC a prospectus prepared in accordance with the Corporations Act and do all such things necessary to satisfy

section 708A(11) of the Corporations Act to ensure that an offer for sale of the Shares does not require disclosure to investors.

(h) **Shares issued on exercise**

Shares issued on exercise of the Options rank equally with the then issued shares of the Company.

(i) **Reorganisation**

If there is a reorganisation of the issued share capital of the Company (including any subdivision, consolidation, reduction, return or cancellation of such issued capital of the Company), the rights of the holder will be changed to the extent necessary to comply with the ASX Listing Rules applicable to a reorganisation of capital at the time of the reorganisation.

(j) **Participation in new issues**

There are no participation rights or entitlements inherent in the Options and holders will not be entitled to participate in new issues of capital offered to Shareholders during the currency of the Options without exercising the Options.

(k) **Change in exercise price**

An Option does not confer the right to a change in Exercise Price or a change in the number of underlying securities over which the Option can be exercised.

(l) **Transferability**

The Options are transferable subject to any restriction or escrow arrangements imposed by ASX or under applicable Australian securities laws.

10.4 Terms and conditions of the Performance Rights under the Management Offer

Set out below are the terms and conditions of the Performance Rights proposed to be issued under the Management Offer:

(a) **Vesting Conditions and Expiry Dates**

The Performance Rights shall vest on each of the following **Vesting Conditions** and each Performance Right shall otherwise expire on the following **Expiry Dates**:

CLASS	NUMBER	VESTING CONDITION	EXPIRY DATE
A	1,560,000	The Company's net resources by 25%, as independently certified by a Competent Person in accordance with the Petroleum Resources Management System (PRMS), on or before 31 December 2026.	31 August 2027
B	1,170,000	Either of the following conditions being satisfied on or before 31 December 2026: the Company entering into a binding agreement to acquire a new project or asset, or the Company entering into a binding farm-out agreement in respect of an existing project or tenement, in each case on terms satisfactory to the Board; or the Company's volume weighted average share price calculated over any 15 consecutive ASX trading days on which the Company's shares are traded equalling or exceeding $0.40	31 August 2027
C	1,170,000	No material environmental incidents and no Lost Time Injuries (LTIs) having been recorded in connection with the Company's operations during the period	31 August 2027

CLASS	NUMBER	VESTING CONDITION	EXPIRY DATE
		from the date of issue to 31 December 2026.	

(b) **Notification to holder**

The Company shall notify the holder in writing when the relevant Vesting Condition has been satisfied.

(c) **Conversion**

Subject to paragraph (o), upon vesting, each Performance Right will, at the election of the holder, convert into one Share.

(d) **Expiry of Performance Rights**

If the relevant Vesting Condition attached to the Performance Right has not been achieved by the Expiry Date, all unconverted Performance Rights of the relevant tranche will automatically lapse at that time. For the avoidance of doubt, the Performance Rights only lapse in this circumstance and do not lapse if the holder ceases to be employed or engaged by the Company.

(e) **Consideration**

The Performance Rights will be issued for nil consideration, and no consideration will be payable upon the conversion of the Performance Rights into Shares.

(f) **Share ranking**

All Shares issued upon the vesting of Performance Rights will upon issue rank pari passu in all respects with other existing Shares.

(g) **Application to ASX**

The Performance Rights will not be quoted on ASX. The Company must apply for the official quotation of a Share issued on conversion of a Performance Right on ASX within the time period required by the ASX Listing Rules.

(h) **Timing of issue of Shares on conversion**

Within 5 business days after the date that the Performance Rights are converted, the Company will:

(i) issue the number of Shares required under these terms and conditions in respect of the number of Performance Rights converted;

(ii) if required, give ASX a notice that complies with section 708A(5)(e) of the Corporations Act, or, if the Company is unable to issue such a notice, lodge with ASIC a prospectus prepared in accordance with the Corporations Act and do all such things necessary to satisfy section 708A(11) of the Corporations Act to ensure that an offer for sale of the Shares does not require disclosure to investors; and

(iii) if admitted to the Official List of ASX at the time, apply for official quotation on ASX of Shares issued pursuant to the conversion of the Performance Rights.

If a notice delivered under paragraph (h)(ii) for any reason is not effective to ensure that an offer for sale of the Shares does not require disclosure to investors, the Company must, no later than 20 business days after becoming aware of such notice being ineffective, lodge with ASIC a prospectus prepared in accordance with the Corporations Act and do all such things necessary to satisfy section 708A(11) of the Corporations Act to ensure that an offer for sale of the Shares does not require disclosure to investors.

(i) **Transfer of Performance Rights**

The Performance Rights are not transferable.

(j) **Participation in new issues**

A Performance Right does not entitle a holder (in their capacity as a holder of a Performance Right) to participate in new issues of capital offered to holders of Shares such as bonus issues and entitlement issues without exercising the Performance Right.

(k) **Reorganisation of capital**

If at any time the issued capital of the Company is reorganised (including consolidation, subdivision, reduction or return), all rights of a holder will be changed in a manner consistent with the applicable ASX Listing Rules and the Corporations Act at the time of reorganisation.

(l) **Adjustment for bonus issues of Shares**

If the Company makes a bonus issue of Shares or other securities to the Company's existing shareholders (other than an issue in lieu or in satisfaction of dividends or by way of dividend reinvestment) the number of Shares or other securities which must be issued on the conversion of a Performance Right will be increased by the number of Shares or other securities which the holder would have received if the holder had converted the Performance Right before the record date for the bonus issue.

(m) **Dividend and voting rights**

The Performance Rights do not confer on the holder an entitlement to vote (except as otherwise required by law) or receive dividends.

(n) **Change in control**

Subject to paragraph (o), upon:

(i) a bona fide takeover bid under Chapter 6 of the Corporations Act having been made in respect of the Company and:

(A) having received acceptances for not less than 50.1% of the Company's Shares on issue; and

(B) having been declared unconditional by the bidder;

(ii) any person acquires a Relevant Interest in at least 50.1% or more of the issued Shares by any other means;

(iii) the Company sells, transfers or otherwise disposes of all or substantially all of the Projects (in one transaction or a series of related transaction);

(iv) a Court granting orders approving a compromise or arrangement for the purposes of or in connection with a scheme for the reconstruction of the Company or its amalgamation with any other company or companies; or

(v) in any other case, a person obtains Voting Power (as defined in the Corporations Act) in the Company that the Board (which for the avoidance of doubt will comprise those Directors immediately prior to the person acquiring that Voting Power) determines, acting in good faith and in accordance with their fiduciary duties, is sufficient to control the composition of the Board,

then, to the extent Performance Rights have not converted into Shares due to satisfaction of the relevant Vesting Conditions, Performance Rights will accelerate vesting and will automatically convert into Shares on a one-for-one basis.

(o) **Deferral of conversion if resulting in a prohibited acquisition of Shares**

If the conversion of a Performance Right under paragraphs (c) or (n) would result in any person being in contravention of section 606(1) of the *Corporations Act 2001 (Cth)* (**General Prohibition**) then the conversion of that Performance Right shall be deferred until such later time or times that the conversion would not result in a contravention of the General Prohibition. In assessing whether a conversion of a Performance Right would result in a contravention of the General Prohibition:

(i) holders may give written notification to the Company if they consider that the conversion of a Performance Right may result in the contravention of the General Prohibition. The absence of such written notification from the holder will entitle the Company to assume the conversion of a Performance Right will not result in any person being in contravention of the General Prohibition; and

(ii) the Company may (but is not obliged to) by written notice to a holder request a holder to provide the written notice referred to in paragraph (o)(i) within 7 days if the Company considers that the conversion of a Performance Right may result in a contravention of the General Prohibition. The absence of such written notification from the holder will entitle the Company to assume the conversion of a Performance Right will not result in any person being in contravention of the General Prohibition.

(p) **No rights to return of capital**

A Performance Right does not entitle the holder to a return of capital, whether in a winding of capital or otherwise.

(q) **Rights on winding up**

A Performance Right does not entitle the holder to participate in the surplus profits or assets of the Company upon winding up.

(r) **ASX Listing Rule compliance**

The Board reserves the right to amend any term of the Performance Rights to ensure compliance with the ASX Listing Rules.

(s) **No other rights**

A Performance Right gives the holder no rights other than those expressly provided by these terms and conditions and those provided at law where such rights at law cannot be excluded by these terms.

10.5 Employee Incentive Plan

The Company has adopted an employee incentive plan (**Incentive Plan**) to allow eligible participants to be granted Securities in the Company. The material terms of the Incentive Plan are summarised below:

Eligible Participant	**Eligible Participant** means a person that is a 'primary participant' (as that term is defined in Division 1A of Part 7.12 of the Corporations Act) in relation to the Company or an Associated Body Corporate (as defined in the Corporations Act) and has been determined by the Board to be eligible to participate in the Plan from time to time.
Purpose	The purpose of the Plan is to: (a) assist in the reward, retention and motivation of Eligible Participants; (b) link the reward of Eligible Participants to Shareholder value creation; and (c) align the interests of Eligible Participants with shareholders of the Group (being the Company and each of its Associated Bodies Corporate), by providing an

	opportunity to Eligible Participants to receive an equity interest in the Company in the form of Securities.
Maximum number of Convertible Securities	The Company will not make an invitation under the Plan which involves monetary consideration if the number of Shares that may be issued, or acquired upon exercise of Convertible Securities offered under an invitation, when aggregated with the number of Shares issued or that may be issued as a result of all invitations under the Plan during the 3 year period ending on the day of the invitation, will exceed 10% of the total number of issued Shares at the date of the invitation (unless the Constitution specifies a different percentage and subject to any limits approved by Shareholders under Listing Rule 7.2 Exception 13(b). The maximum number of equity securities proposed to be issued under the Plan in reliance on Listing Rule 7.2 (Exemption 13(a)) is 5,000,000 Securities. It is not envisaged that the maximum number of Securities will be issued immediately.
Plan administration	The Plan will be administered by the Board. The Board may exercise any power or discretion conferred on it by the Plan rules in its sole and absolute discretion (except to the extent that it prevents the Participant relying on the deferred tax concessions under Subdivision 83A-C of the Income Tax Assessment Act 1997 (Cth)). The Board may delegate its powers and discretion.
Eligibility, invitation and application	The Board may from time to time determine that an Eligible Participant may participate in the Plan and make an invitation to that Eligible Participant to apply for any (or any combination of) the Securities provided under the Plan on such terms and conditions as the Board decides. On receipt of an invitation, an Eligible Participant may apply for the Securities the subject of the invitation by sending a completed application form to the Company. The Board may accept an application from an Eligible Participant in whole or in part. If an Eligible Participant is permitted in the invitation, the Eligible Participant may, by notice in writing to the Board, nominate a party in whose favour the Eligible Participant wishes to renounce the invitation.
Grant of Securities	The Company will, to the extent that it has accepted a duly completed application, grant the Participant the relevant number and type of Securities, subject to the terms and conditions set out in the invitation, the Plan rules and any ancillary documentation required.
Rights attaching to Convertible Securities	A **Convertible Security** represents a right to acquire one or more Plan Shares in accordance with the Plan (for example, an Option or a Performance Right). Prior to a Convertible Security being exercised, the holder: (a) does not have any interest (legal, equitable or otherwise) in any Share the subject of the Convertible Security other than as expressly set out in the Plan; (b) is not entitled to receive notice of, vote at or attend a meeting of the shareholders of the Company; (c) is not entitled to receive any dividends declared by the Company; and (d) is not entitled to participate in any new issue of Shares (see Adjustment of Convertible Securities section below).
Restrictions on dealing with Convertible Securities	Convertible Securities issued under the Plan cannot be sold, assigned, transferred, have a security interest granted over or otherwise dealt with unless in Special Circumstances as defined under the Plan (including in the case of death or total or permanent

	disability of the holder) with the consent of the Board in which case the Convertible Securities may be exercisable on terms determined by the Board. A holder must not enter into any arrangement for the purpose of hedging their economic exposure to a Convertible Security that has been granted to them.
Vesting of Convertible Securities	Any vesting conditions applicable to the Convertible Securities will be described in the invitation. If all the vesting conditions are satisfied and/or otherwise waived by the Board, a vesting notice will be sent to the Participant by the Company informing them that the relevant Convertible Securities have vested. Unless and until the vesting notice is issued by the Company, the Convertible Securities will not be considered to have vested. For the avoidance of doubt, if the vesting conditions relevant to a Convertible Security are not satisfied and/or otherwise waived by the Board, that security will lapse.
Forfeiture of Convertible Securities	Convertible Securities will be forfeited in the following circumstances: (a) where a Participant acts fraudulently, dishonestly, negligently, in contravention of any Group policy or wilfully breaches their duties to the Group and the Board exercises its discretion to deem some or all of the Performance Rights held by a Participant to have been forfeited; (b) where there is a failure to satisfy the vesting conditions in accordance with the Plan; (c) on the date the Participant becomes insolvent; or (d) on the Expiry Date, subject to the discretion of the Board.
Listing of Convertible Securities	Convertible Securities granted under the Plan will not be quoted on the ASX or any other recognised exchange. The Board reserves the right in its absolute discretion to apply for quotation of Convertible Securities granted under the Plan on the ASX or any other recognised exchange.
Exercise of Convertible Securities and cashless exercise	To exercise a security, the Participant must deliver a signed notice of exercise (Exercise Notice) and, subject to a cashless exercise (see next paragraph below), pay the exercise price (if any) to or as directed by the Company, at any time following vesting of the Convertible Securities (if subject to vesting conditions) and prior to the expiry date as set out in the invitation or vesting notice. In the case of Options, subject to the Board's approval, in lieu of paying the aggregate exercise price specified in the Exercise Notice, the Participant may elect a cashless exercise (Cashless Exercise) whereby the Board will issue to the Participant that number of Shares (rounded down to the nearest whole number) calculated in accordance with the following formula: $S=O*\frac{(MVS-EP)}{MVS}$ Where: S = number of Shares to be issued on the exercise of the Options. O = number of Options being exercised. MVS = market value of shares, being the volume weighted average price per Share traded on the ASX over the five trading days immediately preceding the date of exercise.

	EP = Exercise Price of the Options. For the avoidance of doubt, if the sum of the above calculation is zero or negative, then the holder will not be entitled to use Cashless Exercise. Convertible Securities may not be exercised unless and until that security has vested in accordance with the Plan rules, or such earlier date as set out in the Plan rules.
Timing of issue of Shares and quotation of Shares on exercise	Within five business days after the issue of a valid notice of exercise by a Participant, the Company will issue or cause to be transferred to that Participant the number of Shares to which the Participant is entitled under the Plan rules and issue a substitute certificate for any remaining unexercised Convertible Securities held by that Participant.
Restriction periods and restrictions on transfer of Shares on exercise	If the invitation provides that any Shares issued upon the valid exercise of a Convertible Security are subject to any restrictions as to the disposal or other dealing by a Participant for a period, the Board may implement any procedure it deems appropriate to ensure the compliance by the Participant with this restriction. Additionally, Shares issued on exercise of the Convertible Securities are subject to the following restrictions: (a) if the Company is required but is unable to give ASX a notice that complies with section 708A(5)(e) of the Corporations Act, Shares issued on exercise of the Convertible Securities may not be traded until 12 months after their issue unless the Company, at its sole discretion, elects to issue a prospectus pursuant to section 708A(11) of the Corporations Act; (b) all Shares issued on exercise of the Convertible Securities are subject to restrictions imposed by applicable law on dealing in Shares by persons who possess material information likely to affect the value of the Shares and which is not generally available; and (c) all Shares issued on exercise of the Convertible Securities are subject to the terms of the Company's Securities Trading Policy.
Rights attaching to Shares on exercise	All Shares issued upon exercise of Convertible Securities will rank equally in all respects with the then Shares of the Company.
Change of control	If a change of control event occurs (being an event which results in any person (either alone or together with associates) owning more than 50% of the Company's issued capital), unvested Convertible Securities will vest unless the Board determines in its discretion otherwise. The Board's discretion in determining the treatment of any unvested Convertible Securities on a change of control event is limited to vesting or varying any vesting conditions in respect to the Convertible Securities and does not include a discretion to lapse or forfeit unvested Convertible Securities for less than fair value.
Participation in entitlements and bonus issues	Subject always to the rights under the following two paragraphs, Participants will not be entitled to participate in new issues of capital offered to holders of Shares such as bonus issues and entitlement issues.
Adjustment for bonus issue	If Shares are issued by the Company by way of bonus issue (other than an issue in lieu of dividends or by way of dividend reinvestment), the Participant is entitled, upon exercise of the Convertible Securities, to receive an issue of as many additional Shares as would have been issued to the holder if the holder held

	Shares equal in number to the Shares in respect of which the Convertible Securities are exercised.
Reorganisation	If there is a reorganisation of the issued share capital of the Company (including any subdivision, consolidation, reduction, return or cancellation of such issued capital of the Company), the rights of each Participant holding Convertible Securities will be changed to the extent necessary to comply with the ASX Listing Rules applicable to a reorganisation of capital at the time of the reorganisation.
Buy-Back	Subject to applicable law, the Company may at any time buy-back Securities in accordance with the terms of the Plan.
Employee Share Trust	The Board may in its sole and absolute discretion use an employee share trust or other mechanism for the purposes of holding Convertible Securities for holders under the Plan and delivering Shares on behalf of holders upon exercise of Convertible Securities.
Amendment of Plan	Subject to the following paragraph, the Board may at any time amend any provisions of the Plan rules, including (without limitation) the terms and conditions upon which any Securities have been granted under the Plan and determine that any amendments to the Plan rules be given retrospective effect, immediate effect or future effect. No amendment to any provision of the Plan rules may be made if the amendment materially reduces the rights of any Participant as they existed before the date of the amendment, other than an amendment introduced primarily for the purpose of complying with legislation or to correct manifest error or mistake, amongst other things, or is agreed to in writing by all Participants.
Plan duration	The Plan continues in operation until the Board decides to end it. The Board may from time to time suspend the operation of the Plan for a fixed period or indefinitely and may end any suspension. If the Plan is terminated or suspended for any reason, that termination or suspension must not prejudice the accrued rights of the Participants. If a Participant and the Company (acting by the Board) agree in writing that some or all of the Securities granted to that Participant are to be cancelled on a specified date or on the occurrence of a particular event, then those Securities may be cancelled in the manner agreed between the Company and the Participant.
Income Tax Assessment Act	The Plan is a plan to which Subdivision 83A-C of the Income Tax Assessment Act 1997 (Cth) applies (subject to the conditions in that Act) except to the extent an invitation provides otherwise.
Withholding	If the Company, trustee, or Plan administrator must account for tax or superannuation amounts for a Participant (Withholding Amount), it may withhold or be reimbursed by the Participant. To recover the Withholding Amount, the Company, trustee, or Plan administrator may sell the Participant's shares, deduct it from salary, forfeit securities, or make other payment arrangements.

Directors are entitled to participate in the Incentive Plan and propose to participate in the Incentive Plan through the issue of the Performance Rights as set out in further detail in Sections 10.6 and 10.7 below.

10.6 ASX confirmation and waivers

The Company has sought advice from ASX regarding the following confirmation and waivers from ASX:

(a) confirmation that the terms of the 3,900,000 Performance Rights proposed to be issued as set out in Section 10.4 to Messrs Hancock, Todd, Collins, Chan and

McGoldrick, are appropriate and equitable for the purposes of Listing Rule 6.1; and

(b) a waiver from Listing Rule 1.1 Condition 12 to the extent necessary to permit the Company to have on issue the Performance Rights to be issued to Messrs Hancock, Todd, Collins, Chan and McGoldrick on the terms set out in Section 10.4.

For the purposes of the confirmations sought from ASX as set out in Section 10.6(a), the Company confirms that:

(a) an aggregate of 3,900,000 Performance Rights will be issued under the Management Offer to Messrs Hancock, Todd, Collins, Chan and McGoldrick (or their respective nominees) as detailed in Section 4.7;

(b) the relationship of each of the recipients of the Performance Rights is as follows:

(i) Messrs Hancock, Todd and Collins are directors of the Company;

(ii) Mr Chan is proposed to be appointed to the role of Chief Financial Officer; and

(iii) Mr McGoldrick is proposed to provide services on an ad hoc basis as a consultant to the Company;

(c) the Performance Rights are being issued to remunerate and incentivise Messrs Hancock, Todd, Collins, Chan and McGoldrick;

(d) the remuneration packages of Mr Hancock, Mr Todd and Mr Collins are detailed in Section 8.4. Mr Chan is expected to receive $302,500 per annum in the role of Chief Financial Officer and Mr McGoldrick will receive fees on an ad hoc basis;

(e) Mr Hancock, Mr Todd and Mr Collins hold securities in the Company as set out in Section 8.4. Mr Chan holds 47,052 Shares and Mr McGoldrick holds nil Shares;

(f) the purpose of the issue of the Performance Rights is to provide a performance linked incentive component in the remuneration packages for Messrs Hancock, Todd, Collins, Chan and McGoldrick to motivate and reward their performances in their respective roles and to provide cost effective remuneration to Messrs Hancock, Todd, Collins, Chan and McGoldrick, enabling the Company to spend a greater proportion of its cash reserves on its operations than it would if alternative cash forms of remuneration were given;

(g) the number of Performance Rights to be issued to each of the recipients has been determined based upon a consideration of:

(i) current market practices of ASX listed companies of a similar size and stage of development to the Company;

(ii) the remuneration of the recipients; and

(iii) incentives to attract and retain the services of the recipients while preserving the Company's cash reserves.

(h) the Company considers the number of Performance Rights to be issued to be appropriate and reasonable based upon these considerations and does not consider that there are any significant opportunity costs to the Company or benefits foregone by the Company in issuing the Performance Rights upon the terms proposed;

(i) if the milestones attaching to the Performance Rights to be issued to Messrs Hancock, Todd, Collins, Chan and McGoldrick are met and the Performance Rights are converted, a total of 3,900,000 Shares would be issued. This would increase the number of Shares on issue from 39,700,408 Shares (on an undiluted basis) to 43,600,408 Shares; and

(j) the Performance Rights will be issued on the terms and conditions set out in Section 10.4.

10.7 Interests of Directors

Other than as set out in this Prospectus, no Director or proposed Director holds, or has held within the 2 years preceding lodgement of this Prospectus with the ASIC, any interest in:

(a) the formation or promotion of the Company;

(b) any property acquired or proposed to be acquired by the Company in connection with:

(i) its formation or promotion; or

(ii) the Public Offer; or

(c) the Public Offer,

and no amounts have been paid or agreed to be paid and no benefits have been given or agreed to be given to a Director or proposed Director:

(d) as an inducement to become, or to qualify as, a Director; or

(e) for services provided in connection with:

(i) the formation or promotion of the Company; or

(ii) the Public Offer.

10.8 Interests of Experts and Advisers

Other than as set out below or elsewhere in this Prospectus, no:

(a) person named in this Prospectus as performing a function in a professional, advisory or other capacity in connection with the preparation or distribution of this Prospectus;

(b) promoter of the Company; or

(c) underwriter (but not a sub-underwriter) to the issue or a financial services licensee named in this Prospectus as a financial services licensee involved in the issue,

holds, or has held within the 2 years preceding lodgement of this Prospectus with the ASIC, any interest in:

(d) the formation or promotion of the Company;

(e) any property acquired or proposed to be acquired by the Company in connection with:

(i) its formation or promotion; or

(ii) the Public Offer; or

(f) the Public Offer,

and no amounts have been paid or agreed to be paid, and no benefits have been given or agreed to be given to any of these persons for services provided in connection with:

(g) the formation or promotion of the Company; or

(h) the Public Offer.

ERCE Australia Pty Ltd (**ERCE**) has acted as Independent Technical Specialist and has prepared the Independent Technical Specialist's Report which is included in Annexure A. The Company estimates it will pay ERCE a total of $120,000 (excluding GST) for these services. During the 24 months preceding lodgement of this Prospectus with the ASIC, ERCE has received $116,000 in fees from the Company.

HLB Mann Judd has acted as Investigating Accountant and has prepared the Independent Limited Assurance Report which is included in Annexure C. The Company estimates it will pay HLB Mann Judd a total of $20,000 (excluding GST) for these services.

HLB Mann Judd has been appointed as the Company's auditor. The Company estimates it will pay HLB Mann Judd a total of $20,000 (excluding GST) for the audit for the year ending 30 June 2026. During the 24 months preceding lodgement of this Prospectus with the ASIC, HLB Mann Judd has received no fees from the Company for audit services.

Powerhouse Advisory Australia Pty Ltd has acted as the Lead Manager to the Public Offer and will receive 6% of the gross proceeds raised under the Public Offer following the successful completion of the Public Offer. The Lead Manager will be responsible for paying all capital raising fees that the Lead Manager and the Company agree with any other financial service licensees. Further details in respect to the Lead Manager Mandate with Powerhouse are summarised in Section 9.1. During the 24 months preceding lodgement of this Prospectus with the ASIC, Powerhouse has not received any fees from the Company.

Salient Corporate Pty Ltd has acted as corporate advisor to the Company and will receive the fees summarised in Section 9.1. During the 24 months preceding lodgement of this Prospectus with the ASIC, Salient Corporate has not received any fees from the Company.

Steinepreis Paganin has acted as the Australian legal adviser to the Company in relation to the Public Offer. The Company estimates it will pay Steinepreis Paganin $120,000 (excluding GST) for these services. Subsequently, fees will be charged in accordance with normal charge out rates. During the 24 months preceding lodgement of this Prospectus with the ASIC, Steinepreis Paganin has not received any fees from the Company.

Parada Rivera Evardone & Salalima Attorneys-at-Law (**PRESLAW**) has prepared the Solicitor's Report on Title which is included in Annexure B. The Company estimates it will pay PRESLAW $5,000 (excluding GST) for these services. During the 24 months preceding lodgement of this Prospectus with the ASIC, PRESLAW has not received any fees from the Company for other services.

10.9 Consents

Chapter 6D of the Corporations Act imposes a liability regime on the Company (as the offeror of the Shares), the Directors, any persons named in this Prospectus with their consent as proposed Directors, any underwriters, persons named in this Prospectus with their consent having made a statement in this Prospectus and persons involved in a contravention in relation to this Prospectus, with regard to misleading and deceptive statements made in this Prospectus. Although the Company bears primary responsibility for this Prospectus, the other parties involved in the preparation of this Prospectus can also be responsible for certain statements made in it.

Each of the parties referred to in this Section:

(a) does not make, or purport to make, any statement in this Prospectus other than those included in this Prospectus with the consent of that party as specified in this Section;

(b) has not authorised or caused the issue of this Prospectus and makes no representation or warranty, express or implied, as to the fairness, accuracy or completeness of the information contained in this Prospectus;

(c) in light of the above, only to the maximum extent permitted by law, expressly disclaim and take no responsibility for any part of this Prospectus other than a reference to its name and a statement included in this Prospectus with the consent of that party as specified in this Section; and

(d) has not withdrawn its consent prior to the lodgement of this Prospectus with the ASIC.

ERCE Australia Pty Ltd has given its written consent to being named as Independent Technical Specialist in this Prospectus, and to the inclusion of the Independent Technical Specialist's Report in Annexure A in the form and context in which the report is included.

HLB Mann Judd has given its written consent to being named as Investigating Accountant in this Prospectus and to the inclusion of the Independent Limited Assurance Report in Annexure C in the form and context in which the information and report is included.

HLB Mann Judd has given its written consent to being named as auditor of the Company in this Prospectus.

Parada Rivera Evardone & Salalima Attorneys-at-Law has given its written consent for the inclusion of the Solicitor's Report on Title in Annexure B in the form and context in which the report is included.

Steinepreis Paganin has given its written consent to being named as the Australian legal advisers to the Company in relation to the Public Offer in this Prospectus.

Powerhouse Advisory Australia Pty Ltd has given its written consent to being named as the Lead Manager to the Public Offer in this Prospectus in the form and context in which it is named.

Salient Corporate Pty Ltd has given its written consent to being named as corporate advisor to the Company in this Prospectus in the form and context in which it is named.

Automic Group has given its written consent to being named as the share registry to the Company in this Prospectus.

10.10 Expenses of the Public Offer

The total expenses of the Public Offer (excluding GST) are estimated to be approximately $627,282 and are expected to be applied towards the items set out in the table below:

ITEM OF EXPENDITURE	($)
ASIC Fees	3,206
ASX Fees	84,076
Lead Manager Fees	240,000
Legal Fees1	125,000
Independent Technical Specialist Fees	120,000
Investigating Accountant Fees	20,000
Financial accounting consultant	10,000
Miscellaneous	25,000
Total	**627,282**

Notes:

1. Includes fees payable to Steinepreis Paganin and Parada Rivera Evardone & Salalima Attorneys-at-Law.

11. DIRECTORS' AUTHORISATION

This Prospectus is issued by the Company, and its issue has been authorised by a resolution of the Directors.

In accordance with section 720 of the Corporations Act, each Director has consented to the lodgement of this Prospectus with the ASIC.

12. GLOSSARY

Where the following terms are used in this Prospectus they have the following meanings:

$ means an Australian dollar.

Admission means the admission of the Company to the Official List.

Advisor Offer means the offer of 1,250,000 Options to Salient Corporate Pty Ltd (or their nominees).

Application Form means the application form accompanying this Prospectus (including an online application form) relating to an Offer.

ASIC means Australian Securities & Investments Commission.

ASX means ASX Limited (ACN 008 624 691) or the financial market operated by it as the context requires.

ASX Listing Rules means the official listing rules of ASX.

Board means the board of Directors as constituted from time to time.

Business Days means Monday to Friday inclusive, except New Year's Day, Good Friday, Easter Monday, Christmas Day, Boxing Day, and any other day that ASX declares is not a business day.

CHESS means the Clearing House Electronic Subregister System operated by ASX Settlement.

Closing Date means the closing date of the Public Offer as set out in the indicative timetable in the Key Public Offer Information Section (subject to the Company reserving the right to extend the Closing Date or close the Public Offer early).

Company means Tetragon Energy Limited (ACN 684 303 660).

Conditions has the meaning set out in Section 4.8.

Constitution means the constitution of the Company.

Corporations Act means *the Corporations Act 2001* (Cth).

Directors means the directors of the Company at the date of this Prospectus.

Exposure Period means the period of 7 days after the date of lodgement of this Prospectus, which period may be extended by the ASIC by not more than 7 days pursuant to section 727(3) of the Corporations Act.

ESG means Environmental, Social and Governance as set out in Section 8.7.

In-specie Distribution has the meaning set out in Section 5.1.

Institutional Investor means:

(a) a "professional investor" (as defined in the Securities and Futures Ordinance of Hong Kong, Chapter 571 of the Laws of Hong Kong);

(b) an "institutional investor" or an "accredited investor" (as such terms are defined in the Securities and Futures Act 2001 of Singapore; and

(c) a qualified buyer in an exempt transaction under section 10.1(l) of the Philippine Securities Regulation Code.

Lead Manager or **Powerhouse** means Powerhouse Advisory Australia Pty Ltd (ARN 1311 365).

Lead Manager Mandate means the agreement with the Lead Manager summarised in Section 9.1.

Lead Manager Offer means the offer of 2,000,000 Options to the Lead Manager (or its nominees).

LNG means liquefied natural gas.

Management Offer means the offer of 3,900,000 Performance Rights to certain Directors and senior management of the Company (or their nominees).

Minimum Subscription means the total amount to be raised under the Public Offer, being $4,000,000.

Offers means the Public Offer and the Secondary Offers.

Official List means the official list of ASX.

Official Quotation means official quotation by ASX in accordance with the ASX Listing Rules.

Option means an option to acquire a Share.

Performance Right means a performance right convertible into a Share issued on the terms and conditions set out in Section 10.4.

Projects has the meaning set out in Section 5.1.

Prospectus means this prospectus.

Public Offer means the offer of Shares pursuant to this Prospectus as set out in Section 4.2.

Public Offer Price means $0.20 per Share.

Recommendations has the meaning set out in Section 8.6.

Salient Corporate means Salient Corporate Pty Ltd (AFSL 499 098).

Secondary Offers means the Lead Manager Offer, Management Offer and the Advisor Offer.

Section means a section of this Prospectus.

Securities means Shares, Options and/or Performance Rights, as the context requires.

Share means a fully paid ordinary share in the capital of the Company.

Shareholder means a holder of Shares.

Spin-out has the meaning set out in Section 5.1.

Tetragon Philippines means Tetragon Energy (Philippines) Pty Ltd (ACN 655 451 095).

Triangle means Triangle Energy (Global) Limited (ACN 110 411 428).

US means the United States of America.

WA means Western Australia.

Winchester means Winchester Energy Limited.

WST means Western Standard Time as observed in Perth, Western Australia.

Tetragon Energy Ltd
A Review of Gas Discoveries and Undrilled Prospects and Leads in Blocks SC-80, SC-81 and SC-82, Philippines

Prepared For: Tetragon Energy Limited

By: Sproule ERCE

Date: 11 May 2026

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Table of Contents

1 Executive Summary **13**

1.1 Assets Overview and Highlights 13

1.2 Contingent Resources 14

1.3 Prospective Resources 15

1.4 Leads 17

2 Introduction **18**

2.1 Assets Summary 18

2.2 Work Completed 20

3 Sandakan Basin, Sulu Sea: SC-80 and SC-81 **21**

3.1 Introduction 21

3.2 Exploration History 23

3.3 Data Provided 25

3.4 Geological Overview 25

3.5 Hydrocarbon Discoveries Dabakan and Palendag 27

3.5.1 Geophysics Overview 28

3.5.2 Seismic Interpretation 29

3.5.3 Petrophysics 33

3.5.4 Reservoir Engineering 37

3.5.5 Hydrocarbons Initially in Place and Contingent Resources 44

3.5.6 Summary of Contingent Resources 59

3.6 Prospective Resources 60

3.6.1 Estimation of HIIP and Prospective Resources 61

3.6.2 Block SC-80 Prospective Resources 63

3.6.3 Block SC-81 Prospective Resources 74

3.6.4 Risk (Chance of Success) - Sandakan Basin 78

3.7 Leads 78

3.7.1 Block SC-80 Leads 80

3.7.2 Block SC-81 Leads 86

4 Cagayan Basin: Block SC-82 **89**

4.1 Introduction 89

4.2 Exploration History 91

4.3 Data Provided 92

4.4 Geological Overview 93

4.4.1 Petroleum System 95

4.5 Hydrocarbon Discoveries 96

4.5.1 San Antonio Gas Field 96

4.5.2 Nassiping Area 96

4.6 Geophysics Overview 97

4.6.1 Seismic Interpretation 97

4.6.2 Petrophysics 100

4.7 Reservoir Engineering 100

4.8 Volumetric Analysis 102

4.8.1 Estimation of HIIP - Nassiping Area 102

4.8.2 Risk (Chance of Success) - Cagayan Basin 110

4.9 Leads 111

Appendix 1: SPE PRMS Guidelines **117**

Appendix 2: Nomenclature **139**

Tables

Table 1-1: Unrisked Gas Contingent Resources as of 31 March 2026 15
Table 1-2: Unrisked Condensate Contingent Resources as of 31 March 2026 15
Table 1-3: Gross Unrisked Prospective Resources as of 31 March 2026 16
Table 2-1: Tetragon Energy's Licence Interests 20
Table 3-1: Tetragon Energy: SC-80 Work programme summary 22
Table 3-2: Wells drilled in SC-80 and SC-81 24
Table 3-3: 2D and 3D seismic data 28
Table 3-4: MDT mobility estimates for Wells Dabakan-1 and Palendag-1A 38
Table 3-5: Fluid properties for Dabakan 41
Table 3-6: Fluid properties for Palendag 42
Table 3-7: Recovery Factors for Dabakan 43
Table 3-8: Recovery Factors for Palendag 44
Table 3-9: Dabakan Summary of GIIP, CIIP, Unrisked Gas and Condensate Contingent Resources 45
Table 3-10: Palendag Summary of GIIP, CIIP, Unrisked Gas and Condensate Contingent Resources 45
Table 3-11: Input parameters for Dabakan L300 S1 47
Table 3-12: Dabakan L300 S1 GIIP, Unrisked Gas Contingent Resources and CIIP 47
Table 3-13: Input parameters for Dabakan L225 S1 48
Table 3-14: Dabakan L225 S1 GIIP, Unrisked Gas Contingent Resources and CIIP 48
Table 3-15: Input parameters for Dabakan L225 S2 49
Table 3-16: Dabakan L225 S2 GIIP, Unrisked Gas Contingent Resources and CIIP 49
Table 3-17: Input parameters for Dabakan L100 Intra 50
Table 3-18: Dabakan L100 Intra GIIP, Unrisked Gas Contingent Resources and CIIP 50
Table 3-19: Input parameters for Dabakan L100 S2 51
Table 3-20: Dabakan L100 S2 GIIP, Unrisked Gas Contingent Resources and CIIP 51
Table 3-21: Input parameters for Dabakan L100 S3 52
Table 3-22: Dabakan L100 S3 GIIP, Unrisked Gas Contingent Resources and CIIP 53
Table 3-23: Input parameters for Dabakan L80 54

Table 3-24: Dabakan L80 GIIP, Unrisked Gas Contingent Resources and CIIP 54
Table 3-25: Input parameters for Palendag L60 55
Table 3-26: Palendag L60 GIIP, Unrisked Gas Contingent Resources and CIIP 55
Table 3-27: Input parameters for Palendag L50 56
Table 3-28: Palendag L50 GIIP, Unrisked Gas Contingent Resources and CIIP 56
Table 3-29: Input parameters for Palendag L40 S2 57
Table 3-30: Palendag L40 S2 GIIP, Unrisked Gas Contingent Resources and CIIP 58
Table 3-31: Input parameters for Palendag L20 59
Table 3-32: Palendag L20 GIIP, Unrisked Gas Contingent Resources and CIIP 59
Table 3-33: Unrisked Gas Contingent Resources as of 31 March 2026 59
Table 3-34: Unrisked Condensate Contingent Resources as of 31 March 2026 60
Table 3-35: Summary of SC-80 prospects, GIIP and Unrisked Gas Prospective Resources 62
Table 3-36: Summary of SC-81 prospects, GIIP and Unrisked Gas Prospective Resources 62
Table 3-37: Summary of SC-81 prospects STOIIP and Unrisked Oil Prospective Resources 63
Table 3-38: Labo L1 and Labo L2 areas 66
Table 3-39: Labo L3 areas 67
Table 3-40: Input parameters for Labo L1, L2 and L3 67
Table 3-41: Kabuyao prospects area 70
Table 3-42: Input parameters for Kabuyao prospects 70
Table 3-43: Halcon 5C area 72
Table 3-44: Input parameters for Halcon 5C 73
Table 3-45: Aardvark prospect area 77
Table 3-46: Input Parameters for Aardvark 77
Table 3-47: Evaluation Risk for Labo, Kabuyao, Halcon and Aardvark prospects 78
Table 3-48: Lead in Blocks SC-80 and SC-81 79
Table 4-1: Tetragon Energy: Work programme summary 90
Table 4-2: Summary of GIIP for Nassiping discovery 103
Table 4-3: Unrisked Gas Contingent Resources for Nassiping discovery 103
Table 4-4: Summary of GIIP and Unrisked Gas Prospective Resources 104
Table 4-5: Input parameters for Callao B 106

Table 4-6: Input parameters for Near Callao A 107
Table 4-7: Input parameters for Upper Sicalao Reef (above Sicalao C) 108
Table 4-8: Inputs parameters between Sicalao C and B 109
Table 4-9: Inputs parameters between Sicalao B and A 110
Table 4-10: Evaluation risk for Sicalao prospect 111
Table 4-11: Leads in Block SC-82 112

Figures

Figure 2-1: Block SC-80 and SC-81 location map 18
Figure 2-2: Block SC-82 location map 19
Figure 3-1: Blocks SC-80 and SC-81 water depth map 21
Figure 3-2: Wells drilled in SC-80 and SC-81 *Source: Tetragon Energy* 23
Figure 3-3: Stratigraphy, Petroleum System & Plays of the Sandakan Basin 27
Figure 3-4: Schematic geo-seismic line through Dabakan and Palendag 28
Figure 3-5: Seismic coverage over Blocks SC-80 and SC-81 29
Figure 3-6: Seismic line through Well Dabakan-1 30
Figure 3-7: Seismic line through Well Palendag-1A 30
Figure 3-8: Pre-stack modelling and AVO analysis of Well Dabakan-1 at the L100 S1 sand interval using the in-situ fluid 32
Figure 3-9: Pre-stack modelling and AVO analysis of Well Dabakan-1 at the L100 S1 sand interval using the fully substituted brine 32
Figure 3-10: Wedge modelling using Well Dabakan-1 logs on nears (centred at 12 degrees) and fars (centred at 35 degrees) 33
Figure 3-11: CPI for Well Dabakan-1 35
Figure 3-12: CPI for Well Palendag-1A 36
Figure 3-13: CPI for Well Wildebeest-1 37
Figure 3-14: Dabakan-1 MDT pressures over all intervals 39
Figure 3-15: Dabakan-1 MDT pressures over L100 S2 sands 39
Figure 3-16: Palendag-1 RDT pressures over all intervals 40
Figure 3-17: Well Dabakan-1 L300 S1 CPI 46
Figure 3-18: Dabakan L300 S1 amplitude extraction and volumetric polygons 46

Figure 3-19: Well Dabakan-1 L225 S1 CPI 47
Figure 3-20: Dabakan L225 S1 amplitude extraction and volumetric polygons 48
Figure 3-21: Well Dabakan-1 L225 S2 CPI 49
Figure 3-22: Well Dabakan-1 L100 Intra CPI 49
Figure 3-23: Dabakan L100 Intra amplitude extraction and volumetric polygons 50
Figure 3-24: Well Dabakan-1 L100 S2 CPI 51
Figure 3-25: Dabakan L100 S2 amplitude extraction and volumetric polygons 51
Figure 3-26: Well Dabakan-1 L100 S3 CPI 52
Figure 3-27: Dabakan L 100 S3 amplitude extraction and volumetric polygons 52
Figure 3-28: Well Dabakan-1 L80 CPI 53
Figure 3-29: Dabakan L80 amplitude extraction and volumetric polygons 53
Figure 3-30: Well Palendag-1A L60 CPI 54
Figure 3-31: Palendag L60 amplitude extraction and volumetric polygons 55
Figure 3-32: Well Palendag-1A L50 CPI 56
Figure 3-33: Palendag L50 amplitude extraction and volumetric polygons 56
Figure 3-34: Well Palendag-1A L40 S2 CPI 57
Figure 3-35: Palendag L40 S2 amplitude extraction and volumetric polygons 57
Figure 3-36: Well Palendag-1A L20 CPI 58
Figure 3-37: Palendag L20 amplitude extraction and volumetric polygons 59
Figure 3-38: Location of SC-80 discoveries and prospects 64
Figure 3-39: Crossline showing the intervals for Labo, Kabuyao and Palendag 65
Figure 3-40: A) RMS amplitude extraction. B) Inline showing Labo L1 and Labo L2 prospects 65
Figure 3-41: Maximum amplitude map for Labo prospect. A) Labo L1. B) Labo L2. 66
Figure 3-42: Labo L3 maximum amplitude map 67
Figure 3-43: Arbitrary line showing Kabuyao and Labo prospects and Dabakan discovery 68
Figure 3-44: Maximum amplitude map for Kabuyao prospect A) Kabuyao Kab-100. B) Kabuyao Kab-120. C) Kabuyao Kab-160. D) Kabuyao Kab-180. 69
Figure 3-45: Crossline 7255 showing Halcon 5C 71
Figure 3-46: RMS amplitude map for Halcon prospect 72
Figure 3-47: Halcon RMS amplitude of Crossline 7251 73

Figure 3-48: Map showing the location of SC-81 and SC-80 Blocks, the extension of the 3D and 2D seismic and the location of the prospects in the area 74

Figure 3-49: Arbitrary line showing the Aardvark prospect 75

Figure 3-50: Aardvark RMS amplitude map 76

Figure 3-51: RMS amplitude of Inline 1680 77

Figure 3-52: Maximum amplitude map showing the Labo L3 West lead next to the Labo L3 prospect 80

Figure 3-53: Maximum amplitude map showing the Kabuyao K 181 lead 81

Figure 3-54: Maximum amplitude map showing Luntang lead. A) Luntang 0. B) Luntang 1. C) Luntang 2. D) Luntang 3 82

Figure 3-55: Maximum amplitude map showing the Matutum lead. A) Matutum L200 B) Matutum L300 83

Figure 3-56: Maximum amplitude map showing the Halcon 4E and 4W 84

Figure 3-57: Maximum amplitude map showing the Mirador lead. A) Mirador 4. B) Mirador L5C 84

Figure 3-58: Maximum amplitude map showing the Samat lead. A) Samat 4000. B) Samat 4200. C) Samat 4400. 85

Figure 3-59: Wahoo RMS amplitude map 86

Figure 3-60: Mirapina Balang RMS amplitude map 87

Figure 3-61: Moose West RMS amplitude map 87

Figure 3-62: Depth map showing the Foldbelt location and the mid case areas 88

Figure 4-1: Wells drilled in Block SC-82 and SC-37 89

Figure 4-2: Schematic stratigraphic column of the Cagayan Basin 93

Figure 4-3: Cagayan Basin Plays: Schematic N-S cross-section 95

Figure 4-4: Location of the seismic line B-04 crossing the Wells Nassiping-1 and Nassiping-2 98

Figure 4-5: Seismic line B-04 intersecting Wells Nassiping-1 and Nassiping-2 99

Figure 4-6: Depth conversion result- Callao B depth grid 99

Figure 4-7: Perforated intervals in the Callao A and B 101

Figure 4-8: Well Nassinping-2 flow test 101

Figure 4-9: Depth map (mMD) for Top Callao B 105

Figure 4-10: Seismic Line B-04 illustrating the interpretated stratigraphic horizons 105

Figure 4-11: Depth map (mMD) Near Callao A 106

Figure 4-12: Depth map (mMD) of the Sicalao Upper Reef (above Sicalao C) 107

Figure 4-13: Seismic line B-04 illustrating the interpretated stratigraphic horizons 108

Figure 4-14: Depth map (mMD) between Sicalao C and B Depth Map, showing the GDT (blue line) and structural 109

Figure 4-15: Depth map (mMD) between Sicalao B and A..... 110

Figure 4-16: Leads identified within Block SC-82 111

Figure 4-17: Time- structure map showing the extend of Clastic Rollover lead..... 113

Figure 4-18: Time- structure map showing the extent of the Updip Reef lead..... 114

Figure 4-19: Time- structure map showing the extent of the Pop-up lead. 115

Figure 4-20: Time- structure map showing the extent of the Moundform lead 115

Figure 4-21: Time- structure map showing the extent of the Basement High lead 116

11 May 2026

Mr Conrad Todd and Mr Douglas Gillies

Tetragon Energy Ltd

Suite 2, Ground Floor,

100 Havelock Street, West Perth

WA 6005

Australia

Dear Sirs,

Re: Competent Person's Report – Blocks SC-80 and SC-81 (Offshore Philippines) and Block SC-82 (Onshore Philippines)

In accordance with your instructions, Sproule ERCE Australia Pty Ltd has prepared a Competent Person's Report ("CPR") for the Contingent Resources and Prospective Resources held by Tetragon Energy Ltd ("Tetragon Energy") in Blocks SC-80 and SC-81 located in South Sulu Sea, offshore Philippines and in Block SC-82 located in the Cagayan Basin, onshore Philippines. The CPR has been prepared to support filing on the Australian Stock Exchange (Stock Exchange) and is prepared in accordance with Article 5 of ASX listing rules.

The effective date ("Effective Date") of this report is 31 March 2026. For the preparation of this CPR Sproule ERCE was provided with data and information by Tetragon Energy up to March 2026.

Tetragon Energy has provided written representations that no new data or information have been acquired between the Effective Date and the publication date of this CPR that would materially affect the opinions expressed in this CPR.

Sproule ERCE has carried out this work in accordance with the June 2018 SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE Petroleum Resources Management System ("PRMS") as the standard for classification and reporting. A summary of the PRMS is found in Appendix 1 of the report. The full text can be downloaded from: https://www.spe.org/en/industry/petroleum-resources-management-system-2018/

Nomenclature that may be used in this CPR is summarised in Appendix 2: Nomenclature.

Use of the Report

This CPR is produced solely for the benefit of and on the instructions of Tetragon Energy, and not for the benefit of any third party. Any third party to whom the client discloses or makes available this report shall not be entitled to rely on it or any part of it.

Tetragon Energy agrees to ensure that any publication or use of this report which makes reference to Sproule ERCE shall be published or quoted in its entirety and Tetragon Energy shall not publish or use extracts of this report or any edited or amended version of this report, without the prior written consent of Sproule ERCE. In the case that any part of this report is delivered in digital format, Sproule ERCE does not accept any responsibility for edits carried out by the client or any third party or otherwise after such material has been sent by Sproule ERCE to the client.

Disclaimer

Sproule ERCE has made every effort to ensure that the interpretations, conclusions and recommendations presented in this report are accurate and reliable in accordance with good industry practice. Sproule ERCE does not, however, guarantee the correctness of any such interpretations and shall not be liable or responsible for any loss, costs, damages or expenses incurred or sustained by anyone resulting from any interpretation or recommendation made by any of its officers, agents or employees.

Sproule ERCE has used standard petroleum evaluation techniques in the generation of this report. These techniques combine geophysical and geological knowledge with assessments of porosity and permeability distributions, fluid characteristics, production performance and reservoir pressure. There is uncertainty in the measurement and interpretation of basic data. Sproule ERCE has estimated the degree of this uncertainty and determined the range of petroleum initially in place and recoverable hydrocarbon volumes. In applying these procedures and tests, nothing came to the attention of Sproule ERCE that would suggest that information provided by Tetragon Energy was not complete and accurate. Sproule ERCE reserves the right to review all calculations referred to or included in this report and to revise the estimates in light of erroneous data supplied or information existing but not made available which becomes known subsequent to the preparation of this CPR.

The accuracy of any Contingent Resources and Prospective Resources is a function of the quality and quantity of available data and of engineering interpretation and judgment. While Contingent Resources and Prospective Resources presented herein are considered reasonable, the estimates should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward.

In the case of Contingent Resources presented in this report, there is no certainty that it will be commercially viable to produce any portion of the resources.

In the case of Prospective Resources presented in this report, there is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

No site visits were undertaken in the preparation of this CPR.

Professional Qualifications

Sproule ERCE is an independent consultancy specialising in geoscience evaluation, engineering and economic assessment. Sproule ERCE will receive a fee for the preparation of this report in

accordance with normal professional consulting practices. This fee is not dependent on the findings of this CPR and Sproule ERCE will receive no other benefit for the preparation of this CPR.

Neither Sproule ERCE nor the Competent Person who is responsible for authoring this CPR, nor any Directors of Sproule ERCE have at the date of this report any shareholding in Tetragon Energy. Consequently, Sproule ERCE, the Competent Person and the Directors of Sproule ERCE consider themselves to be independent of Tetragon Energy, its directors and senior management.

Sproule ERCE has the relevant and appropriate qualifications, experience and technical knowledge to appraise professionally and independently the assets. The preparation of this report has been supervised by Mr. Simon McDonald, Principal Strategic Advisor of Sproule ERCE. Mr. McDonald has 49 years of experience in the evaluation of oil and gas fields, preparation of development plans and assessment of reserves and resources. He holds a B. Sc. degree in Civil Engineering from Leeds University and a M. Sc. Degree in Petroleum Engineering from Imperial College, London. He is a Chartered Engineer and member of the Energy Institute, a member of the Society of Petroleum Engineers and of the Society of Petroleum Evaluation Engineers ("SPEE"). He has served as a member of the Board of the SPEE and also as a past President of the SPEE. Mr. McDonald therefore possesses the required competencies, being professionally qualified and a member in good standing of an appropriately recognised professional association.

Yours faithfully,

Signed by:
Simon McDonald
1133426BDEA84F5...

Simon McDonald

Principal Strategic Advisor, Sproule ERCE

1 Executive Summary

Sproule ERCE has estimated Contingent Resources for the Dabakan and Palendag reservoirs located in Block SC-80 and Block SC-81, and for the Callao Limestone reservoir in the anticlinal trap tested by Well Nassiping-2, located in Block SC-82. Sproule ERCE has also estimated Prospective Resources for five undrilled prospects on Blocks SC-80, SC-81 and Block SC-82.

1.1 Assets Overview and Highlights

Palendag and Dabakan Gas Discoveries – Tetragon Energy's Interest 37.5%

The Dabakan and Palendag gas condensate discoveries are located within a deepwater thrust fold-belt play in Block SC-80, in the Sandakan Basin (offshore Philippines). Dabakan was discovered in 2009 by Well Dabakan-1, drilled in a water depth of 1,802 m. Well Dabakan-1 logged gas over eight reservoir sections between ~2,950 mTVDSS and ~4,350 mTVDSS, with Reservoir Description Tool ("RDT") gas condensate samples being recovered from five of these reservoirs.

Palendag was discovered in 2010 by Well Palendag-1A in a water depth of 1,937 m and is located to the east of Well Dabakan-1. Well Palendag-1A logged gas in four stacked reservoir zones between ~3,700 mTVDSS and ~4,700 mTVDSS, which do not directly correlate to the hydrocarbon bearing zones in Dabakan. Gas samples were recovered via RDT for all four hydrocarbon bearing reservoirs, with gas properties similar to that of the Dabakan discovery. No flow tests were attempted in either discovery well.

The reservoirs encountered in the Dabakan and Palendag discoveries consist of Late Miocene deepwater turbidite sandstones, deposited in a mud-rich marine slope environment. Reservoir intervals are separated by shale layers acting as effective seals. Petrophysical interpretation indicates effective porosities typically ranging from 13% to 23%, and net-to-gross ratios vary widely depending on unit thickness and quality. Although no cores were acquired or tests carried out, MDT and RDT pressure data confirm the presence of moveable gas. Estimated mobilities suggest moderate to good reservoir quality.

Nassiping Gas Discovery – Tetragon Energy's Interest 100%

The Nassiping area in the north of Block SC-82, has attracted hydrocarbon exploration interest since the early 1960s due to the presence of Miocene carbonate formations, which have proven reservoir potential further south in the block. Well Nassiping-2 was drilled in 1984, reaching a total depth ("TD") of 3,726 metres, before being abandoned due to drilling problems and the absence of clearly identified testable intervals. In 2012, Frontier Oil Corporation re-entered the wellbore to evaluate the previously observed gas indications in the Sicalao and Callao Limestones. The well produced a mixture of formation water and hydrocarbon gas from Callao Limestone of Middle Miocene age at depths between 2856 and 3005 mMD, with flow rates averaging some 110 Mscf/d, although no stable rate was established. The Sicalao Limestone was not tested.

The Callao Limestone primarily consists of bioclastic limestones, calcarenites, and reefal facies of the late Miocene age deposited in shallow marine environments. Based on its composition and

depositional environments, this limestone is expected to exhibit moderate to fair reservoir quality, with variable porosity and permeability. Gas flowing to surface during the 2012 re-entry operation provides encouragement with respect to the presence of reservoir quality formation, with potential secondary porosity from dissolution and fracturing.

The quality of both open-hole and cased-hole logs in Well Nassiping-2 is poor, with limited vertical resolution and significant noise, which negatively impacts the reliability of log interpretation and saturation calculations. It is unclear which of the seven intervals perforated when testing Well Nassiping-2 produced gas and which produced formation water. High apparent water saturation ("Sw") values are calculated across all of the tested intervals, resulting in considerable uncertainty in net pay estimates.

Testing of Well Nassiping-2 has demonstrated the discovery of Contingent Resources, but with a wide range of gas quantities due to the uncertainty in reservoir net pay, reservoir quality, gas water contact and ambiguous test results. A new well would be required to acquire modern logs and possibly core, comprehensively test, gather fluid samples and assess the potential for development.

1.2 Contingent Resources

Contingent Resources *are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. 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 categorised in accordance with the level of* certainty associated with the estimates as 1C, 2C and 3C.

Table 1-1 and Table 1-2 present Sproule-ERCE's estimates of unrisked gross and net gas and condensate Contingent Resources respectively by discovery for offshore Blocks SC-80 and 81 and onshore Block SC-82.

Table 1-1: Unrisked Gas Contingent Resources as of 31 March 2026

Discovery	Block	Unrisked Gross Contingent Resources (Bscf)			Working Interest (%)	Unrisked Net Contingent Resources to Tetragon Energy (Bscf)		
		1C	2C	3C		1C	2C	3C
Dabakan	SC-80 and SC-81	131.2	241.0	598.8	37.5	49.2	90.3	224.6
Palendag	SC-80 and SC-81	49.6	228.6	720.1	37.5	18.6	85.7	270.0
Total	**SC-80 and SC-81**	**180.8**	**469.6**	**1,318.9**	**37.5**	**67.8**	**176.1**	**494.6**
Nassiping	SC-82	2.6	13.3	57.7	100.0	2.6	13.3	57.7
Total	**SC-82**	**2.6**	**13.3**	**57.7**	**100.0**	**2.6**	**13.3**	**57.7**
Total (Arithmetic sum)		**183.4**	**482.9**	**1,376.6**		**70.4**	**189.4**	**552.3**

Table 1-2: Unrisked Condensate Contingent Resources as of 31 March 2026

Discovery	Block	Unrisked Gross Condensate Contingent Resources (MMbbl)			Working Interest (%)	Unrisked Net Condensate Contingent Resources to Tetragon Energy (MMbbl)		
		1C	2C	3C		1C	2C	3C
Dabakan	SC-80 and SC-81	1.1	3.5	13.4	37.5	0.4	1.3	5
Palendag	SC-80 and SC-81	0.2	1.9	8.2	37.5	0.1	0.7	3.1
Total (Arithmetic sum)		**1.3**	**5.4**	**21.6**	**37.5**	**0.5**	**2.0**	**8.1**

Notes:

1. Tetragon Energy's net entitlement Contingent Resources require a full economic evaluation, which has not been carried out as part of this CPR and hence is not presented.
2. These are unrisked Contingent Resources that have not been risked for chance of development and are sub-classified as development unclarified
3. Totals are added arithmetically, which means statistically, there is a greater than 90% chance of exceeding the Total 1C and less than a 10% chance of exceeding the Total 3C. The aggregated 1C level may be a conservative estimate and the aggregated 3C level may be optimistic due to the portfolio effects of arithmetic summation.

1.3 Prospective Resources

Sproule ERCE has estimated Prospective Resources for three prospects in Block SC-80 and one in Block SC-81; the Labo and Kabuyao prospects, within Block SC-80, and the Aardvark prospect, within Block SC-81, target the fold belt zone, where multiple reservoirs develop as channel-fill turbidite deposits. These prospects are the same play type as the Dabakan and Palendag discoveries. The Halcon prospect in Block SC-80 is part of a currently untested basin floor fan play

For Block SC-82, Well Nassiping-2 identified Prospective Resources in the Sicalao Limestone, which underlies the productive Callao Limestone. No testing was carried out in the Sicalao Limestone in the

well. Consequently, Sproule ERCE has assigned Prospective Resources to the Sicalao Limestone within the Nassiping anticline.

Sproule ERCE has considered a combination structural-stratigraphic approach to estimate a range of hydrocarbon initially in place ("HIIP") and Prospective Resources for the reservoir intervals in the four prospects in Block SC-80, SC-81 and the Sicalao Limestone prospect in Block SC-82.

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. For Prospective Resources the estimates are categorised as 1U, 2U and 3U. Prospective Resources may be sub-classified as Prospects, Leads and Plays. A Prospect is a potential accumulation that is sufficiently well defined to represent a viable drilling target. A Lead is a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect. A Play is a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.*

Table 1-3 presents Sproule-ERCE's Low (1U), Best (2U) and High (3U) estimates of gross unrisked gas Prospective Resources, the geological Chance of Success ("COS") and the risked mean estimate of Prospective Resources within Blocks SC-80, -81 and SC-82.

Table 1-3: Gross Unrisked Prospective Resources as of 31 March 2026

Block	Prospect	Fluid Type	Gross Prospective Resources (Unrisked)				COS (%)	Gross PR
			1U	2U	3U	Mean		Risked Mean
SC-80	Labo	Gas (Bscf)	27.8	252.3	1586.9	587.3	27	158.6
	Kabuyao	Gas (Bscf)	16.6	132.8	752.9	284.5	30	85.4
	Halcon 5	Gas (Bscf)	188.8	2,671.6	19,930.3	7,145.8	19	1,357.7
SC-81	Aardvark	Gas (Bscf)	22.8	148.7	511.0	219.7	20	43.9
		Oil (MMstb)	5.4	30.1	101.4	44.1	20	8.8
SC-82	Sicalao	Gas (Bscf)	1.8	14.4	105.2	47.2	38	17.9
Total (Arithmetic sum)		**Gas (Bscf)**	**257.9**	**3,219.6**	**22,888.4**	**8,284.5**		
		Oil (MMstb)	**5.4**	**30.1**	**101.4**	**44.1**		

Notes

1. These Prospective Resources ("PR") are gross and have not been adjusted for Tetragon Energy's working interest of 37.5 percent in Block SC-80 and SC-81, and 100 percent in Block SC-82.

2. COS is the chance of geological success.
3. For Aardvark, Sproule ERCE has presented Prospective Resources assuming the prospect is either oil filled or gas filled. Sproule ERCE assesses the COS of finding hydrocarbons is 20% and the risk of finding either oil or gas is 50% gas: 50% oil. Hence the risk of finding Aardvark gas filled is 10% and the risk of finding Aardvark oil filled is 10%.
4. The estimated quantities of petroleum that may potentially be recovered by the application of a future development project(s) relate to undiscovered accumulations. These estimates have both a risk of discovery and a risk of development. Further exploration appraisal and evaluation is required to determine the existence of a significant quantity of potentially recoverable hydrocarbons.
5. These resources are not risked for chance of development and there is no certainty that if they are discovered they will be developed. Due to the current pre-exploration stage and associated risk factors of both Reservoir and Seal, a chance of development has not been assigned.
6. Totals are added arithmetically, which means statistically, there is a greater than 90% chance of exceeding the Total 1U and less than a 10% chance of exceeding the Total 3U. The aggregated 1U level may be a conservative estimate and the aggregated 3U level may be optimistic due to the portfolio effects of arithmetic summation.

1.4 Leads

A Lead is a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.

A total of 21 leads have been mapped by Tetragon Energy in Blocks SC-80, SC-81, and SC-82. Of these, seven leads are located in Block SC-80, nine in Block SC-81, and five in Block SC-82. These remain at an early stage of evaluation and have not been independently assessed by Sproule ERCE.

2 Introduction

2.1 Assets Summary

Sproule ERCE has prepared a Competent Person's Report ("CPR") on the Contingent Resources and Prospective Resources in licences held by Tetragon Energy Limited within a portfolio of three permits (SC-80, SC-81 and SC-82) in the Philippines. The assets are owned and operated by Tetragon Energy (Philippines) Pty Ltd, a 100% owned subsidiary of Tetragon Energy Limited, which in-turn was formerly a 100% owned subsidiary of Triangle Energy (Global) Limited. The permits were awarded on 24 September 2025 as part of the 2024 Philippine Bid Round and the 1st BARMM Conventional Energy Bid Round.

Blocks SC-80 and SC-81 offshore blocks are situated in Philippine waters of the South Sulu Sea, offshore Sandakan Basin, approximately 300-400 kilometres west of the coast of the island of Borneo. Water depths within the blocks range from 200 metres to over 3,000 metres in the eastern part of the area. The two permits are located within the Bangsamoro Autonomous Region of Muslim Mindanao (BARMM) (Figure 2-1). SC-80 contains two gas discoveries containing Contingent Resources while both SC-80 and SC-81 contain a number of undrilled prospects containing Prospective Resources and additional leads where the evaluation remains immature.

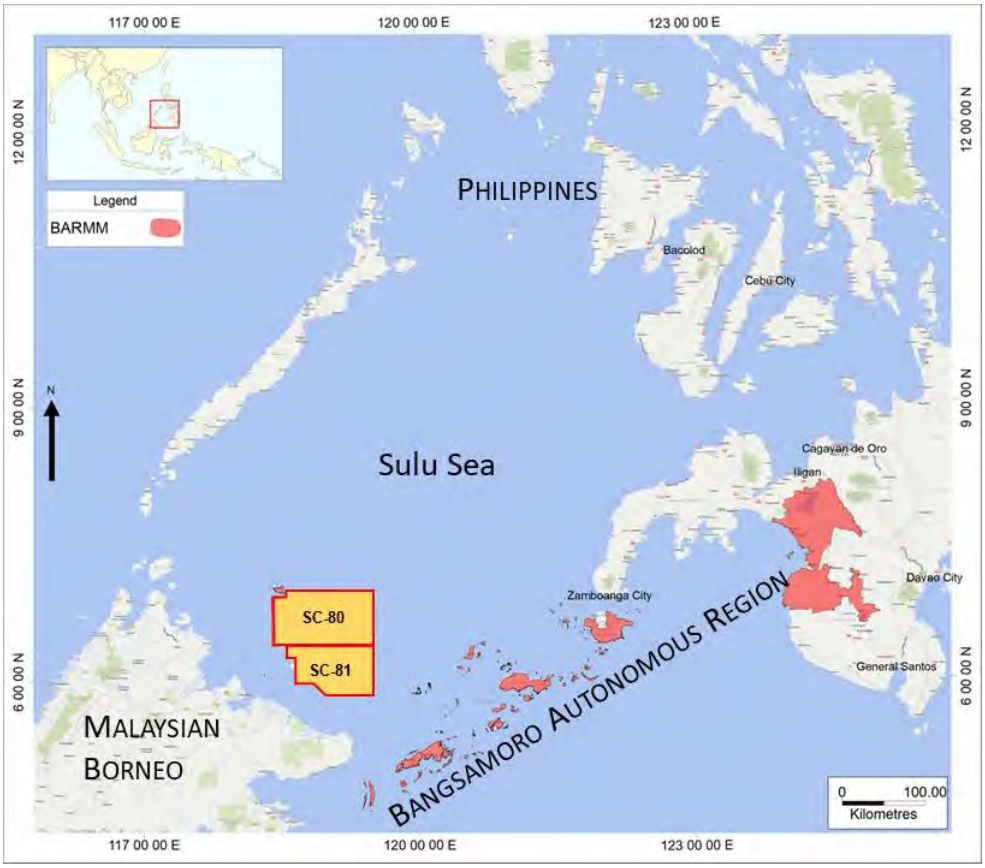

Figure 2-1: Block SC-80 and SC-81 location map

Source: Tetragon Energy

A third block, Block SC-82, is an exploration area situated onshore in the Cagayan Basin on Luzon Island, approximately 250 to 300 Kilometres NNE of Manila, at elevations ranging from approximately 45 metres to 125 metres above sea level (Figure 2-2). SC-82 contains a gas discovery with Contingent Resources and undrilled Prospective Resources.

Figure 2-2: Block SC-82 location map

Source: Tetragon Energy

Tetragon Energy (Philippines) Pty Ltd is the operator of the SC-80 and SC-81 blocks and holds a 37.5% working interest, in partnership with Sunda Energy Plc (37.5%), Philodrill Corporation (Philippines) (12.5%), and PXP Energy Corporation (Philippines) (12.5%).

Tetragon Energy (Philippines) Pty Ltd is the operator and holds a 100% working interest in Block SC-82

A summary of Tetragon Energy's licence interests, including both offshore and onshore blocks, is presented in Table 2-1.

Table 2-1: Tetragon Energy's Licence Interests

Country	Block	Area (km2)	Working Interest	Licence Expiry	Discoveries
Philippines	SC-80	7,800	37.5%	*24-Sept-2032*	Dabakan, Palendag
Philippines	SC-81	5,321	37.5%	*24-Sept-2032*	
Philippines	SC-82	4,800	100.0%	*24-Sept-2032*	Nassiping

The work programme for the offshore Block SC-80 and Block SC-81 comprises seismic re-processing, geological studies and, after four years, the drilling of two exploration wells. Tetragon Energy has the option to drop the licences at the end of the initial exploration phase, prior to committing to drilling.

The work programme for onshore Block SC-82 includes seismic re-processing, well data digitisation, geological studies, and, after seven years, the drilling of one exploration well.

2.2 Work Completed

Sproule ERCE has used standard petroleum evaluation techniques in the generation of this report. These techniques combine geophysical and geological knowledge with assessments of porosity and permeability distributions, fluid characteristics, production performance and reservoir pressure. There is uncertainty in the measurement and interpretation of basic data. Sproule ERCE has estimated the degree of this uncertainty and determined the range of petroleum initially in place. Estimates of recovery factors were prepared based on consideration of the results of well test analyses, classical reservoir engineering calculations and the performances of analogue fields. Sproule ERCE has derived independent estimates of Contingent Resources and Prospective Resources of gas and condensate.

3 Sandakan Basin, Sulu Sea: SC-80 and SC-81

3.1 Introduction

The SC-80 and SC-81 blocks, formerly known as SC56, are located within the jurisdiction of the Bangsamoro Autonomous Region in Muslim Mindanao (BARMM) in the Sulu Sea, within the Sandakan Basin, offshore the Philippines. These blocks are situated approximately 300-400 kilometres west of the coast of Borneo, in Philippine waters adjacent to Malaysia. Within the blocks, water depths range from 200 metres to over 3,000 metres in the eastern part of the area (Figure 3-1).

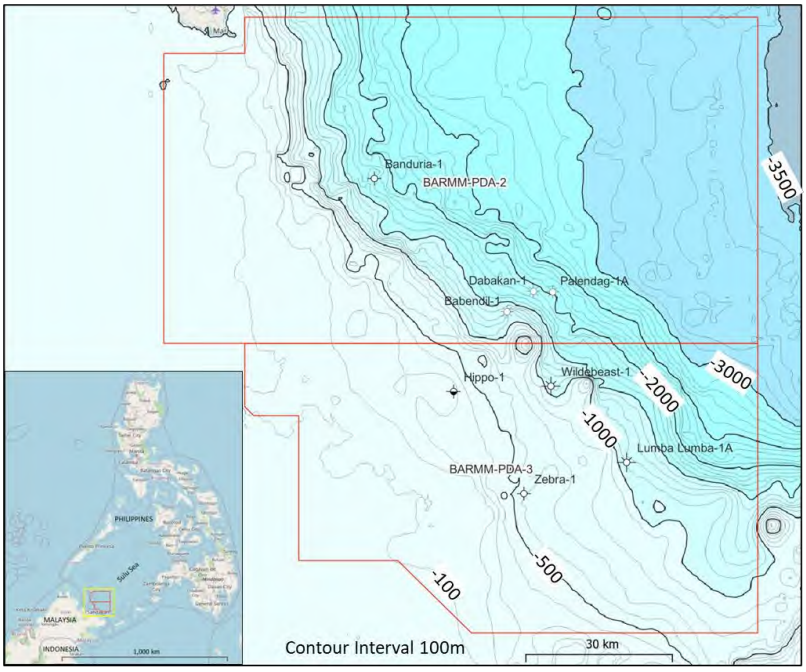

Figure 3-1: Blocks SC-80 and SC-81 water depth map

Source: Tetragon Energy

Previous operators have conducted extensive seismic exploration, including the acquisition of significant 2D seismic data and four 3D seismic surveys covering approximately 4,100 km² across the SC-80 and SC-81 areas.

Across the Sulu Sea Sandakan Basin, 31 wells were drilled between 1970 and 2010, with 16 in Philippine waters and 15 in Malaysian waters.

Several gas discoveries have been made in Block SC-80, primarily in toe thrust anticlines. Significant discoveries include Dabakan-1 and Palendag-1A. A minor discovery, Babendil-1, was made in a toe thrust anticline, discovering gas with a condensate yield of 60-80 bbl/MMscf. Dabakan and Palendag were drilled by ExxonMobil in 2009 and 2010, with the primary reservoirs consisting of a series of Miocene Turbidite sandstones.

Well Dabakan-1 penetrated a series of gas bearing sands between ~2,950 mTVDSS to 4,400 mTVDSS, including two L300 sands (designated L300 S-1 and L300 S-2) and three sands at the L100

level (L100 S-1, L100 S-2 and L100 S-3). The well was deepened beyond the L80 and L60 reservoir targets.

Well Palendag-1A encountered several correlated reservoir intervals from the Upper Miocene. Within this stratigraphic package, eight distinct seismic reflections at Palendag showed amplitude anomalies above the background: L370, L355, L200, 100, L60, L50, L40 and L20. The four deeper sands, between 4,000 mTVDSS and 4,700 mTVDSS were gas-bearing, while the shallower sands were water bearing.

Tetragon Energy serves as the operator of the permits, holding a 37.5% interest in the two blocks.

Tetragon Energy has to date focused its efforts on quality control and validating the prospectivity of the permits. Following the award, the joint venture is committed to a programme that will include seismic reprocessing and further geological studies. This programme will culminate in the drilling of up to two wells on each of the permits (Table 3-1). Tetragon Energy has the option to withdraw following the seismic re-processing at the end of SP2 (Year 4) of both blocks.

Table 3-1: Tetragon Energy: SC-80 Work programme summary

Block SC-80		
Year	Phase no/ Duration	Work Commitment
1	SP1 24 months	2,000 km2 3D PSDM seismic reprocessing + G&G studies
2		
3	SP2 24 months	Rock physics & seismic inversion + interpretation
4		Preliminary well planning
		Scoping development & economics studies
5	SP3 18 months	Plan & Drill 1 well, minimum 3,000 mTVDSS
6		
6	SP4 18 months	Plan & Drill 1 well, minimum 3,000 mTVDSS
7		

Block SC-81		
Year	Phase no/ Duration	Work Commitment
1	SP1 24 months	1,600 km^2 3D PSDM & 1,000-line km 2D seismic reprocessing + G&G studies
2		
3	SP2 24 months	Rock physics & seismic inversion + interpretation
4		Preliminary well planning
		Scoping development & economics studies
5	SP3 18 months	Plan & Drill 1 well, minimum 2,000 mTVDSS
6		
6	SP4 18 months	Plan & Drill 1 well, minimum 2,000 mTVDSS
7		

3.2 Exploration History

The Sandakan Basin comprises an area of approximately 12,000 to 15,000 km^2 and remains relatively underexplored, with 31 wells drilled (Figure 3-2). Hydrocarbons presence has been confirmed in 12 of the 16 wells drilled in the SC-80 and SC-81 areas (Table 3-2).

Exploration activities began in the 1970s, initially focusing on the shallow water areas of the Sandakan Basin offshore Malaysia. The first wells drilled in the Philippine area were Well PEC 333-1 in 1974 and Well PEC 389-1 in 1975, both operated by Philippine Sun Oil Company

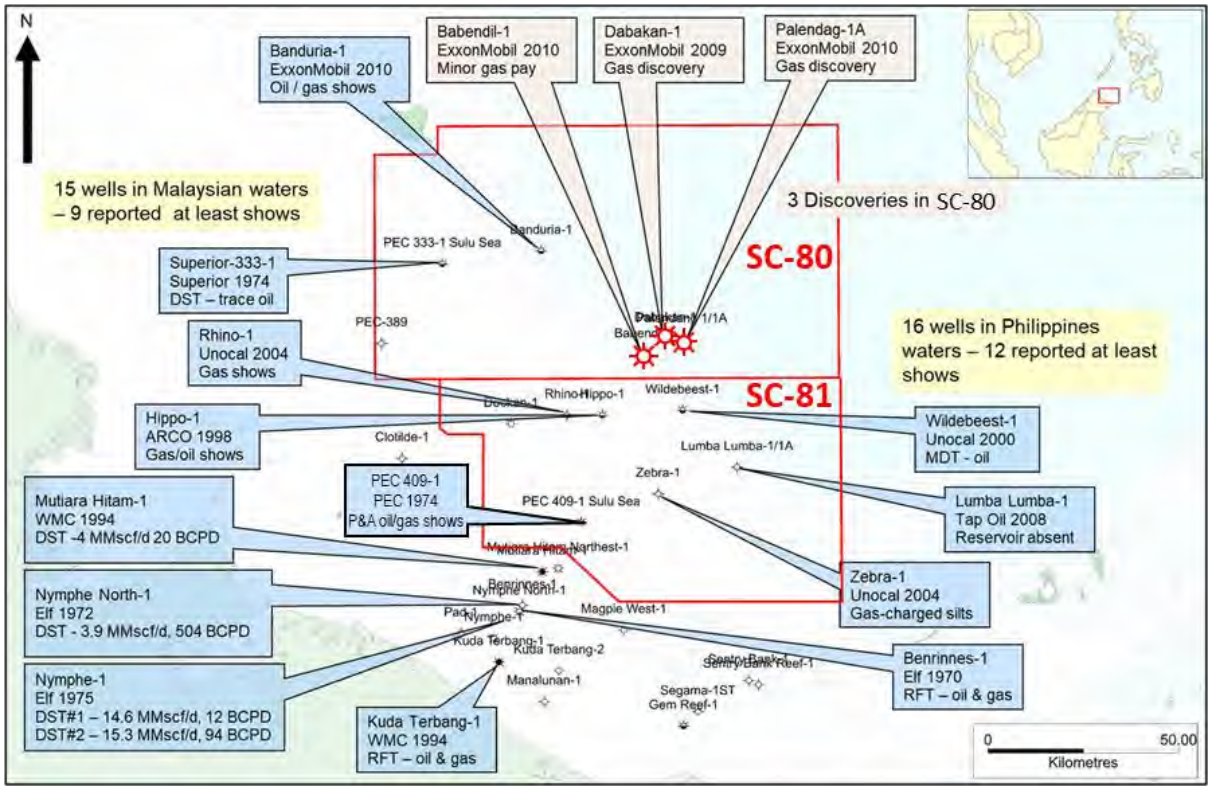

Figure 3-2: Wells drilled in SC-80 and SC-81

Source: Tetragon Energy

Well Wildebeest-1, drilled in 2000, resulted in a sub-commercial oil discovery at a depth of 1,000 metres. Subsequent drilling in deeper areas of the basin led to the discoveries of Dabakan and Palendag in 2009. Well Dabakan-1, drilled in the southeast Sulu Sea at a water depth of over 1,500 metres, was followed by Wells Rhino-1 (2004), Zebra-1 (2004), Lumba Lumba-1 (2008), Banduria-1 (2010), Palendag-1 (2010) and Babendil-1 (2010). ExxonMobil drilled all these wells in deep water, with Mitra and BHP Billiton as partners. Dabakan and Palendag were significant gas discoveries, while Babendil encountered a sub-commercial gas discovery, and Banduria resulted in a dry hole.

Well Dabakan-1 was drilled to a total depth of 4,813 mTVDSS, and gas was found at multiple levels within Miocene turbidite facies in a basal thrust anticline. The well was designed to target three stratigraphic zones of interest, which exhibited seismic amplitudes higher than the background (L100,

L200, and L300, from shallowest to deepest. Upon reaching the original planned total depth (TD), the decision was made to drill deeper into the section to evaluate the secondary targets L80 and L60.

Table 3-2: Wells drilled in SC-80 and SC-81

	WELL NAME	COUNTRY	OPERATOR	CONTENT	SPUD	WD (m)	TD (m)
SC-80	PEC 333 1	Philippines	Superior Oil	oil & gas shows	1973	107	4101
	PEC 333 1	Philippines	Superior Oil	oil & gas shows	1973	107	4101
	Dabakan 1	Philippines	ExxonMobil	gas	2009	1802	5297
	Banduria 1	Philippines	ExxonMobil	oil & gas shows	2010	1674	4370
	Palendag 1A	Philippines	ExxonMobil	gas	2010	1937	4756
	Babendil 1	Philippines	ExxonMobil	gas	2010	1272	4092
SC-81	PEC 409 1	Philippines	Superior Oil	gas shows	1974	107	4601
	Dockan 1	Philippines	The Philodrill Corp	gas shows	1989	107	2745
	Hippo 1	Philippines	Arco Philippines Inc	oil & gas shows	1998	343	3939
	Wildebeest 1	Philippines	Unocal Sulu Ltd	oil & gas shows	2000	1110	3709
	Zebra 1	Philippines	Unocal Sulu Ltd	dry	2004	564	1850
	Rhino 1	Philippines	Unocal Sulu Ltd	dry	2004	285	2460
	Lumba Lumba 1A	Philippines	Tap Oil	dry	2008	1108	2174
Out of PSC	Gem Reef 1	Malaysia	Aquitaine Petroleum	oil & gas shows	1970	45	3378
	Magpie West 1	Malaysia	Aquitaine Petroleum	dry	1970	91	1543
	Benrinnes 1	Malaysia	Aquitaine Petroleum	gas shows	1970	56	3120
	Manalunan 1	Malaysia	Aquitaine Petroleum	dry	1972	40	3402
	Nymphe North 1	Malaysia	Aquitaine Petroleum	gas & cond	1975	55	3440
	Nymphe South 1	Malaysia	Aquitaine Petroleum	gas & cond	1975	39	2957
	Nymphe 1	Malaysia	Aquitaine Petroleum	gas & cond	1975	47	2403
	Pad 1	Malaysia	Aquitaine Petroleum	dry	1975	44	1833
	Sentry Bank 1	Philippines	Superior Oil	dry	1976	22	3048
	Clotilde 1	Philippines	Amoco Sulu Sea Oil Co	dry	1982	77	2195
	Sentry Bank Reef 1A & ST	Philippines	Hartogen Energy Ltd	dry	1987	25	1779 & 1458
	Mutiara Hitam 1	Malaysia	WMC Petroleum	oil & gas	1994	77	2745
	Kuda Terbang 1	Malaysia	WMC Petroleum	oil & gas	1994	55	1590
	Mutiara Hitam NE 1	Malaysia	Petronas Carigali	gas	2005	85	3500
	Benrinnes NE 1	Malaysia	Petronas Carigali	unreported	2005	57	3120
	Segama 1 ST	Malaysia	Petronas Carigali	gas	2007	130	2321
	Kuda Terbang 2	Malaysia	Petronas Carigali	dry	2007	26	1496
	Nymphe 2ST1	Malaysia	Petronas Carigali	gas	2008	48	3208

Well Banduria-1, drilled 40 kilometres northwest to a depth of 4,339 mTVDSS, targeted a shallower reservoir in a fault-bounded anticline. Although oil and gas shows were encountered in the L300/L200 sands, all sandstones (L400, L300 and L200) were water bearing. Only traces of gas and oil shows were encountered, and the well was subsequently plugged and abandoned.

Well Palendag-1A was drilled to a total depth of 4,724 mTVDSS within a thrust propagation fold and targeted structural/stratigraphic traps at various stratigraphic levels. This well successfully discovered gas in four Late Miocene sandstone reservoirs. Well Babendil-1, which targeted Late Miocene channel sand complexes in several imbricate propagation folds, discovered limited gas play.

3.3 Data Provided

Sproule ERCE has relied upon data and information made available by Tetragon Energy. These data comprise details of 2D and 3D seismic data, basic exploration and engineering data (including well logs and core), technical reports, and interpreted data. Sproule ERCE has reviewed data made available from 2009 to the present.

- Kingdom projects in time and depth, containing full 3D seismic data, and seismic amplitude response extracted from the 3D Near and Far Stack seismic volumes.
- The depth project included horizon interpretation and polygons outlining areas of the discoveries and mapped prospects and leads.
- Well completion logs (Exxon Mobil).
- Petrophysical evaluation Palendag, Dabakan (Exxon Mobil), 2009.
- Independent Resources Assessment of Mitra Energy Limited (SGS Horizon), 2011.
- Appendix- Resources Assessment of Mitra Energy Limited (SGS Horizon), 2011.
- Independent Resources Assessment of Mitra Energy Limited (SGS Horizon), 2012.
- Independent Resources Assessments of Mitra Energy Limited (RPS Energy), December 2012.
- Independent Resources Assessments of Mitra Energy Limited (Senergy), March 2015.
- Asset Summaries for Philippines BARMM SC-80 & 81 (Tetragon Energy), 2025.

No site visit was undertaken in the preparation of this report.

3.4 Geological Overview

The Sandakan Basin, located in the Sulu Sea, lies within an area of active subduction, where complex tectonic interactions have shaped its structural and sedimentary framework. Its geological evolution has been influenced by a combination of extensional and compressional processes, playing a key role in its current configuration. During the Miocene, the basin underwent significant tectonic changes. In the Early to Middle Miocene, the region was dominated by an extensional regime, leading to the formation of normal faults, horst and graben structures, and subsidence, creating accommodation

space for significant sediment accumulation. In the Late Miocene, the tectonic regime shifted to compression, causing fault reactivation, structural inversion, and the development of fault-propagation folds. Several compressional deformation events throughout this period led to major erosional unconformities, the most significant occurring in the Middle and Late Miocene. These unconformities, caused by regional compression and faulting, facilitated the formation of structural traps while posing risks to trap integrity and preservation.

Seismic and stratigraphic analysis reveals a clear evolutionary trend within the basin. A transition in seismic facies is observed from the Middle Miocene to the Late Miocene and Pliocene. The depositional environment evolved from a high-energy fluvial-deltaic system in the Middle Miocene to a lower-energy shelf and shallow marine setting in the Pliocene. In distal areas, deep-water turbiditic systems indicate episodes of tectonic subsidence and sediment redistribution.

The combination of extensional and compressional phases has resulted in the formation of various hydrocarbon traps, including faulted anticlines and inversion structures, stratigraphic traps associated with sedimentary facies changes, and fault-propagation folds with potential hydrocarbon accumulations. However, preserving these traps remains challenging due to ongoing tectonic reactivation and active faulting, which could compromise seal integrity. The list of the plays is given below and shown schematically in Figure 3-3.

- Structural play; gravity-driven thrust foldbelt. Deepwater turbidites in Late Miocene sandstone reservoirs. Three discoveries in SC-80; Dabakan-1, Palendag-1A, Babendil-1.
- Mio-Pliocene deltaic and shelf sands in extensional structural traps. Shallow water west part of SC-81.
- Mio-Pliocene slope fan and channel sands; Stratigraphic and combination traps tested by Wildebeest-1, Lumba Lumba-1 (SC-81).
- Foredeep basin floor Late Miocene turbidite fans. Large undrilled prospects (SC-80).
- Deep Middle Miocene carbonate reef play (SC-80).
- Topogi Pliocene shallow reefs (SC-81).

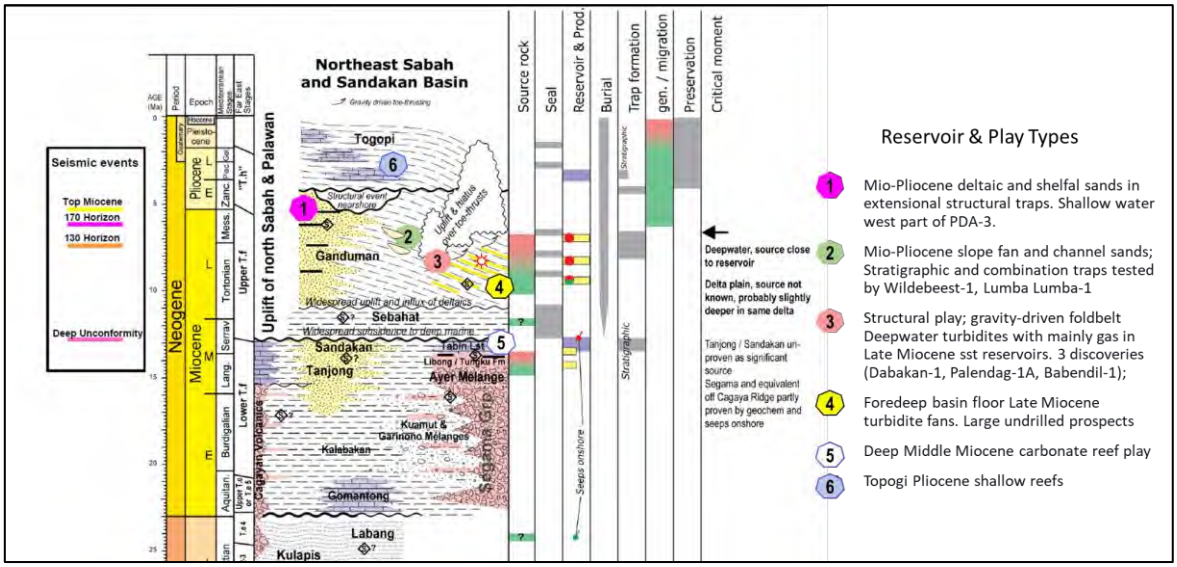

Figure 3-3: Stratigraphy, Petroleum System & Plays of the Sandakan Basin

Source: Tetragon Energy

3.5 Hydrocarbon Discoveries Dabakan and Palendag

The Dabakan and Palendag discoveries are located within the boundaries of Block SC-80 in the Sandakan Basin, approximately 150 km off the coast of Malaysia within Philippine waters. Dabakan was discovered in 2009 by Well Dabakan-1 at a water depth of 1802m. Palendag was discovered in 2010 by Well Palendag-1A at a water depth of 1,937m and sits to the east of Dabakan-1.

Well Dabakan-1 was drilled to a total depth of 4,813 mTVDSS. It encountered eight hydrocarbon pay reservoirs (all gas bearing with condensate) within Late Miocene turbidites deposited in a deepwater setting. The Dabakan discovery structure is a thrust fault-bound propagation anticlinal fold, located in the anticlinal hanging wall of an NW-SE trending toe thrust, which defines the eastern boundary.

Well Palendag-1A was drilled to a total depth of 4,724 mTVDSS. It encountered four hydrocarbon pay reservoirs (all gas bearing with condensate), all within a slightly older Late Miocene sequence than in Well Dabakan-1. The Palendag discovery has a similar structural setting to Dabakan, associated with a separate thrust fault (Figure 3-4).

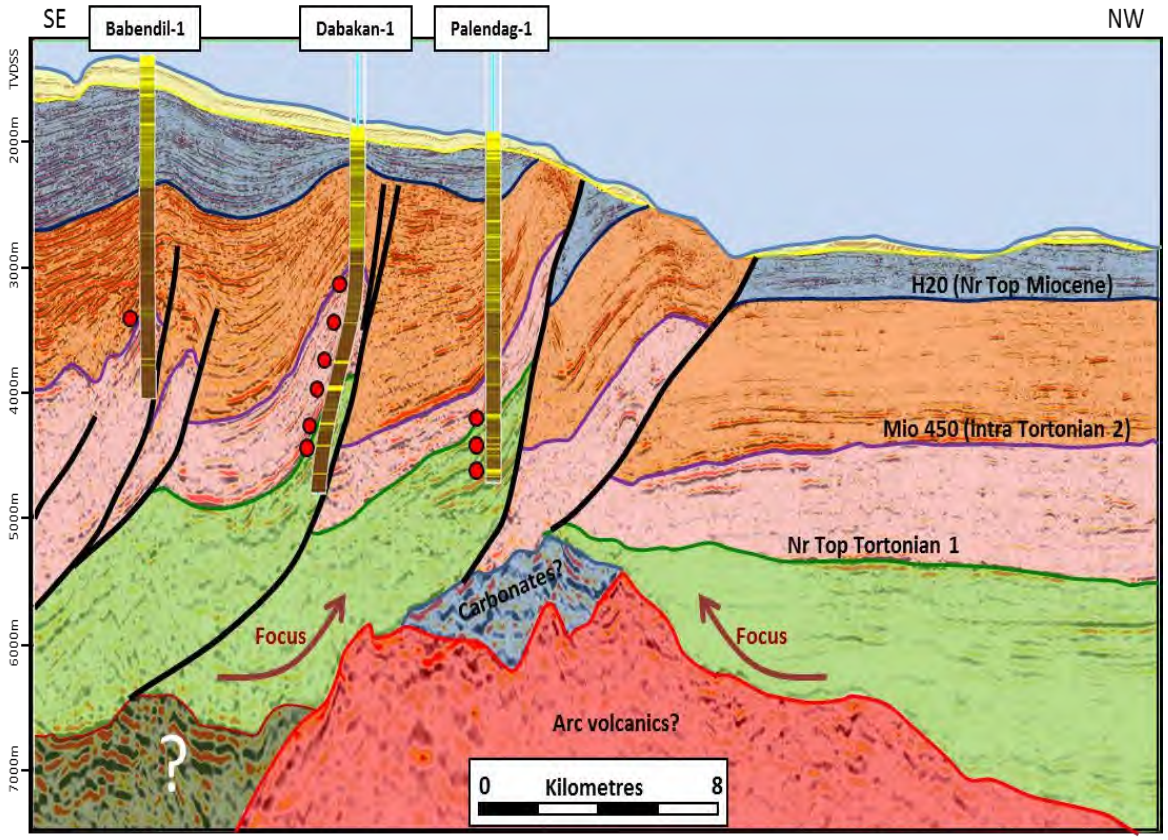

Figure 3-4: Schematic geo-seismic line through Dabakan and Palendag

Source: Tetragon Energy

3.5.1 Geophysics Overview

The Dabakan and Palendag discoveries are covered by 1,860 km^2 3D seismic surveys acquired in 2007, alongside 2006 vintage 2D data (Table 3-3). The 3D seismic data were most recently reprocessed in 2014 by CGG as a PSDM (pre-stack depth migrated) volume using controlled beam migration ("CBM"). The 3D seismic data are processed as near, mid, and far stacks alongside a far-shaped impedance cube. Seismic data is of good quality for interpretation, although it loses some quality near to the faults. The seismic coverage is shown in Figure 3-5.

Table 3-3: 2D and 3D seismic data

3D Survey	Type	Date	Operator	Area (Km2)
API9804	PSTM	1998	BHP	900
SC41 Alpine	PSTM	2007	Tap Oil Ltd	750
Mitra 3D	PSTM/PSDM	2007	Exxon	1860
Mitra 3D	PSTM/PSDM	2013	Mitra	590
2D Survey				Line (Km)
ARI94	PSTM			3500
ARI94	PSTM	2003	BHP	1900
HPH03	PSTM	2003	BHP	2000

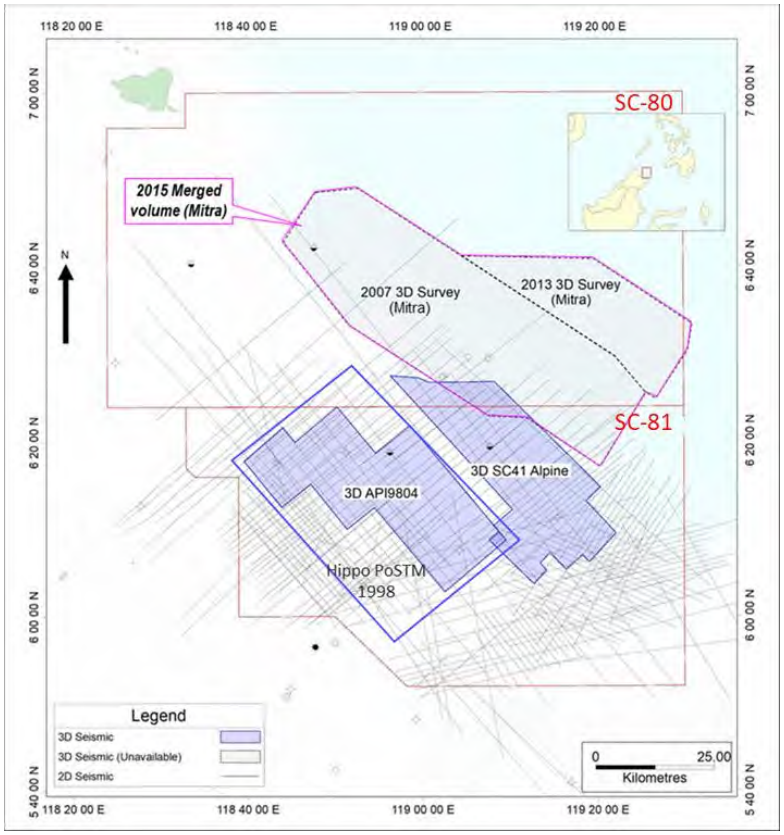

Figure 3-5: Seismic coverage over Blocks SC-80 and SC-81

Source: Tetragon Energy

3.5.2 Seismic Interpretation

The PSDM volumes provide the basis for seismic interpretation. In total, six seismic horizons are interpreted across the Dabakan discovery, and four horizons are interpreted across the Palendag discovery which are used to estimate resources. Sproule ERCE has reviewed the interpretation of these horizons in depth and finds them acceptable. Seismic lines through Wells Dabakan-1 and Palendag-1A are shown in Figure 3-6 and Figure 3-7 respectively.

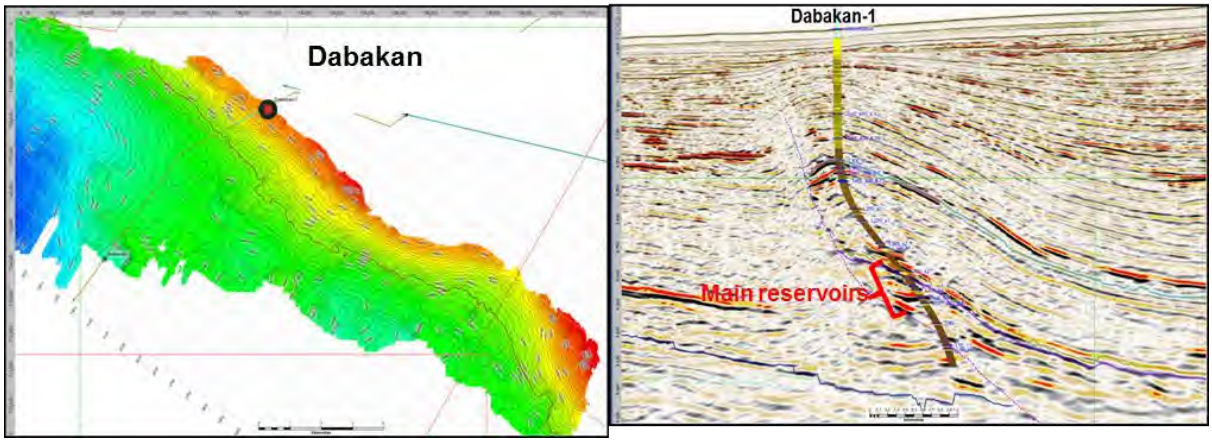

Figure 3-6: Seismic line through Well Dabakan-1

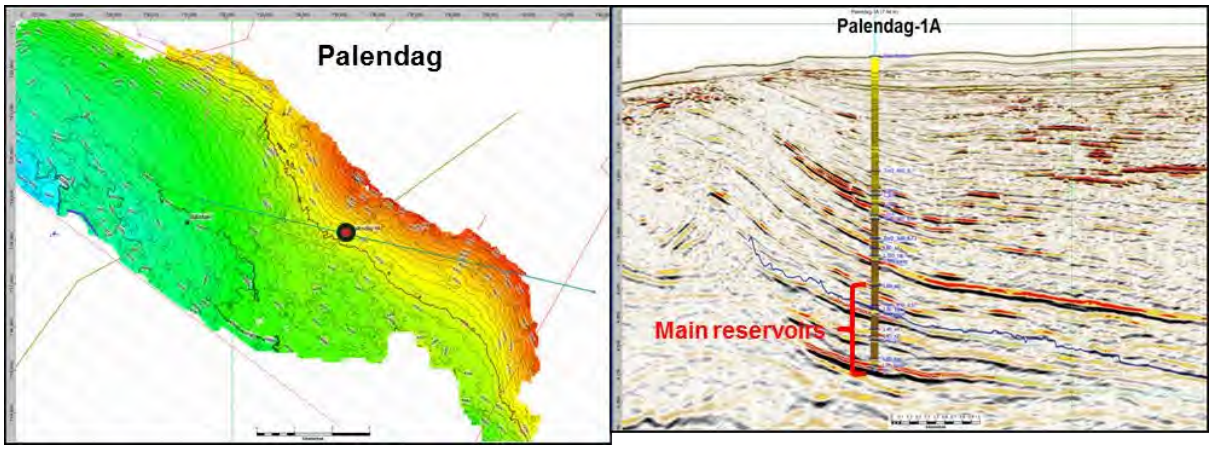

Figure 3-7: Seismic line through Well Palendag-1A

3.5.2.1 Depth Conversion

The seismic interpretation work has been conducted in the PDSM volume, and the depth conversion is based on tomography derived velocities from the PSDM processing. Some horizon interpretations appear not to be tied to the well tops, which could result from depth conversion issues or poor-quality seismic close to faults.

3.5.2.2 Rock Physics

Sproule ERCE has conducted independent rock physics work and amplitude versus offset (“AVO”) analysis on the thickest intervals, i.e. L100 S1, S2 and S3 in Well Dabakan-1 and the L50 and L20 intervals in Well Palendag-1A, to better understand reservoir and hydrocarbon distribution away from the well location. The reservoir sand is softer than the background shale.

Sproule ERCE conducted a fluid substitution modelling for these intervals by changing the fluid properties from in-situ measurements to a 100% brine to analyse the reservoir seismic response in the water leg. Sproule ERCE used the same reservoir properties reported in the fluid analysis section of Ikon’s rock physics report and applied a porosity cut-off of 8%. A well-tie analysis on Well Dabakan-1 and Well Palendag-1A shows that a simplified Ricker wavelet with a dominant frequency of 20 Hz

can be used to create a synthetic seismogram that replicates the seismic at the well location. Sproule ERCE used this wavelet to create pre-stack synthetic gathers for two scenarios of in-situ fluid (Figure 3-8) and fully brine-replaced (Figure 3-9)

Figure 3-8 is the AVO analysis for Well Dabakan-1 L100 S1 as an example. Similar to Ikon's conclusion, our results show that the amplitudes brighten with the offset up to three times. This effect can be observed at both the top and base L100 S1 reservoir. However, in the brine case, Sproule ERCE may expect a polarity reversal from nears to fars offsets and not a very bright amplitude.

Sproule ERCE also conducted a wedge modelling exercise based on the L100 S1 sand in Well Dabakan-1 to assess the effect of tuning on the amplitude (Figure 3-10). Sproule ERCE's tuning thickness is 28 metres for the near stack data and 32 metres for the far stack data. The reservoir in this case is slightly tuned but not much affected by amplitude tuning response. Sproule ERCE's results also, corroborating Ikon's conclusion, show that on the far-stack seismic, sands thicker than the tuning thickness have negligible tuning effect compared to the hydrocarbon effect. On the near offsets, however, the tuning effects are more significant.

It should be emphasized that below the tuning thickness, one can't comment on the amplitude's origin. This specifically applies to the sands in Well Palendag-1A, which are thin stacked sands.

For our assessment of HIIP, High case polygons have been drawn around areas of elevated amplitude as an indicator of reservoir quality.

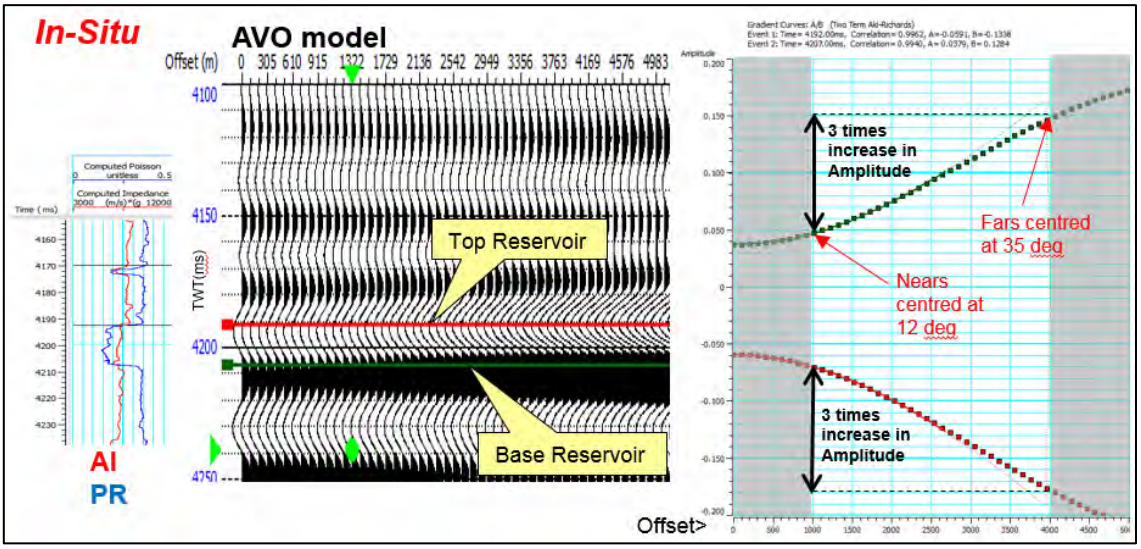

Figure 3-8: Pre-stack modelling and AVO analysis of Well Dabakan-1 at the L100 S1 sand interval using the in-situ fluid

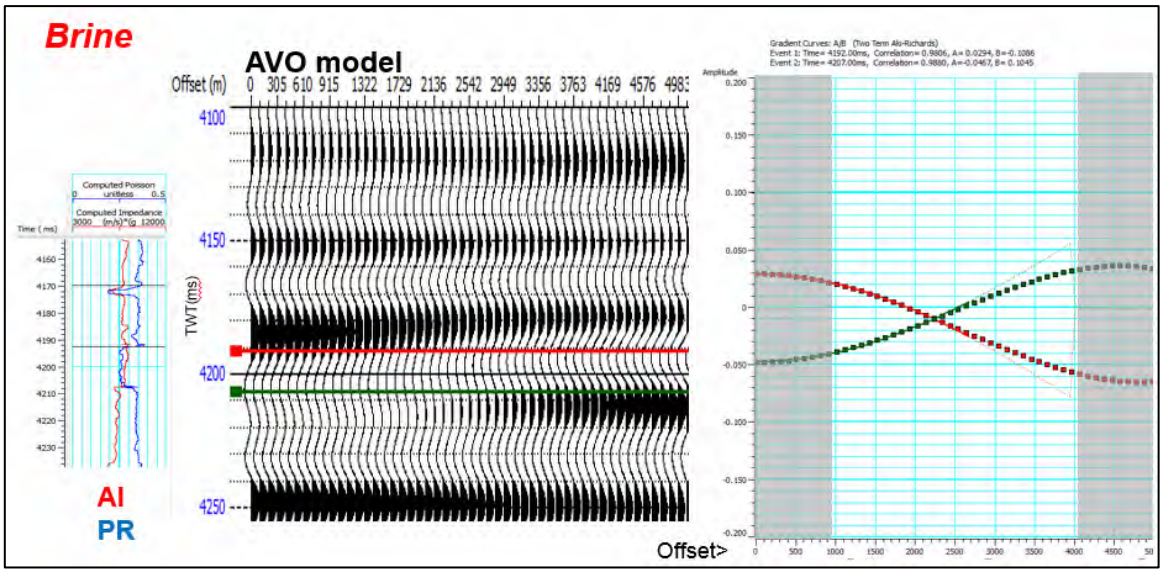

Figure 3-9: Pre-stack modelling and AVO analysis of Well Dabakan-1 at the L100 S1 sand interval using the fully substituted brine

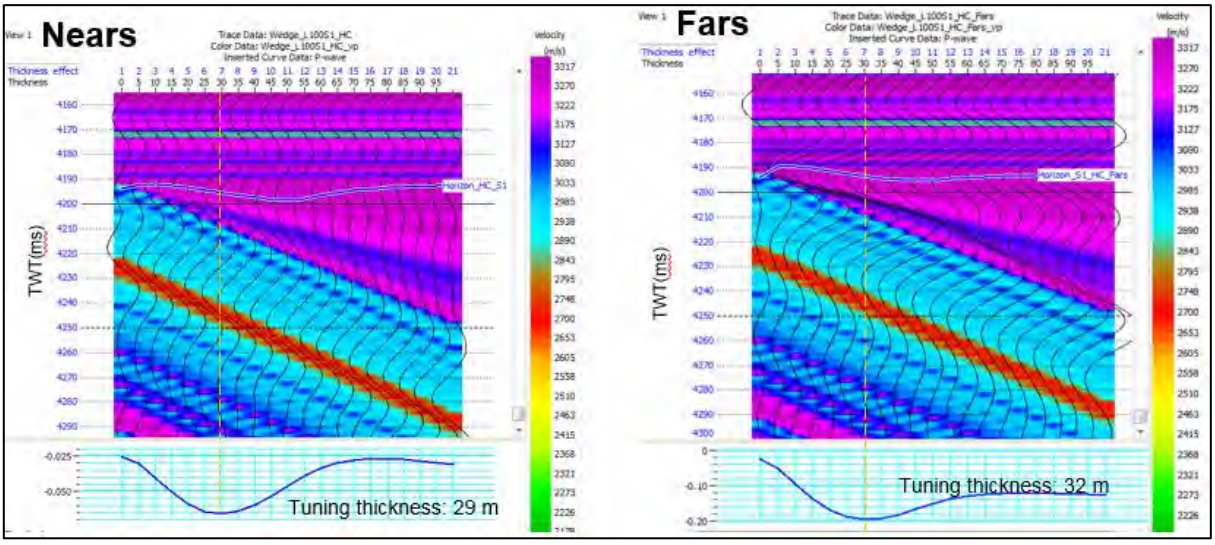

Figure 3-10: Wedge modelling using Well Dabakan-1 logs on nears (centred at 12 degrees) and fars (centred at 35 degrees)

3.5.3 Petrophysics

Well, Dabakan-1 was evaluated over the interval from 2,900 mTVDSS to a total depth of approximately 5,272 mTVDSS. Similarly, Well Palendag-1A was assessed within a comparable reservoir interval. The evaluation assumed that the interval consisted of a sand/shale sequence. Additionally, Sproule ERCE assessed Well Wildebeest-1, which is situated in Block SC-81, allowing its petrophysical parameters to be used to evaluate prospects and leads within the region. Tetragon Energy has provided the previous operator's (Exxon) petrophysical reports and interpretations.

3.5.3.1 Data available

A composite log data set was provided (Gamma Ray, Resistivity, Sonic and Density/Neutron) comprising a combination of wireline and logging while drilling ("LWD") data. Nuclear Magnetic Resonance ("NMR") data were also obtained but these data were not available for review.

3.5.3.2 Shale Volume

Shale volume was determined from the Gamma Ray, with a normal linear equation; the endpoints were based on the 2% and 98% percentiles varied for different intervals as deemed necessary. A comparison with Exxon's derived shale volume shows good agreement.

3.5.3.3 Porosity

Effective porosity was determined from the Density/Neutron crossplot with shale corrections applied. The mud filtrate density is assumed to be 0.9 g/cc as the well was drilled with an oil-based mud. A hydrocarbon correction was not applied as it was not considered necessary given the relative response of the Density/Neutron data. Good agreement can be observed between Exxon's and the Sproule ERCE computed values.

3.5.3.4 Water Saturation

Water saturation was determined using the Indonesian equation. The Archie parameters of a, m and n were taken as 1, 1.91 (based on the rotary core samples by the original well operator) and 2 respectively.

Formation water resistivity ("Rw") was determined from a Pickett plot that indicated an Rw of 0.123 ohm.m at reservoir temperature. A higher Rw of 0.176 ohm.m at bottom hole temperature ("BHT") was determined for the L60 sands that is consistent with the water sample recovered (as per the original ExxonMobil report). The shale resistivity was taken as 2 ohm.m.

Reasonable agreement can be observed between Exxon's and the Sproule ERCE computed values of water saturation ("Sw"), albeit with the previous operator Sw values being about 5% lower in the main gas bearing sands. With the information available Exxon may have used a lower Rw of 0.11 ohm.m (obtained from a wireline formation test sample and as noted in the Dabakan-1 well report) and a different equation (Modified Simandoux). Using this method and different Rw the discrepancy in Sw between Exxon and Sproule ERCE becomes negligible. As a result, and as Exxon's approach is considered to be equally valid, Sproule ERCE is content that Exxon's petrophysical interpretations are reasonable.

3.5.3.5 Sums and Averages

The same cut-offs as Exxon have been used in the petrophysical comparison. Exxon uses a set of low (Sw <=50%, VCL <=30%, PHIE>=15%), mid (Sw <=60%, VCL <=50%, PHIE>=10%), and high case (Sw <=70%, VCL <=60%, PHIE>=7%) cut-offs to define its petrophysical range. The cut-off used in the petrophysical comparison is the operator mid-case.

Given the reasonable agreement between Exxon's and Sproule ERCE's interpretation of reservoir sums and averages, Sproule ERCE finds the operator's petrophysical interpretation reasonable for Well Dabakan-1 and Well Palendag-1A.

Example computer-processed interpretations ("CPIs") for Wells Dabakan-1, Palendag-1A and Wildebeest -1 are shown in Figure 3-11 to Figure 3-13 respectively. Sproule ERCE's interpretations are shown in red and Exxon's in black for Wells Dabakan-1 and Palendag-1A.

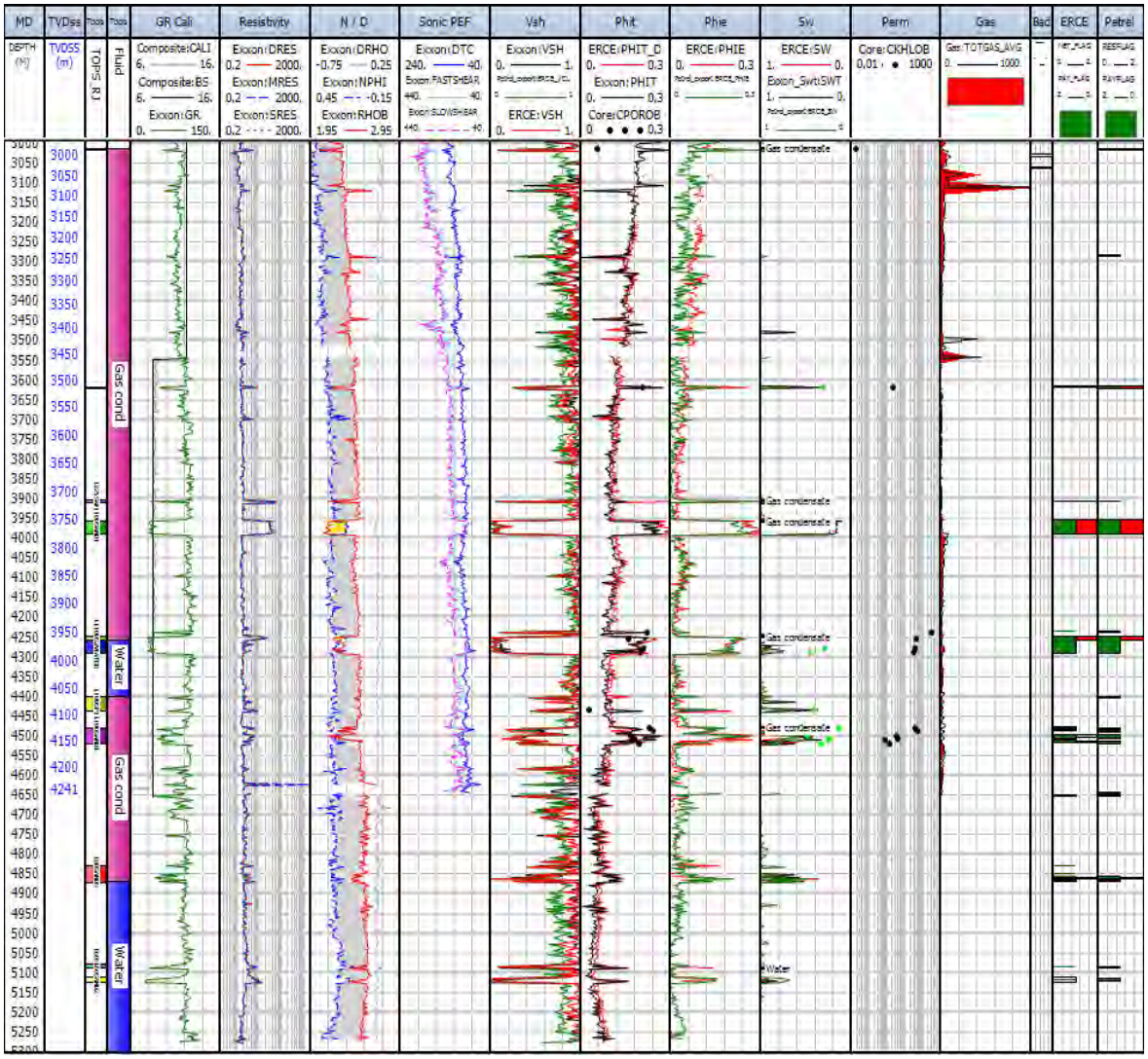

Figure 3-11: CPI for Well Dabakan-1

Sproule ERCE curve in red, Operator curves in black

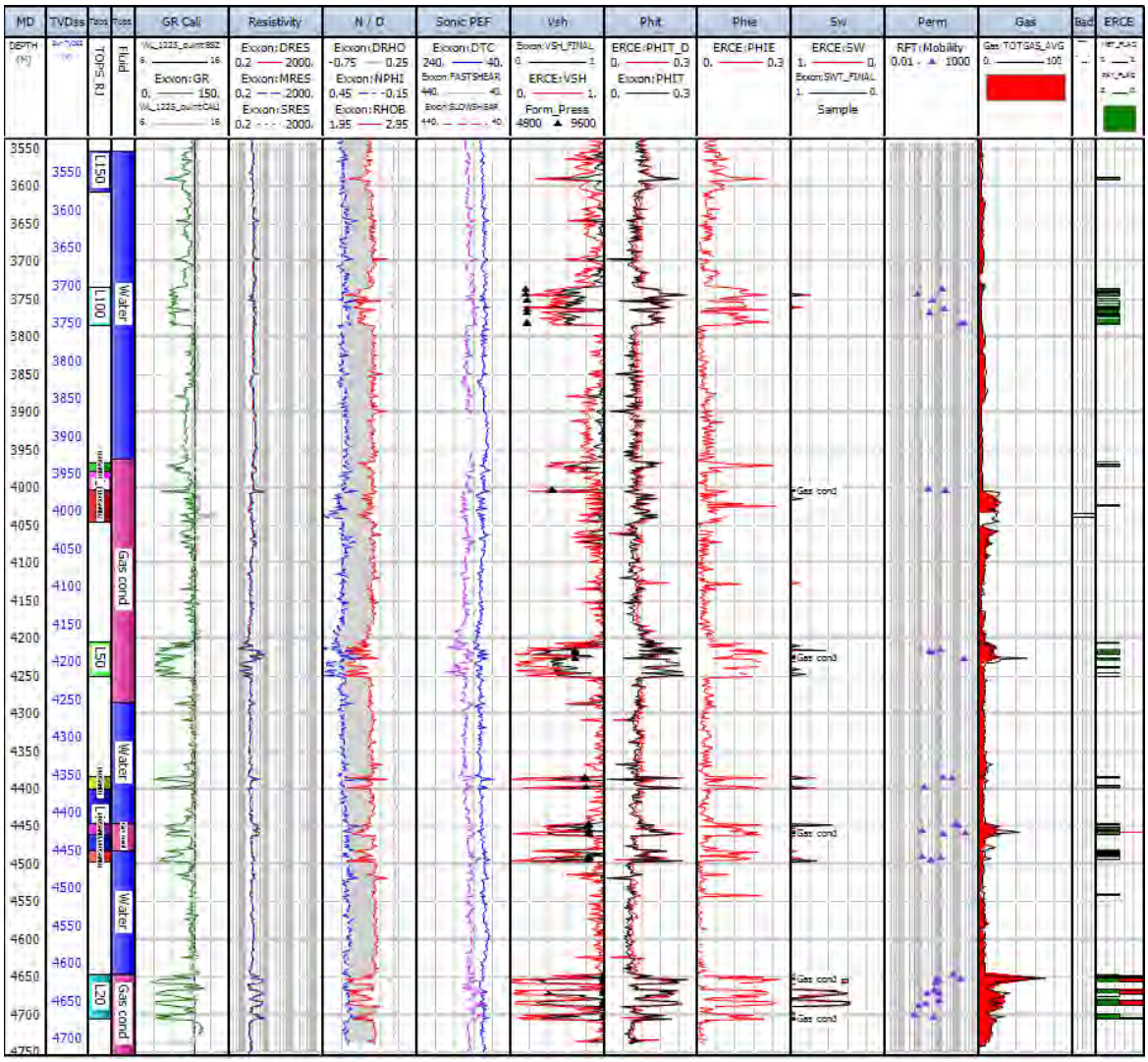

Figure 3-12: CPI for Well Palendag-1A

ERCE curve in red, Operator curves in black

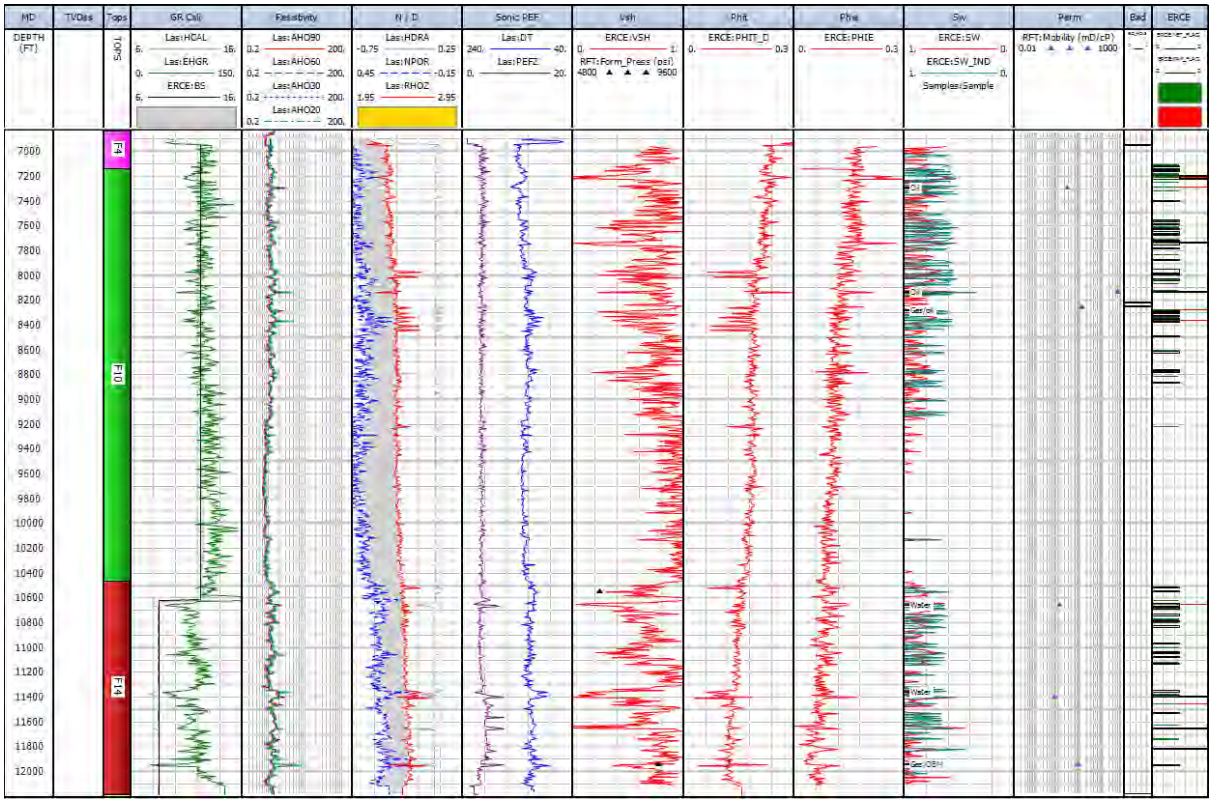

Figure 3-13: CPI for Well Wildebeest-1

3.5.4 Reservoir Engineering

3.5.4.1 Well Test and Permeability

No drill stem tests (“DSTs”) were carried out, or cores cut, in either of Wells Dabakan-1 or Palendag-1A, so there are no direct measurements of permeability of the reservoirs. Downhole samples were collected in both wells across all gas-bearing reservoirs (apart from the L225 S1 and L80 reservoirs in Well Dabakan-1), thus confirming the presence of mobile gas.

MDT pressure measurements were made in Well Dabakan -1. The L225 S1 reservoir shows a relatively poor MDT mobility (Table 3-4). The MDT mobilities measured in all other reservoirs are of good quality. The L80 reservoir has neither MDT pressures nor a sample; the presence of gas in this reservoir is inferred from log data. The reservoir quality of the L80 appears to be relatively poor from the log response. In contrast, the log character of the L100 S1 suggests that it is a good quality reservoir, and it is also the reservoir with the greatest pay.

RDT pressures were measured in Well Palendag-1A overall gas-bearing intervals. Mobilities from these points show the Palendag reservoir to be of fair quality.

Table 3-4: MDT mobility estimates for Wells Dabakan-1 and Palendag-1A

Reservoir	No. of MDT points	Mobility (mD/cP)
Dabakan		
L300 S1	none	
L225 S1	4	5
L225 S2	2	2,980
L100 S1	8	491
L100 S2	6	334
L100 S3	9	147
L80	none	
Palendag		
L100	7	41
L60 S2	2	64
L50	4	52
L40 S2	5	65
L20	13	15

3.5.4.2 Reservoir Pressures/ Fluid Contacts

In Well Dabakan-1, MDT pressure measurements were made in all gas-bearing reservoir sands, apart from the deepest L80 sands and shallowest L300 S1 sands (Figure 3-14). The only interval in which a gas-water contact ("GWC") has been identified on the wireline logs is L100 S2, and it is also the only sand in which water pressure measurements have been made. The MDT pressures show a GWC of approximately 3,964 mTVDSS in the L100 S2 sands (Figure 3-15). They are approximately 1,880 psia over pressured relative to hydrostatic pressure. All the gas-bearing sands intersected by Well Dabakan-1 are overpressured with the onset of overpressure increasing with depth. It is, therefore, not possible to define GWCs for the other sands using MDT pressures. GWCs that could be inferred by extrapolation if the aquifer pressures are the same as the L100 S2 sands are 3,850 mTVDSS for the L100 S1 sands and 3,825 mTVDSS for the L225 S2 sands.

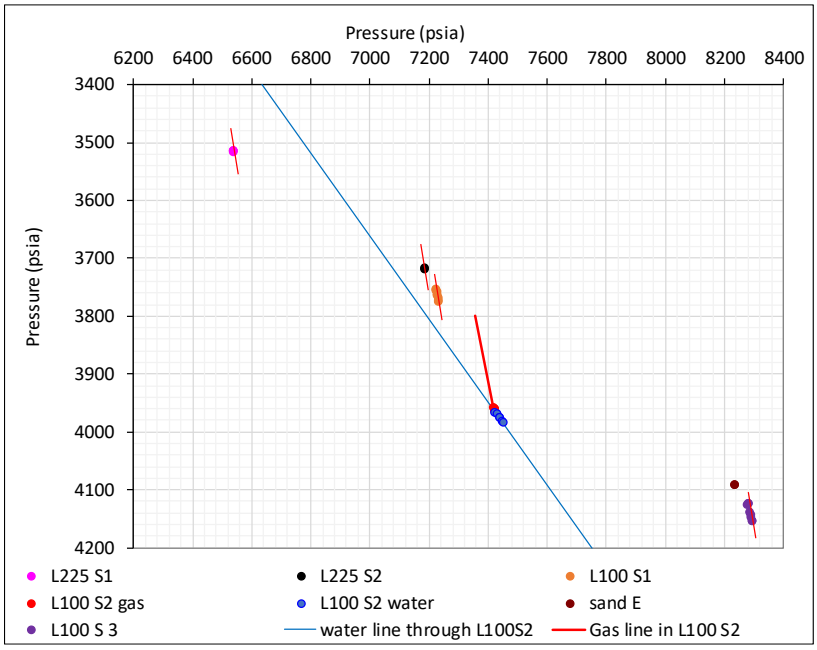

Figure 3-14: Dabakan-1 MDT pressures over all intervals

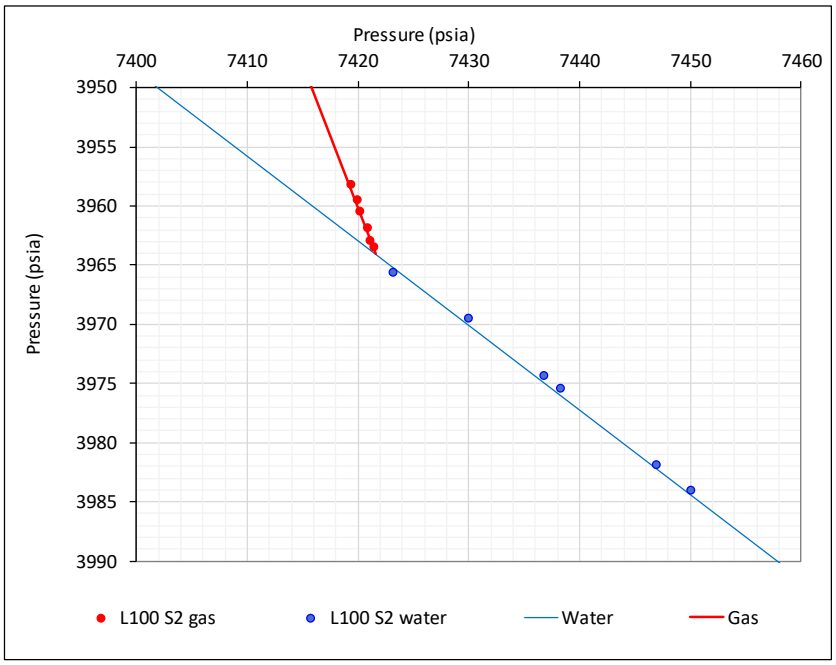

Figure 3-15: Dabakan-1 MDT pressures over L100 S2 sands

In Well Palendag- 1A, RDT pressures were taken in all the gas bearing sands, as well as the two water bearing L40S1 and L40-S3 sands above and below the gas bearing L40-S2 sands (Figure 3-16). The formations are all over pressured, with over pressure increasing with depth from approximately 200 to 300 psia at the shallowest L100 sands to nearly 3,000 psia at the deepest L20 sands. The only sands that are water bearing are the L40S1 and L40 S3 sands that lie above and below the L40 S2 sands. These sands are approximately 2,500 psia over pressured. The L40 S1 and L40 S3 sands appear to lie on the same water line. If the gas pressures in the L40 S2 sands are

extrapolated to this water line, a GWC of 4,465 mTVDSS is inferred. No GWCs for other gas bearing intervals can be inferred from the pressure measurements, due to the unknown water pressures.

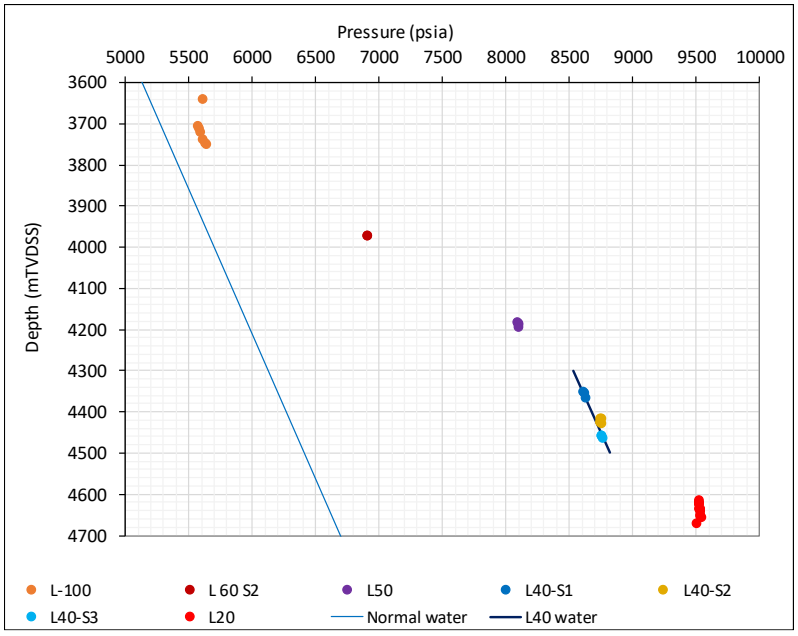

Figure 3-16: Palendag-1 RDT pressures over all intervals

3.5.4.3 Fluid Properties

Good quality downhole fluid samples were obtained from both Well Dabakan-1 and Well Palendag-1A. Sproule ERCE was provided with a report for each well[1].

A total of ten samples were analysed from Well Dabakan-1, two from each of the sands L300 S1, L225 S1, L100 S1, L100 S2 and L100 S3. The laboratory data are good quality and are comprehensive enough for making reasonable estimates of gas expansion factors ("GEF"), condensate gas ratios ("CGR") and condensate yield as a function of reservoir depletion (Table 3-5). For the L100 S2 and L80 sands, for which no PVT reports are available, Sproule ERCE used the properties from the closest formations for which data were available.

A total of nine samples were analysed from Well Palendag-1A, four from the L20, two from the L40 and L50 and one from the L60. The laboratory data are good quality and are comprehensive enough for making reasonable estimates of gas expansion factors, CGR and condensate yield as a function of reservoir depletion (Table 3-6).

[1] DQL 10026 Fluid Analysis Studies on Bottomhole Samples EMEPBV Dabakan Final Report_080811" and "DQL 10051 Fluid Analysis Studies on Bottomhole Samples EMEPBV Palendag-1A Final Report_080811

Table 3-5: Fluid properties for Dabakan

Dabakan L300 S1				
Item	Units	Low	Best	High
GEF	(scf/rcf)	307	323	340
CGR	(bbl/ MMscf)	9.8	13.1	16.3
Dry gas shrinkage		98%	98%	97%
Non-HC gas fraction		0.20%	0.20%	0.20%
Dabakan L225 S1				
Item	Units	Low	Best	High
GEF	(scf/rcf)	304	320	336
CGR	(bbl/MMscf)	17.4	23	28.9
Dry gas shrinkage		98%	97%	96%
Non-HC gas fraction		0.20%	0.20%	0.20%
Dabakan L225 S2				
Item	Units	Low	Best	High
GEF	(scf/rcf)	302	318	334
CGR	(bbl/MMscf)	20.3	27	33.8
Dry gas shrinkage		97%	96%	96%
Non-HC gas fraction		0.90%	0.90%	0.90%
Dabakan L100 S1				
Item	Units	Low	Best	High
GEF	(scf/rcf)	296	311	327
CGR	(bbl/MMscf)	22.2	29.6	37
Dry gas shrinkage		96%	95%	94%
Non-HC gas fraction		0.80%	0.80%	0.80%
Dabakan L100 S2				
Item	Units	Low	Best	High
GEF	(scf/rcf)	297	313	328
CGR	(bbl/MMscf)	20.7	27.7	34.6
Dry gas shrinkage		97%	96%	95%
Non-HC gas fraction		1.00%	1.00%	1.00%
Dabakan L100 S3				
Item	Units	Low	Best	High
GEF	(scf/rcf)	310	326	342
CGR	(bbl/MMscf)	30	40	50
Dry gas shrinkage		96%	94%	93%
Non-HC gas fraction		1.40%	1.40%	1.40%

Dabakan L80				
Item	Units	Low	Best	High
GEF	(scf/rcf)	310	326	342
CGR	(bbl/MMscf)	30	40	50
Dry gas shrinkage		96%	94%	0%
Non-HC gas fraction		1.40%	1.40%	1.40%

Table 3-6: Fluid properties for Palendag

Palendag L60				
Item	Units	Low	Best	High
GEF	(scf/rcf)	314	331	347
CGR	(bbl/MMscf)	13.7	18.2	22.8
Dry gas shrinkage		99%	98%	98%
Non-HC gas fraction		0.90%	0.90%	0.90%
Palendag L50				
Item	Units	Low	Best	High
GEF	(scf/rcf)	316	332	349
CGR	(bbl/MMscf)	6.1	8.1	10.2
Dry gas shrinkage		99%	98%	98%
Non-HC gas fraction		0.80%	0.80%	0.80%
Palendag L40				
Item	Units	Low	Best	High
GEF	(scf/rcf)	325	342	359
CGR	(bbl/MMscf)	16.2	21.6	26.9
Dry gas shrinkage		96%	95%	94%
Non-HC gas fraction		1.50%	1.50%	1.50%
Palendag L20				
Item	Units	Low	Best	High
GEF	(scf/rcf)	325	342	360
CGR	(bbl/MMscf)	22.8	30.4	38
Dry gas shrinkage		96%	95%	94%
Non-HC gas fraction		1.40%	1.40%	1.40%

Notes:

1. Dry gas shrinkage is the %age of gas recovered at surface after deduction due to fuel and flare and reduction due to recovery of condensate from the well stream.
2. Non-HC as fraction is the %age content of non-hydrocarbon gas in the well stream.

3.5.4.4 Recovery Factors

There are currently no plans for the development of the Dabakan and Palendag discoveries. Sproule ERCE has therefore applied reasonable ranges of gas recovery factors for potential future developments. For estimating gas recovery factors. Sproule ERCE has considered net pay thickness, net to gross ratio ("NTG") and qualitative assessments of reservoir permeability based on MDT and RDT pressure measurements.

Sproule ERCE has coupled the gas recovery factors to constant volume depletion ("CVD") experiment-based estimates of liquid recovery to derive ranges of recovery factors for condensate. The recovery factors that have been applied to our estimates of gas initially in place ("GIIP") to report Contingent Resources are shown in Table 3-7 for Dabakan and Table 3-8 for Palendag.

Table 3-7: Recovery Factors for Dabakan

Dabakan L300 S1			
Item	Low	Best	High
Gas	55%	65%	75%
Condensate	22%	32%	42%
Dabakan L225 S1			
Item	Low	Best	High
Gas	50%	60%	70%
Condensate	19%	29%	39%
Dabakan L225 S2			
Item	Low	Best	High
Gas	55%	65%	75%
Condensate	20%	30%	40%
Dabakan L100 S1			
Item	Low	Best	High
Gas	70%	80%	90%
Condensate	28%	38%	48%
Dabakan L100 S2			
Item	Low	Best	High
Gas	65%	75%	85%
Condensate	30%	40%	50%
Dabakan L100 S3			
Item	Low	Best	High
Gas	60%	70%	80%
Condensate	27%	37%	47%
Dabakan L80			
Item	Low	Best	High
Gas	55%	65%	75%
Condensate	24%	34%	44%

Table 3-8: Recovery Factors for Palendag

Palendag L60			
Item	Low	Best	High
Gas	55%	65%	75%
Condensate	4%	14%	24%
Palendag L50			
Item	Low	Best	High
Gas	55%	65%	75%
Condensate	9%	19%	29%
Palendag L40			
Item	Low	Best	High
Gas	55%	65%	75%
Condensate	20%	30%	40%
Palendag L20			
Item	Low	Best	High
Gas	65%	75%	85%
Condensate	24%	34%	44%

3.5.5 Hydrocarbons Initially in Place and Contingent Resources

The Dabakan and Palendag reservoirs were deposited in the Late Miocene over the L300, L225, L100, L80, L60, L50, L40, and L20 groups. They were deposited as distributary turbidites in a shelf/slope deep marine environment.

Reservoir sands have variable thicknesses (gross 4-45 m) and are separated by shales, which form effective reservoir-seal pairs. The quality of individual reservoirs is also highly variable, from as little as 10% NTG in some of the thinner units to almost 100% NTG in the well-developed, blocky L100 S Intra sand.

Given the reservoir-seal pairs, each unit is considered to have separate hydrocarbon columns.

Hydrocarbons in place have been calculated separately for each of the six gas-bearing reservoirs in Dabakan and four gas-bearing reservoirs in Palendag.

Sproule ERCE has used a combination of structural and amplitude mapping to derive a range of gross rock volumes, using polygon areas, reservoir pay thicknesses and reservoir parameters from Wells Dabakan-1 and Palendag-1A to calculate in-place volumes. In all cases, the 2C area is calculated as the lognormal between the 1C and the 3C areas.

The L100 S1 mapped amplitude has not been directly drilled and is therefore considered to be Prospective Resources, and no in-place volumes have been calculated for this unit.

Sproule ERCE has estimated low and high values for each parameter and used a log-normal distribution to obtain the values for the Mid Case. These parameters, as set out in Sections 3.5.5.1 to 3.5.5.11, have been deterministically multiplied to obtain the Low, Mid and High Case GIIP quantities. The GIIP estimates have been multiplied by the recovery factors in Table 3-7 and Table 3-8 to derive the gas Contingent Resources.

The condensate initially in place ("CIIP") estimates in Table 3-5 and Table 3-6 have been used with the recovery factors in Table 3-7 and Table 3-8 to derive the condensate Contingent Resources.

The hydrocarbons (gas and condensate) in place (GIIP and CIIP), as well as the unrisked gas and condensate Contingent Resources for each reservoir interval are summarised in Table 3-9 for Dabakan and Table 3-10 for Palendag.

Table 3-9: Dabakan Summary of GIIP, CIIP, Unrisked Gas and Condensate Contingent Resources

Reservoir	GIIP (Bscf)			CIIP (MMstb)			Unrisked Gas Contingent Resources (Bscf)			Unrisked Condensate Contingent Resource (MMstb)		
	Low	Mid	High	Low	Mid	High	1C	2C	3C	1C	2C	3C
L300 S1	1.3	10.9	60.6	0.01	0.14	0.99	0.8	7.1	42.4	0.0	1.0	41.9
L225 S1	0.1	0.6	1.9	0.00	0.01	0.05	0.0	0.4	1.3	0.0	0.0	0.1
L225 S2	0.4	3.3	25.5	0.01	0.09	0.86	0.2	2.0	17.9	0.0	0.2	15.4
L100 S1 Intra	57.3	136.9	317.5	1.27	4.05	11.75	43.0	109.5	269.9	54.7	444.0	3171.3
L100 S2	122.6	138.9	151.4	2.54	3.84	5.24	85.8	104.2	121.1	218.2	400.3	634.1
L100 S3	1.9	21.2	143.7	0.06	0.85	7.19	1.3	15.9	115.0	0.1	13.5	826.7
L80	0.0	3.0	44.7	0.00	0.12	2.24	0.0	2.0	31.3	0.0	0.2	70.1
Total	**183.6**	**314.9**	**745.3**	**3.90**	**9.11**	**28.32**	**131.2**	**241.0**	**598.8**	**1.1**	**3.5**	**13.4**

Table 3-10: Palendag Summary of GIIP, CIIP, Unrisked Gas and Condensate Contingent Resources

Reservoir	GIIP (Bscf)			CIIP (MMstb)			Unrisked Gas Contingent Resources (Bscf)			Condensate Contingent Resource (MMstb)		
	Low	Mid	High	Low	Mid	High	1C	2C	3C	1C	2C	3C
L60 S2	9.6	51.4	274.7	0.13	0.94	6.25	6.7	38.5	219.7	0.0	0.1	1.5
L50	14.3	80.0	201.3	0.09	0.65	2.05	10.0	60.0	161.0	0.0	0.1	0.6
L40 S2	4.0	18.0	103.4	0.06	0.39	2.79	2.8	13.5	82.7	0.0	0.1	1.1
L20	40.2	145.8	301.8	0.92	4.43	11.47	30.1	116.6	256.6	0.2	1.5	5.0
Total	**67.9**	**295.1**	**881.2**	**1.20**	**6.40**	**22.60**	**49.6**	**228.6**	**720.1**	**0.2**	**1.9**	**8.2**

Notes:

1. These are unrisked Contingent Resources that have not been risked for chance of development.

3.5.5.1 Dabakan L300 S1 Reservoir

The reservoir interval is shown on the CPI in Figure 3-17. The 1C polygon (dashed green) is defined by the GDT (blue line) in Well Dabakan-1 at 2,987 mTVDSS. The 3C polygon (dashed red) is defined by the closing contour at 3,300 mTVDSS to the north and by the extent of the amplitudes to the south (Figure 3-18). The input parameters are listed in Table 3-5, Table 3-7 and Table 3-11. The hydrocarbons in-place volumes and Contingent Resources are listed in Table 3-12.

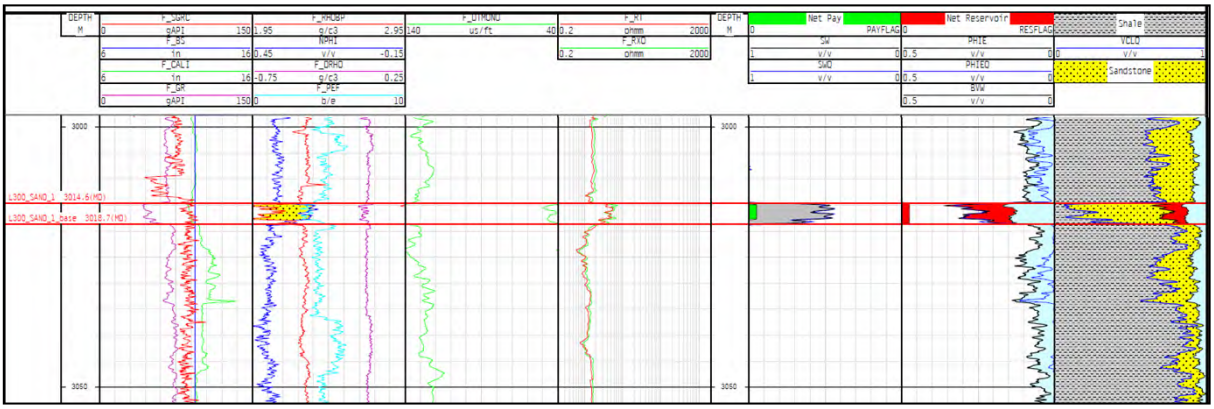

Figure 3-17: Well Dabakan-1 L300 S1 CPI

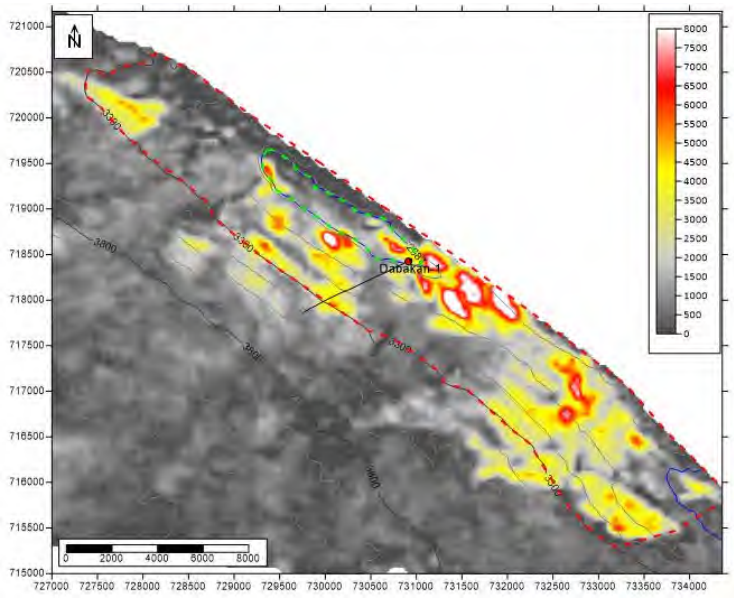

Figure 3-18: Dabakan L300 S1 amplitude extraction and volumetric polygons

Table 3-11: Input parameters for Dabakan L300 S1

	Area (km²)			Thickness(m)			Porosity (fraction)			Sw (fraction)			GEF (scf/rcf)		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
L300 S1	0.6	2.9	0.4	1.6	2.90	3.6	0.27	0.28	0.29	0.52	0.50	0.47	307	323	340

Table 3-12: Dabakan L300 S1 GIIP, Unrisked Gas Contingent Resources and CIIP

Reservoir	GIIP (Bscf)			Unrisked Gas Contingent Resources (Bscf)			CIIP (MMstb)		
	Low	Mid	High	1C	2C	3C	Low	Mid	High
L300 S1	1.3	10.9	60.6	0.8	7.1	42.4	0.01	0.14	0.99

3.5.5.2 Dabakan L225 S1 Reservoir

The reservoir interval is shown on the CPI in Figure 3-19. For this reservoir interval Sproule ERCE has adopted the operator polygons, with a minor edit to include Well Dabakan-1 within the volumetric polygons. The 1C polygon (dashed green) is defined roughly by the GDT (blue line) in Well Dabakan-1 at 3,516 mTVDSS. The saddle between the well with an amplitude bright is considered to be part of the depth conversion uncertainty. The 3C polygon (dashed red) is defined by the extent of the amplitudes (Figure 3-20). The input parameters are listed in Table 3-5, Table 3-7 and in Table 3-13. The hydrocarbons in-place and Contingent Resources are listed in Table 3-14.

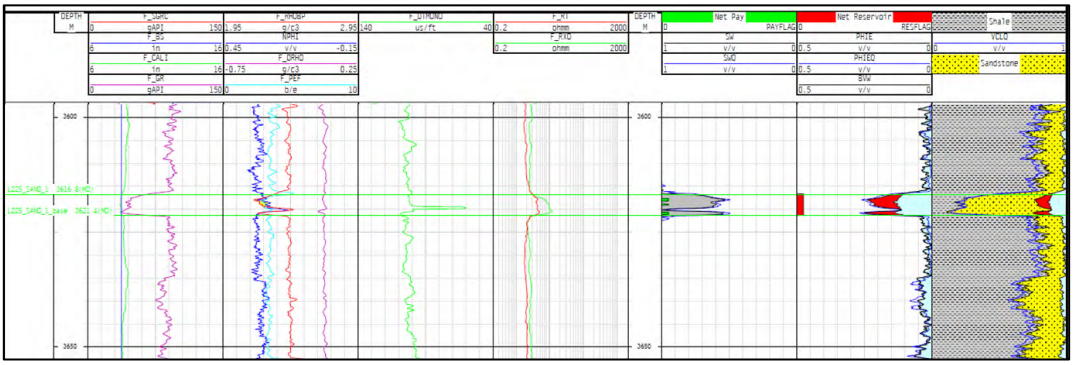

Figure 3-19: Well Dabakan-1 L225 S1 CPI

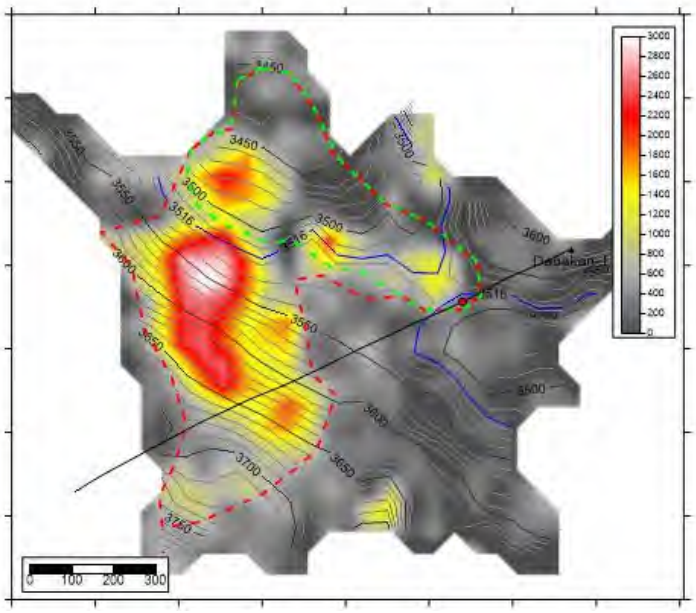

Figure 3-20: Dabakan L225 S1 amplitude extraction and volumetric polygons

Table 3-13: Input parameters for Dabakan L225 S1

	Area (km^2)			Thickness(m)			Porosity (fraction)			Sw (fraction)			GEF (scf/rcf)		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
L225 S1	0.2	0.3	0.4	0.3	1.8	2.7	0.22	0.24	0.26	0.57	0.55	0.50	304	320	336

Table 3-14: Dabakan L225 S1 GIIP, Unrisked Gas Contingent Resources and CIIP

Reservoir	GIIP (Bscf)			Unrisked Gas Contingent Resources (Bscf)			CIIP (MMstb)		
	Low	Mid	High	1C	2C	3C	Low	Mid	High
L225 S1	0.1	0.6	1.9	0.0	0.4	1.3	0.00	0.01	0.05

3.5.5.3 Dabakan L22S S2 Reservoir

The reservoir interval is shown on the CIP in Figure 3-21. There was no interpretation provided for this reservoir interval, and therefore, Sproule ERCE completed the primary analysis. To capture the uncertainty of the areal extent of this reservoir, the 1C area is the same as the 1C for L225 S1 (similar thickness sand), and the 3D area is the same as the 3C for the underlying L100 S1 intra-reservoir (approximately 35 m deeper and 25 m net pay). The input parameters are listed in Table 3-5, Table 3-7 and in Table 3-15. The hydrocarbons in-place and Contingent Resources are listed in Table 3-16.

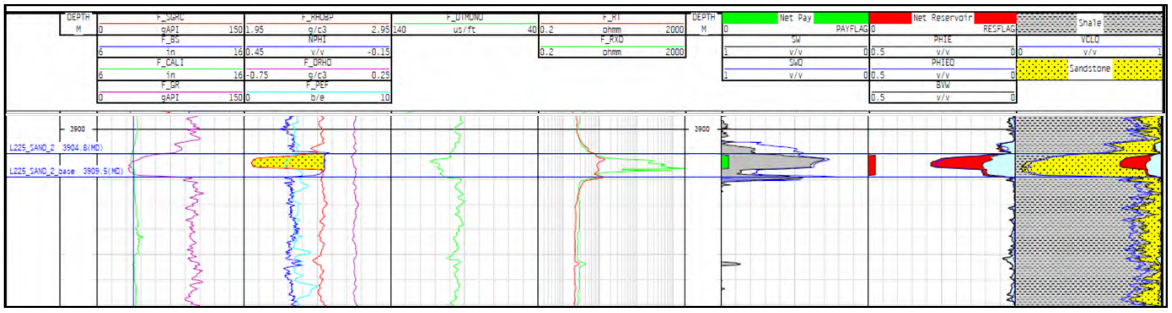

Figure 3-21: Well Dabakan-1 L225 S2 CPI

Table 3-15: Input parameters for Dabakan L225 S2

	Area (km^2)			Thickness(m)			Porosity (fraction)			Sw (fraction)			GEF (scf/rcf)		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
L225 S2	0.2	1.0	5.5	1.8	2.1	2.5	0.21	0.22	0.24	0.37	0.36	0.35	302	318	334

Table 3-16: Dabakan L225 S2 GIIP, Unrisked Gas Contingent Resources and CIIP

Reservoir	GIIP (Bscf)			Unrisked Gas Contingent Resources (Bscf)			CIIP (MMstb)		
	Low	Mid	High	1C	2C	3C	Low	Mid	High
L225 S2	0.4	3.3	25.5	0.2	2.0	17.9	0.01	0.09	0.86

3.5.5.4 Dabakan L100 Intra Reservoir

The reservoir interval is shown on the CPI in Figure 3-22. The 1C polygon (dashed green) is defined by the GDT (blue line) in Well Dabakan-1 at 3,776 mTVDSS and includes the extent of the amplitude to the southeast. The 3C polygon (dashed red) is defined by the extent of the amplitudes shown in Figure 3-23. The input parameters are listed in Table 3-5, Table 3-7 and Table 3-17. The hydrocarbons in-place volumes and Contingent Resources are listed in Table 3-18.

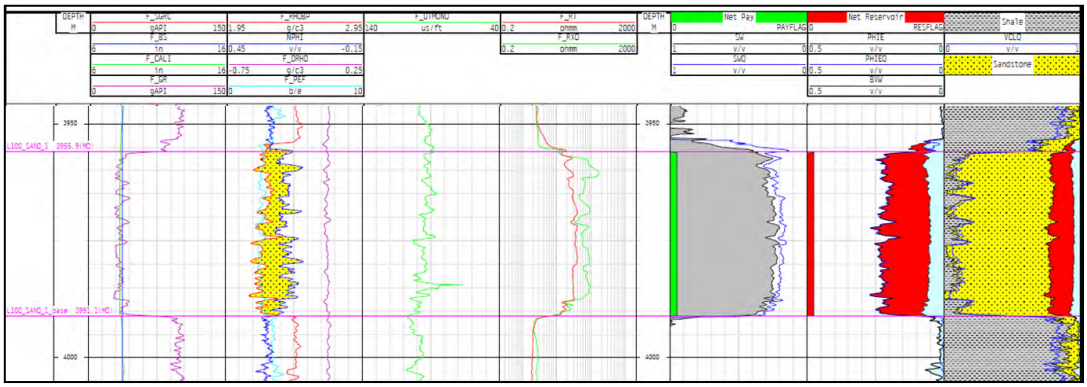

Figure 3-22: Well Dabakan-1 L100 Intra CPI

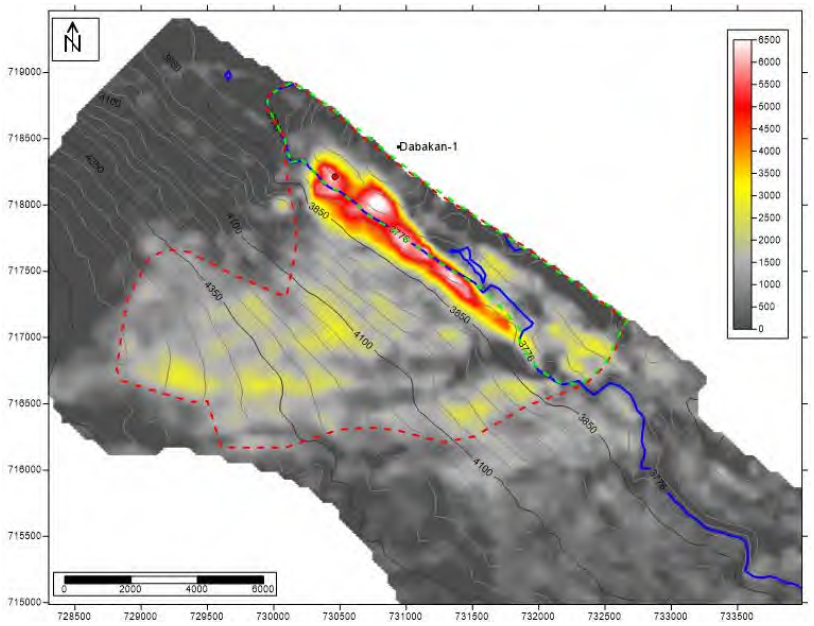

Figure 3-23: Dabakan L100 Intra amplitude extraction and volumetric polygons

Table 3-17: Input parameters for Dabakan L100 Intra

	Area (km^2)			Thickness(m)			Porosity (fraction)			Sw (fraction)			GEF (scf/rcf)		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
L100 S1	1.5	2.9	5.5	24.3	24.7	24.7	0.20	0.22	0.24	0.26	0.21	0.16	296	311	327

Table 3-18: Dabakan L100 Intra GIIP, Unrisked Gas Contingent Resources and CIIP

Reservoir	GIIP (Bscf)			Unrisked Gas Contingent Resources (Bscf)			CIIP (MMstb)		
	Low	Mid	High	1C	2C	3C	Low	Mid	High
L100 S1	57.3	136.9	317.5	43.0	109.5	269.9	1.27	4.05	11.75

3.5.5.5 Dabakan L100 S2 Reservoir

The reservoir interval is shown on the CIP in Figure 3-24, with a log-defined GWC at 3,964 mTVDSS. As the GWC is clearly defined by the logs, the 1C, 2C, and 3C polygons (Figure 3-25) are identical and are defined by the GWC closing contour against the fault. The input parameters are listed inTable 3-5, Table 3-7 and Table 3-19. The hydrocarbons in-place and Contingent Resources are listed in Table 3-20.

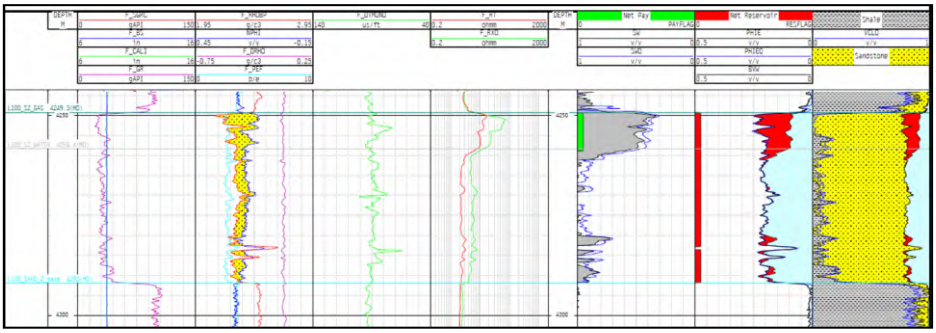

Figure 3-24: Well Dabakan-1 L100 S2 CPI

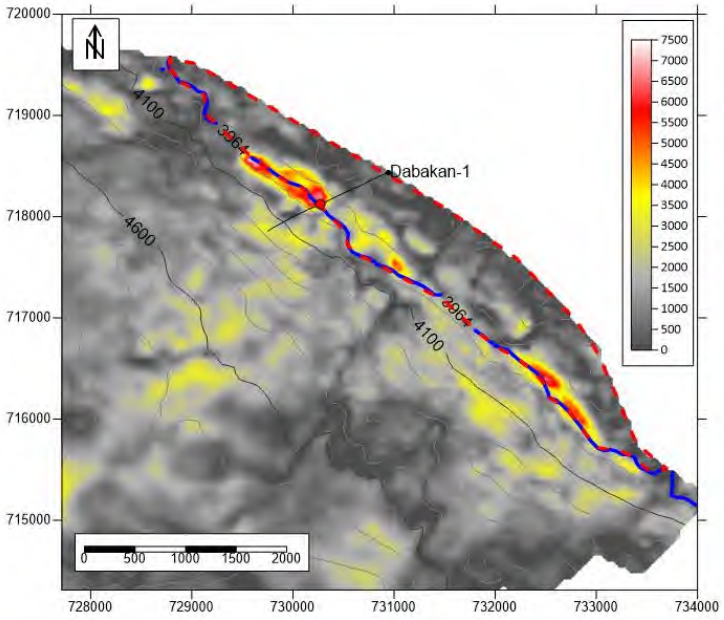

Figure 3-25: Dabakan L100 S2 amplitude extraction and volumetric polygons

Table 3-19: Input parameters for Dabakan L100 S2

	Area (km^2)			Thickness(m)			Porosity (fraction)			Sw (fraction)			GEF (scf/rcf)		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
L100 S2	3.6	3.6	3.6	28.2	29.2	29.6	0.20	0.20	0.21	0.42	0.41	0.40	297	313	328

Table 3-20: Dabakan L100 S2 GIIP, Unrisked Gas Contingent Resources and CIIP

Reservoir	GIIP (Bscf)			Unrisked Gas Contingent Resources (Bscf)			CIIP (MMstb)		
	Low	Mid	High	1C	2C	3C	Low	Mid	High
L100 S2	122.6	138.9	151.4	85.8	104.2	121.1	2.54	3.84	5.24

3.5.5.6 Dabakan L100 S3 Reservoir

The reservoir interval is shown on the CPI in Figure 3-26 . The 1C polygon (dashed green) is defined by the GDT (blue line) in Well Dabakan-1 at 4,154 mTVDSS, with a fault pinch-out to the southeast. The blue GDT contour is smoothed to the northwest where it was mis-picked. The 3C polygon (dashed red) is defined by the closing contour against the fault, as shown in Figure 3-27. The input parameters are listed in Table 3-5, Table 3-7 and Table 3-21. The hydrocarbons in-place and Contingent Resources are listed in Table 3-22.

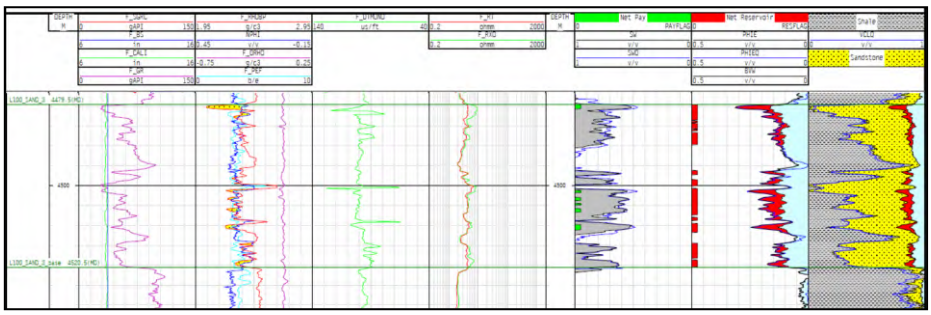

Figure 3-26: Well Dabakan-1 L100 S3 CPI

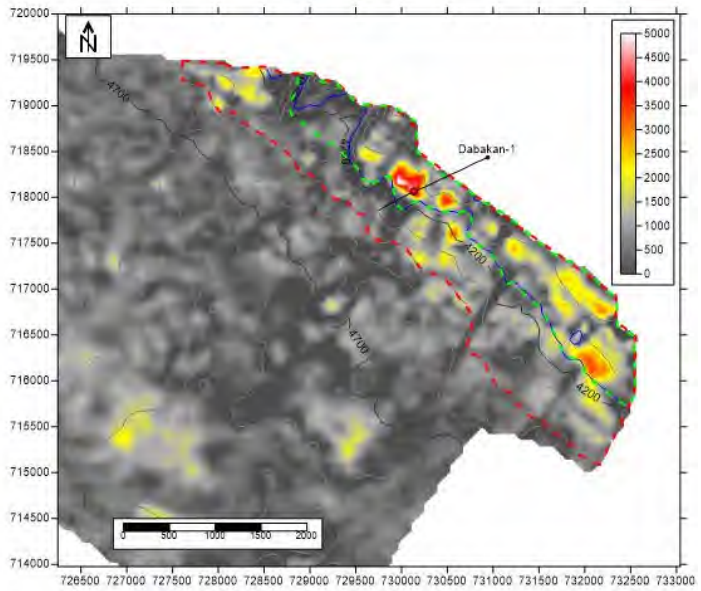

Figure 3-27: Dabakan L 100 S3 amplitude extraction and volumetric polygons

Table 3-21: Input parameters for Dabakan L100 S3

	Area (km^2)			Thickness(m)			Porosity (fraction)			Sw (fraction)			GEF (scf/rcf)		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
L100 S3	2.7	4.1	6.3	0.9	4.3	12.8	0.18	0.22	0.28	0.60	0.53	0.48	310	326	342

Table 3-22: Dabakan L100 S3 GIIP, Unrisked Gas Contingent Resources and CIIP

Reservoir	GIIP (Bscf)			Unrisked Gas Contingent Resources (Bscf)			CIIP (MMstb)		
	Low	Mid	High	1C	2C	3C	Low	Mid	High
L100 S3	1.9	21.2	143.7	1.3	15.9	115.0	0.06	0.85	7.19

3.5.5.7 Dabakan L80 Reservoir

The reservoir interval is shown on the CPI in Figure 3-28 . The 1C polygon (dashed green) is defined by the GDT (blue line) in Well Dabakan-1 at 4,428 mTVDSS with structural closure against the fault. The 3C polygon (dashed red) is the closing contour into the fault to the northwest and the extent of the amplitudes to the southeast (Figure 3-29). The input parameters are listed in Table 3-5, Table 3-7 and in Table 3-23. The hydrocarbons in-place and Contingent Resources are listed in Table 3-24.

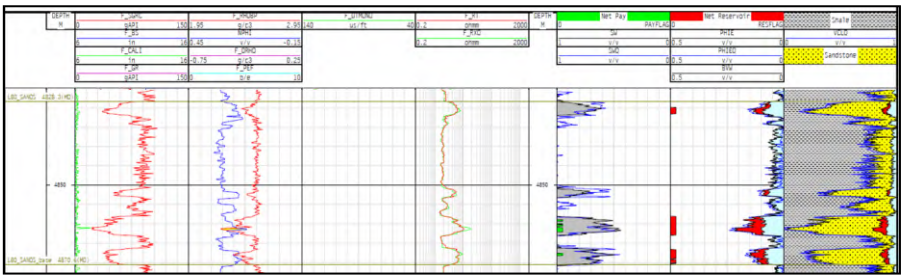

Figure 3-28: Well Dabakan-1 L80 CPI

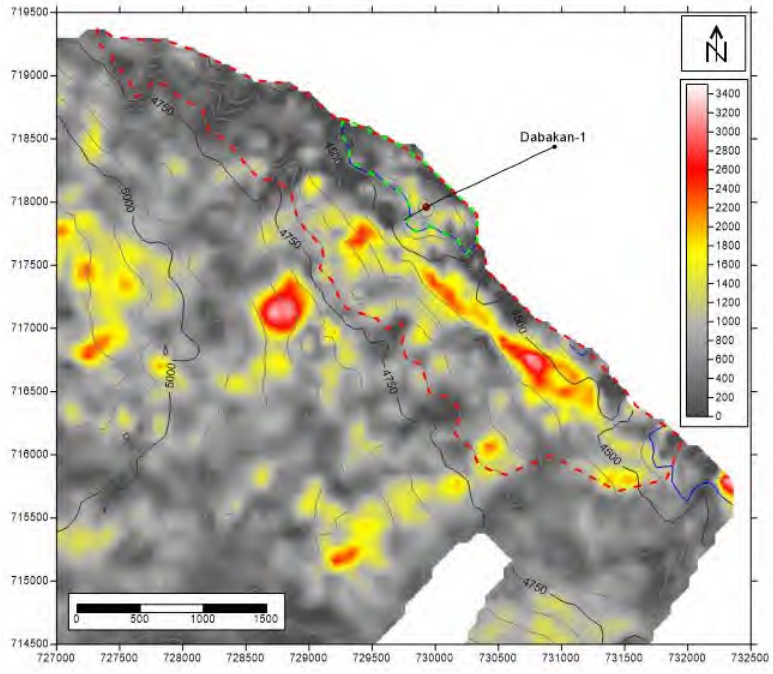

Figure 3-29: Dabakan L80 amplitude extraction and volumetric polygons

Table 3-23: Input parameters for Dabakan L80

	Area (km^2)			Thickness(m)			Porosity (fraction)			Sw (fraction)			GEF (scf/rcf)		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
L80	0.4	1.4	4.5	0.2	2.6	6.8	0.14	0.17	0.24	0.60	0.55	0.49	310	326	342

Table 3-24: Dabakan L80 GIIP, Unrisked Gas Contingent Resources and CIIP

Reservoir	GIIP (Bscf)			Unrisked Gas Contingent Resources (Bscf)			CIIP (MMstb)		
	Low	Mid	High	1C	2C	3C	Low	Mid	High
L80	0.0	3.0	44.7	0.0	2.0	31.3	0.00	0.12	2.24

3.5.5.8 Palendag L60 Reservoir

The reservoir interval is shown on the CPI in Figure 3-30. The 1C polygon (dashed green) is defined by the GDT (blue line) in Well Palendag-1A at 3,974 mTVDSS, along with amplitude extent to the southeast and extending to the northwest as far as the saddle adjacent to the fault. The 3C polygon (dashed red) has the same northwest and southeast extents as the 1C polygon but extends downdip to the 4,300 mTVDSS contour (Figure 3-31). The input parameters are listed in Table 3-6, Table 3-8 and in Table 3-25. The hydrocarbons in-place and Contingent Resources are listed in Table 3-26.

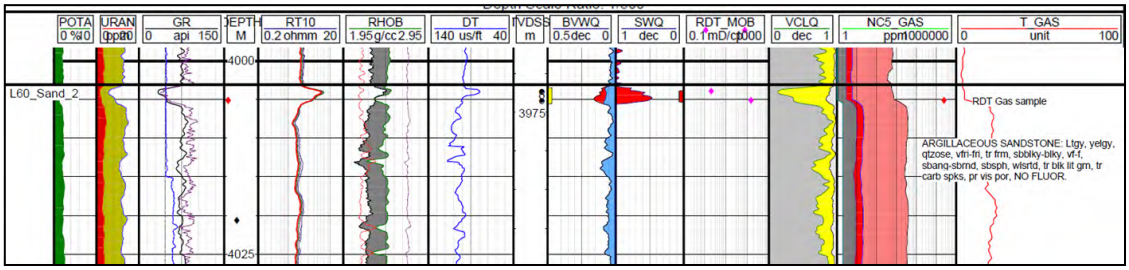

Figure 3-30: Well Palendag-1A L60 CPI

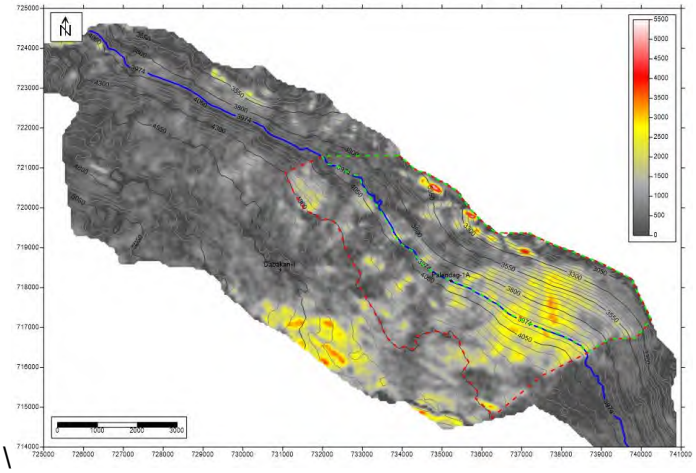

Figure 3-31: Palendag L60 amplitude extraction and volumetric polygons

Table 3-25: Input parameters for Palendag L60

	Area (km^2)			Thickness(m)			Porosity (fraction)			Sw (fraction)			GEF (scf/rcf)		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
L60	14.3	19.9	27.6	1.0	3.2	10.0	0.13	0.14	0.15	0.55	0.51	0.47	314	331	347

Table 3-26: Palendag L60 GIIP, Unrisked Gas Contingent Resources and CIIP

Reservoir	GIIP (Bscf)			Unrisked Gas Contingent Resources (Bscf)			CIIP (MMstb)		
	Low	Mid	High	1C	2C	3C	Low	Mid	High
L60	9.57	51.4	275	6.7	38.5	219.7	0.13	0.94	6.25

3.5.5.9 Palendag L50 Reservoir

The reservoir interval is shown on the CPI in Figure 3-32 . The 1C polygon (dashed green) is defined by the GDT (blue line) in Well Palendag-1A at 4,200 mTVDSS taken into the fault at the saddle contours to the northwest and southwest. The 3C polygon (dashed red) is defined downdip at the 4,350 mTVDSS contour to close to the north, and the extent of the amplitude to the southeast into the saddle (Figure 3-33). The input parameters are listed in Table 3-6, Table 3-8, and in Table 3-27. The hydrocarbons in-place and Contingent Resources are listed in Table 3-28.

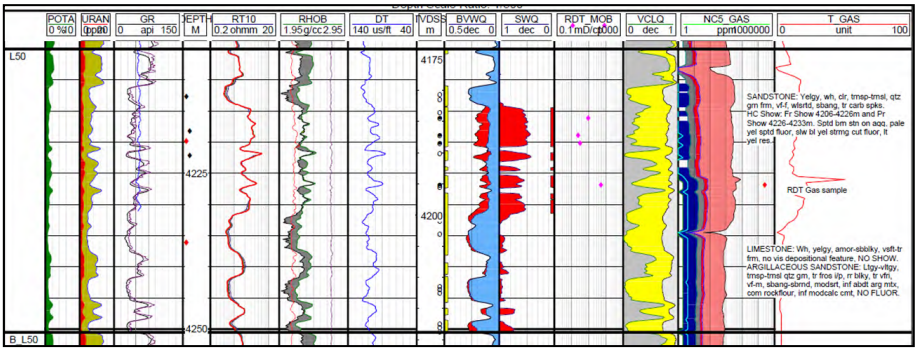

Figure 3-32: Well Palendag-1A L50 CPI

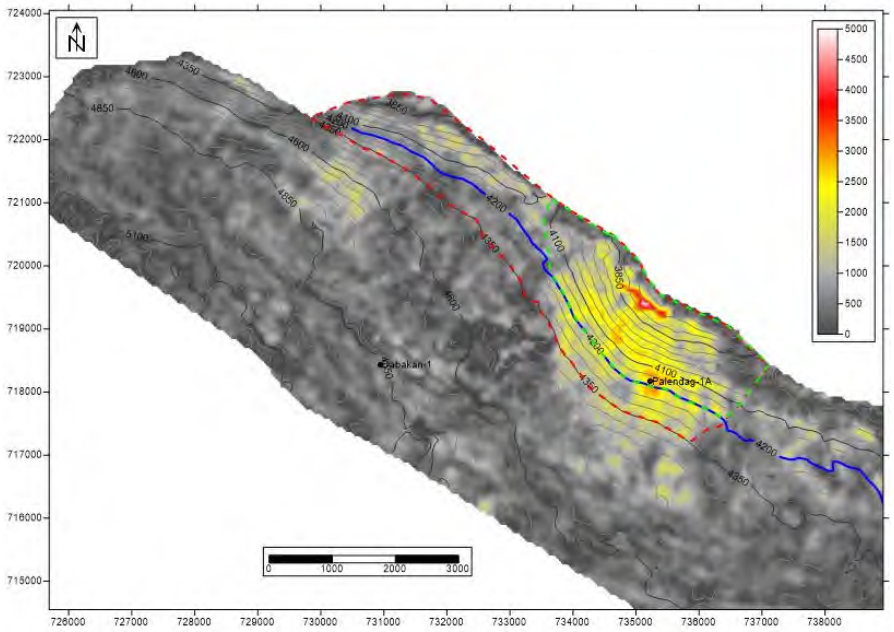

Figure 3-33: Palendag L50 amplitude extraction and volumetric polygons

Table 3-27: Input parameters for Palendag L50

	Area (km^2)			Thickness(m)			Porosity (fraction)			Sw (fraction)			GEF (scf/rcf)		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
L50	5.2	7.7	11.4	3.0	9.7	13.1	0.18	0.19	0.21	0.55	0.52	0.47	316	332	349

Table 3-28: Palendag L50 GIIP, Unrisked Gas Contingent Resources and CIIP

Reservoir	GIIP (Bscf)			Unrisked Gas Contingent Resources (Bscf)			CIIP (MMstb)		
	Low	Mid	High	1C	2C	3C	Low	Mid	High
L50	14.3	80	201	10	60	161	0.09	0.65	2.05

3.5.5.10 Palendag L40 S2 Reservoir

The reservoir interval is shown on the CPI in Figure 3-34. The 1C polygon (dashed green) is defined by the GDT (blue line) in Well Palendag-1A at 4,429 mTVDSS, taken into the fault at a saddle point to the southeast and the amplitude extent to the northwest. The 3C polygon (dashed red) is defined by the broad extent of the amplitudes, closing against the fault at the same points as the 1C polygon (Figure 3-35). The input parameters are listed in Table 3-6, Table 3-8 and Table 3-29. The hydrocarbons in-place and Contingent Resources are listed in Table 3-30.

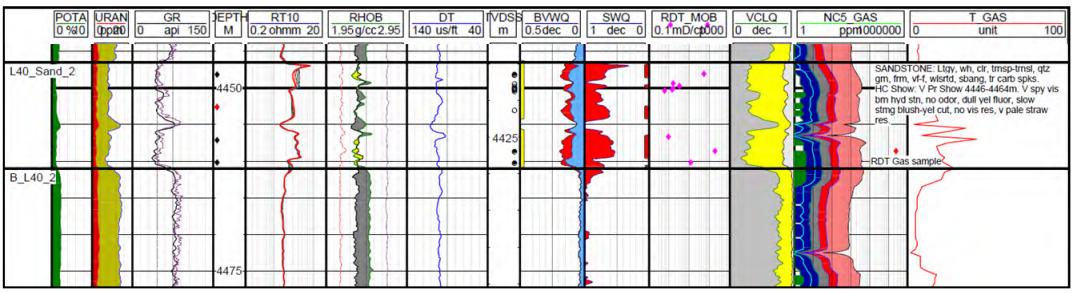

Figure 3-34: Well Palendag-1A L40 S2 CPI

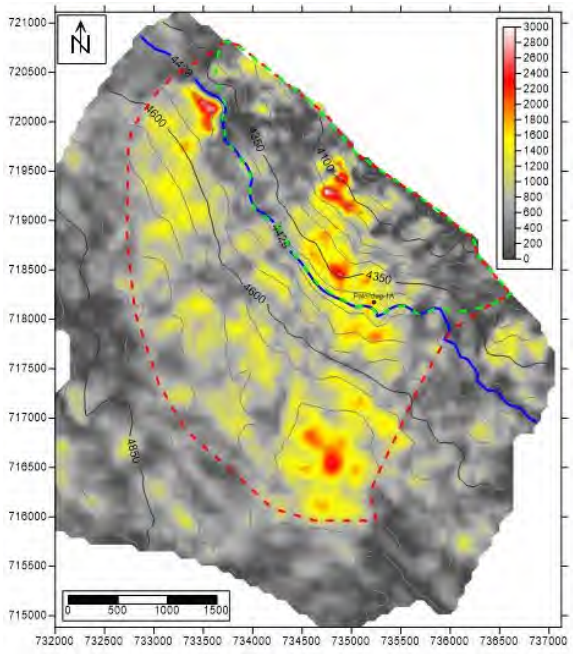

Figure 3-35: Palendag L40 S2 amplitude extraction and volumetric polygons

Table 3-29: Input parameters for Palendag L40 S2

	Area (km^2)			Thickness(m)			Porosity (fraction)			Sw (fraction)			GEF (scf/rcf)		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
L40 S2	3.6	6.4	11.5	1.5	3.0	7.6	0.16	0.17	0.18	0.61	0.54	0.48	325	342	359

Table 3-30: Palendag L40 S2 GIIP, Unrisked Gas Contingent Resources and CIIP

Reservoir	GIIP (Bscf)			Unrisked Gas Contingent Resources (Bscf)			CIIP (MMstb)		
	Low	Mid	High	1C	2C	3C	Low	Mid	High
L40 S2	3.95	17.99	103.41	2.8	13.5	82.7	0.06	0.39	2.79

3.5.5.11 Palendag L20 Reservoir

The reservoir interval is shown on the CPI in Figure 3-36. The 1C polygon (dashed green) is defined by the GDT (blue line) in Well Palendag-1A at 4,674 mTVDSS, closing against the fault. The 3C polygon (dashed red) is defined by the 4,770 mTVDSS contour and closes with amplitude shut-off to the southeast (Figure 3-37). The input parameters are listed in Table 3-6, Table 3-8 and Table 3-31. The hydrocarbons in-place volumes and Contingent Resources are listed in Table 3-32.

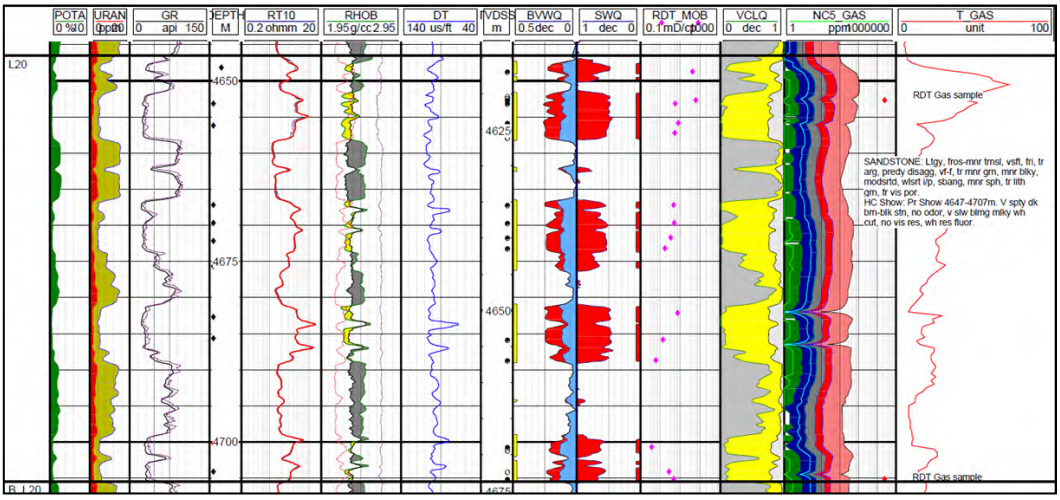

Figure 3-36: Well Palendag-1A L20 CPI

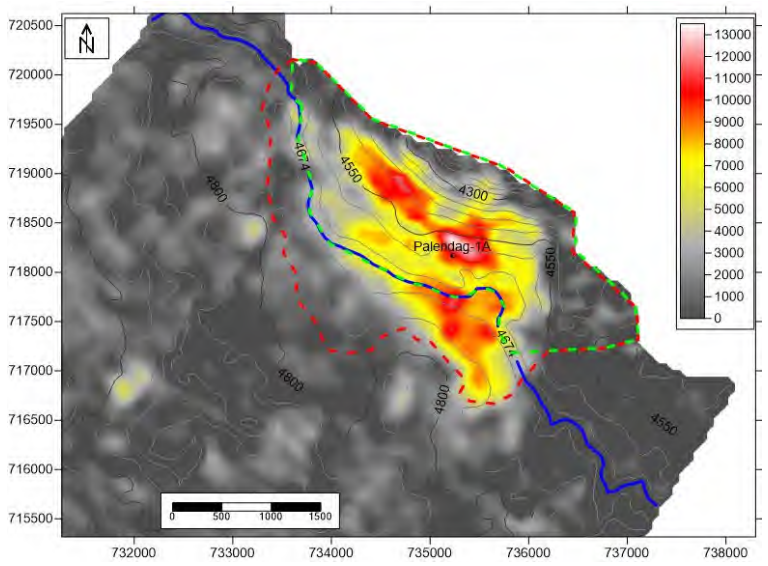

Figure 3-37: Palendag L20 amplitude extraction and volumetric polygons

Table 3-31: Input parameters for Palendag L20

	Area (km²)			Thickness(m)			Porosity (fraction)			Sw (fraction)			GEF (scf/rcf)		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
L 20	4.7	5.8	7.2	7.9	19.3	27.2	0.21	0.22	0.23	0.54	0.51	0.48	325	342	360

Table 3-32: Palendag L20 GIIP, Unrisked Gas Contingent Resources and CIIP

Reservoir	GIIP (Bscf)			Unrisked Gas Contingent Resources (Bscf)			CIIP (MMstb)		
	Low	Mid	High	1C	2C	3C	Low	Mid	High
L20	40.2	146	302	30.1	117	256.6	0.92	4.43	11.47

3.5.6 Summary of Contingent Resources

Sproule ERCE estimates of unrisked Contingent Resources for Dabakan and Palendag are shown in Table 3-33 and Table 3-34.

Table 3-33: Unrisked Gas Contingent Resources as of 31 March 2026

Field	Unrisked Gross Contingent Resources (Bscf)			Working Interest (%)	Unrisked Net Contingent Resources to Tetragon Energy (Bscf)		
	1C	2C	3C		1C	2C	3C
Dabakan	131.2	241.0	598.9	37.5	49.2	90.3	224.6
Palendag	49.6	228.6	720.1	37.5	18.6	85.7	270.0
Total	**180.8**	**479.6**	**1,318.9**	**37.5**	**67.8**	**176.1**	**494.6**

Table 3-34: Unrisked Condensate Contingent Resources as of 31 March 2026

Field	Unrisked Gross Contingent Resources (MMbbl)			Working Interest (%)	Unrisked Net Contingent Resources to Tetragon Energy (MMbbl)		
	1C	2C	3C		1C	2C	3C
Dabakan	1.1	3.5	13.4	37.5	0.4	1.3	5.0
Palendag	0.2	1.9	8.2	37.5	0.1	0.7	3.1
Total	**1.3**	**5.4**	**21.6**	**37.5**	**0.5**	**2.0**	**8.1**

Notes:

1. Tetragon Energy's working interest is based on a working interest of 37.5 percent.
2. Tetragon Energy's net entitlement Contingent Resources requires a full economic evaluation, which has not been done as part of this CPR and hence is not presented.
3. These are unrisked Contingent Resources that have not been risked for chance of development and are sub-classified as development unclarified
4. Totals are added arithmetically, which means statistically, there is a greater than 90% chance of exceeding the Total 1C and less than a 10% chance of exceeding the Total 3C

The Dabakan and Palendag Contingent Resources are sub-classified as Development Unclarified. The primary contingencies preventing classification as reserves are: the absence of production flow test data from either discovery well to confirm commercial deliverability; no established development concept or economics; and no confirmed gas market or infrastructure arrangements. Contingent Resources were estimated using a deterministic volumetric methodology based on structural and amplitude mapping of 3D seismic data and petrophysical parameters from Wells Dabakan-1 and Palendag-1A, with recovery factors from Tables 3-7 and 3-8. The work programme in Table 3-1 provides for seismic reprocessing, G&G studies and development scoping (SP1–SP2), followed by the drilling and testing of up to two wells per block (SP3–SP4), which would be required to confirm commercial deliverability and progress the resources toward development.

3.6 Prospective Resources

Sproule ERCE has evaluated four prospects in Blocks SC-80 and SC-81, each comprising multiple sub-levels, namely: Labo (Labo L-1, Labo L-2, Labo L-3), Kabuyao (Kab-100, Kab-120, Kab-160, Kab-180), Halcon (Halcon 5C), in Block SC-80 and Aardvark in Block SC-81. Prospects are defined as undrilled petroleum plays that demonstrate structural and depositional analogies to areas successfully explored by discovery wells. These are associated with potential hydrocarbon accumulations that are sufficiently well defined to represent viable drilling targets.

To support the delineation of known accumulations, Maximum and RMS amplitude anomalies were extracted from the SC56_95 Far Stack seismic datasets. These amplitude anomalies are considered indicative of sand-prone intervals and were used as a key tool in defining reservoir distribution and prospect boundaries.

Wells Palendag-1A, Dabakan-1, Babendil-1, and Banduria-1, were drilled in proximity to the identified prospects. These wells are located Southeast of the Labo and Kabuyao prospects, and Northwest of the Halcon prospect. Their primary exploration targets were stacked channel sand reservoirs, trapped

within combined structural and stratigraphic settings associated with thrust propagation folds of Middle to Upper Miocene age.

- Well Dabakan-1 recovered gas samples from four distinct reservoirs (L300 S1, L225 S1, L 225 S2, L100 Intra, L100 S2, L100 S3 and L80).
- Well Palendag-1A encountered four gas-bearing reservoir intervals (L60, L50, L40 and L20).
- Well Babendil-1 encountered gas in one sand reservoir (L100 s1).
- Well Banduria-1 encountered only traces of gas and oil.

The following sections present the input parameters used for the evaluation of each prospect, along with the results obtained for each sand unit, including the corresponding deterministic volumetric assessments.

3.6.1 Estimation of HIIP and Prospective Resources

Hydrocarbons initially in place have been calculated separately for each of the three gas prospects in Block SC-80 and for one prospect in Block SC-81 which Sproule ERCE interprets may be either gas or oil bearing.

For the Labo, Kabuyao and Halcon prospects located in Block SC-80, Sproule ERCE has used a combination of structural and amplitude mapping to estimate in-place volumes using polygon areas, reservoir pay thicknesses and reservoir parameters from Wells Dabakan-1 and Palendag-1A.

For the SC-81 Aardvark prospect, in addition to considering the reservoir parameters from Wells Dabakan-1 and Palendag-1A, the parameters from Well Wildebeest-1 were also utilised. Well Wildebeest-1 encountered oil shows (confirming the presence of paraffinic crude oils, low in sulfur and with light to medium gravity of 38.8–41.8° API) and many inboard wells also encountered oil and gas shows. Due to this phase risk both gas and oil volumetric scenarios have been calculated. The assessment includes both oil and gas prospectivity due to the geological characteristics and data indicating the presence of both hydrocarbon types in the region. Consequently, separate COS estimates were assigned to each phase, reflecting the distinct uncertainties and probabilities of success associated with each hydrocarbon type.

Sproule ERCE has estimated Low, Mid and High values for each GIIP input parameter as discussed in Sections 3.6.2.1 to 3.6.2.3 and 3.6.3.1. These parameters have been deterministically multiplied to obtain Low, Mid and High Case estimates of GIIP and stock tank oil initially in place (“STOIIP”). The GIIP estimates for the Block SC-80 prospects have been multiplied by the recovery factors in Table 3-7 and Table 3-8 to derive the gas Prospective Resources. The GIIP and STOIIP estimates for Aardvark in Block 81 have been multiplied probabilistically by the recovery factors in Table 3-46 to derive the gas or oil Prospective Resources The COS is discussed in Section 3.6.4

The GIIP and the unrisked gas Prospective Resources for each reservoir interval are summarised in Table 3-35 for the Block SC-80 prospects and in Table 3-36 and Table 3-37 for the Aardvark prospect in Block SC-81.

Table 3-35: Summary of SC-80 prospects, GIIP and Unrisked Gas Prospective Resources

SC-80		GIIP (Bscf)			Gross Unrisked Prospective Resources (Bscf)				COS (%)	PR
Prospect	Interval	Low	Mid	High	1U	2U	3U	Mean		Risked Mean
Labo	L 1	21.0	135.7	610.5	10.5	88.4	519.0	194.8	27	*52.6*
	L 2	16.7	109.7	497.2	8.3	71.5	422.7	157.5	27	*42.5*
	L 3	18.0	141.6	761.5	9.0	92.3	647.3	235.1	27	*63.5*
Total Labo		*55.6*	*387.0*	*1,869.3*	*27.8*	*252.3*	*1,588.9*	*587.3*	*27*	*158.6*
Kabuyao	L 100	6.6	39.4	171.9	3.3	25.7	146.2	55.9	30	*16.8*
	L 120	2.3	13.7	62.5	1.2	8.9	53.1	19.4	30	*5.8*
	L 160	11.2	70.2	302.2	5.6	45.7	256.9	97.1	30	*29.1*
	L 180	13.1	80.4	349.1	6.6	52.4	296.7	112.2	30	*33.7*
Total Kabuyao		*33.2*	*203.7*	*885.8*	*16.6*	*132.8*	*752.9*	*284.5*	*30*	*85.4*
Halcon	5 C	314.7	3,816.5	23,447.4	188.8	2,671.6	19,930.3	7,145.8	19	*1,357.7*
Total Halcon		*314.7*	*3,816.5*	*23,447.4*	*188.8*	*2,671.6*	*19,930.3*	*7,145.8*	*19*	*1,357.7*
Total		**403.6**	**4,407.2**	**26,202.5**	**233.2**	**3,056.6**	**22,272.1**	**8,017.6**		

Notes:

1. These Prospective Resources ("PR")vare gross and have not been adjusted for Tetragon Energy's working interest of 37.5 percent.
2. COS is the chance of geological success.
3. These resources are not risked for chance of development and there is no certainty that if they are discovered they will be developed.
4. Totals are added arithmetically, which means statistically, there is a greater than 90% chance of exceeding the Total 1U and less than a 10% chance of exceeding the Total 3U. The aggregated 1U level may be a conservative estimate and the aggregated 3C level may be optimistic due to the portfolio effects of arithmetic summation.

Table 3-36: Summary of SC-81 prospects, GIIP and Unrisked Gas Prospective Resources

SC-81	GIIP (Bscf)			Gross Unrisked Prospective Resources (Bscf)				COS (%)	Pros. Res.
	Low	Mid	High	1U	2U	3U	Mean		Risked Mean
Aardvark	38.0	214.6	638.8	22.8	148.7	511	219.7	20	43.9

Table 3-37: Summary of SC-81 prospects STOIIP and Unrisked Oil Prospective Resources

SC-81	STOIIP (MMstb)			Gross Unrisked Prospective Resources (MMstb)				COS (%)	Pros. Res.
	Low	Mid	High	1U	2U	3U	Mean		Risked Mean
Aardvark	26.9	106.5	253.6	5.4	30.1	101.4	44.1	20	8.8

Notes:

1. These Prospective Resources are gross and have not been adjusted for Tetragon Energy's working interest of 37.5 percent.
2. Sproule ERCE has presented Prospective Resources assuming the Aardvark prospect is either oil filled or gas filled. Sproule ERCE assesses the COS of finding hydrocarbons is 20% and the risk of finding either oil or gas is 50% gas: 50% oil. Hence the risk of finding Aardvark gas filled is 10% and the risk of finding Aardvark oil filled is 10%.

3.6.2 Block SC-80 Prospective Resources

During the Middle and Late Miocene, the Sandakan Basin was affected by several compressive deformation events. These fault structures, aligned in NE-SW directions, have influenced the distribution of channels. Deep water turbiditic channel systems and basin floor fans are key depositional features in the basin.

Sproule ERCE has estimated Prospective Resources for three prospects in Block SC-80 (Figure 3-38), Labo, Kabuyao and Halcon.

Labo and Kabuyao prospects are in the fold belt zone, where multiple reservoirs develop as channels and comprise the same play type as the Dabakan and Palendag discoveries.

The Halcon prospect is part of a basin floor fan play. Sproule ERCE has considered a combination structural-stratigraphic approach to estimate a range of hydrocarbons initially in place (HIIP) for the reservoir intervals in these three prospects.

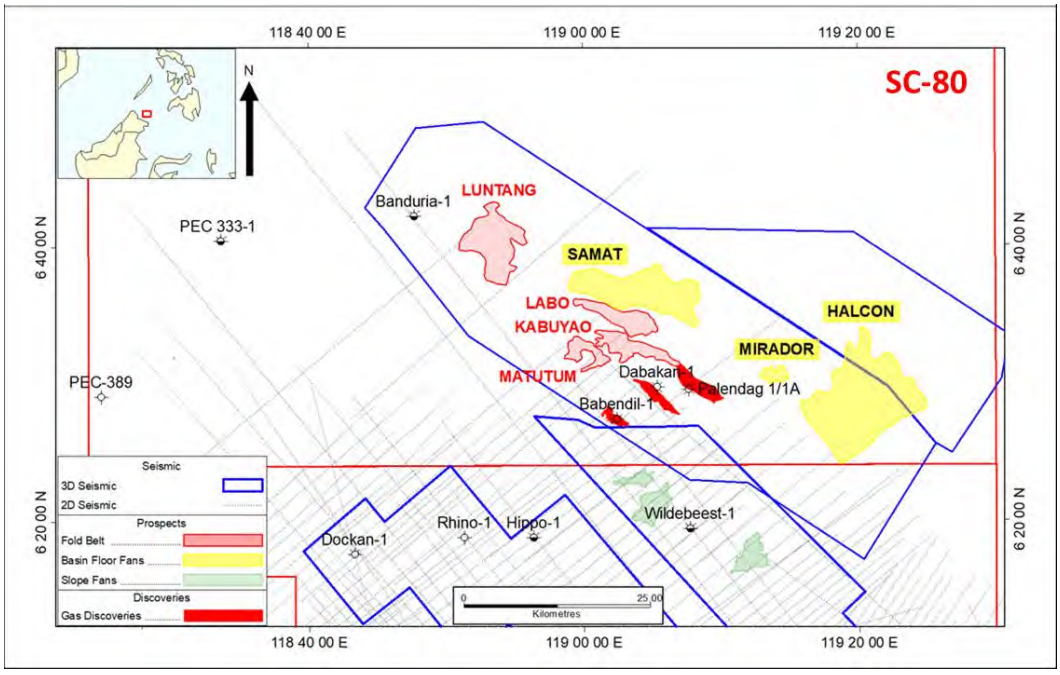

Figure 3-38: Location of SC-80 discoveries and prospects

Source: Tetragon Energy

3.6.2.1 Labo

Labo is located approximately 10 km from the Palendag discovery. It features a structural and stratigraphic trap similar to those of Dabakan and Palendag. Structural closure is dependent on a thrust fault to the north (Figure 3-39) and lateral stratigraphic sealing to the northwest and southeast. The water depth in the area is 2,400 m, and the structural crest is located approximately 600 m below the seabed. The main amplitude events in levels L1, L2, and L3 are stacked. Each level is considered an independent reservoir unit.

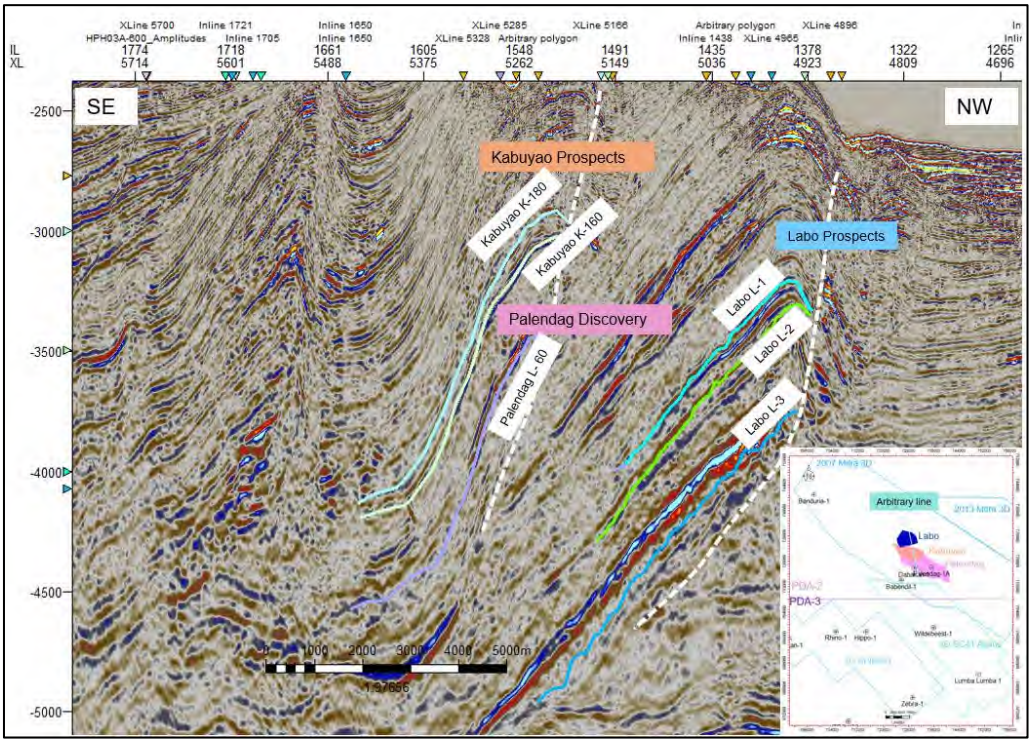

Figure 3-39: Crossline showing the intervals for Labo, Kabuyao and Palendag

Note: Labo prospect intervals labelled L1, L2 and L3, Kabuyao prospect intervals labelled K-160 and K- 180, and Palendag intervals labelled L-60

Labo L1 and Labo L2 have been interpreted as multi-level channel systems based on seismic observations and the analysis of RMS amplitude extraction applied to the same data. The interpretation is supported by identifying distinct channel features and stacking patterns, which suggest a complex, multi-story architecture. The use of RMS amplitude enhancement has helped to highlight subtle variations in the seismic response, further confirming the presence of multiple channelised depositional levels within the system (Figure 3-40).

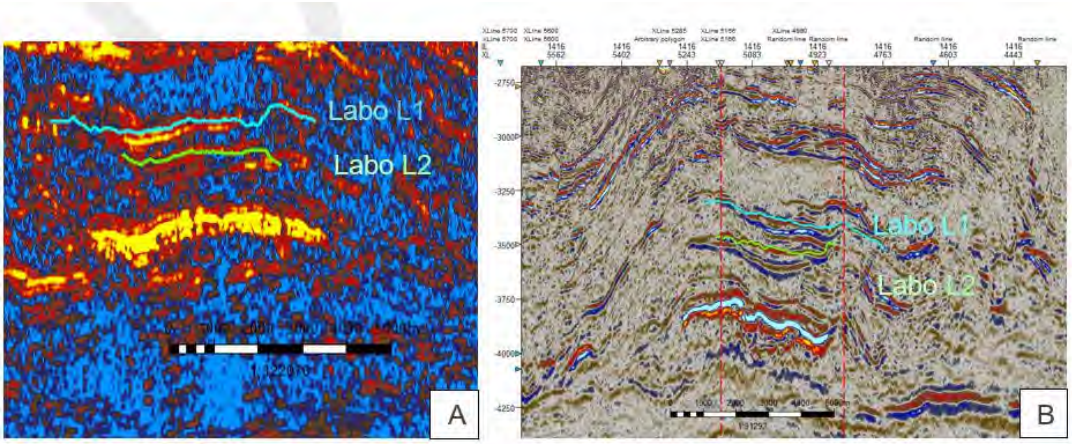

Figure 3-40: A) RMS amplitude extraction. B) Inline showing Labo L1 and Labo L2 prospects

To assess the potential area of the prospect, Sproule ERCE generated maximum amplitude maps for Labo L1, Labo L2, and Labo L3, applying a search window of 10 m. These maps were used to define the lateral extent of the sand bodies within these reservoirs (Figure 3-41).

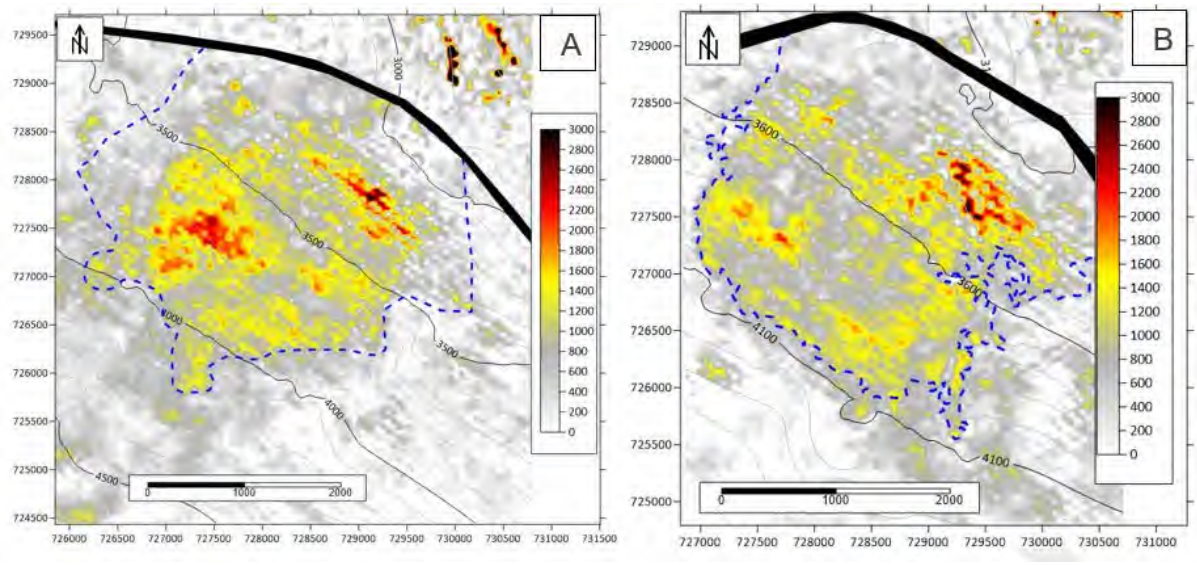

Figure 3-41: Maximum amplitude map for Labo prospect. A) Labo L1. B) Labo L2.

Note: The High Case polygon is shown with a blue dashed line

Sproule ERCE delineated the area in the southwest sector based on the extent of the amplitude map, and it was bounded to the north by the fault observed in the seismic data. This interpretation defines the spatial limits of the reservoir system, ensuring that the fault is recognised as a structural boundary. This polygon has been used for the High Case area, representing an optimistic reservoir scenario. A 70% adjustment was made for the Mid Case, to account for the uncertainty inherent in the methodology used and the variability in the seismic amplitude responses, considering whether these responses correspond to pure hydrocarbons or if there is any lithological overprint. A 50% adjustment was used for the Low Case scenario, reflecting a more conservative estimate and emphasising geological uncertainty. This adjustment is based on uncertainties associated with geological conditions (Table 3-38).

Table 3-38: Labo L1 and Labo L2 areas

Labo	Area (km^2)		
	Low	Mid	High
Labo L1	4.9	6.8	9.7
Labo L2	3.9	5.5	7.9

For Labo L3, Sproule ERCE defined a polygon outlining the central area of maximum amplitude, which was used to represent the Mid Case scenario (Figure 3-42). For the Low Case area, the polygon covers a broader area of the amplitude map and is bounded to the north by the fault observed in the

seismic data. This approach accounted for the potential extension of the reservoir. For the High Case, Sproule ERCE applied a lognormal distribution to capture the higher degree of uncertainty in the prospect's extent. These areas are presented in Table 3-39.

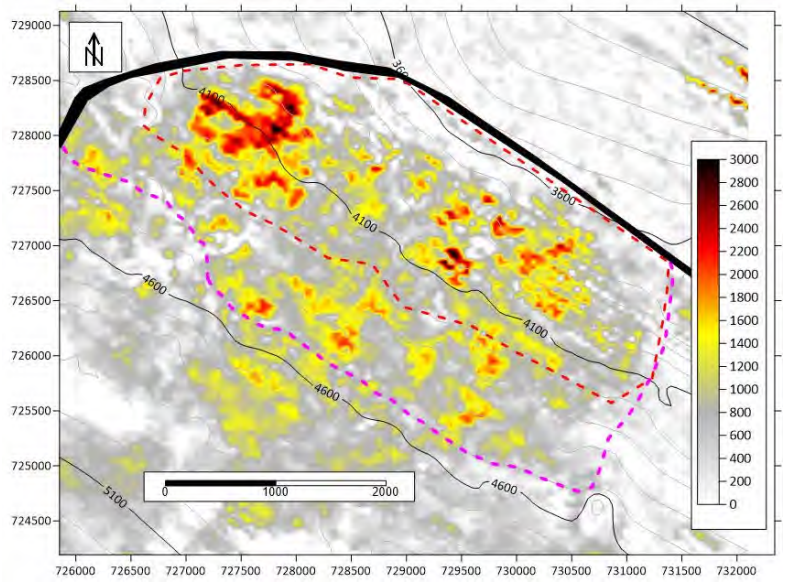

Figure 3-42: Labo L3 maximum amplitude map

Note: The Low Case polygon is shown with a red dashed line; and the Mid Case polygon with a pink dashed line.

Table 3-39: Labo L3 areas

Labo	Area (km^2)		
	Low	Mid	High
Labo L3	4.2	7.1	12.1

The input parameters based on Well Dabakan-1 and Well Palendag-1A are provided in Table 3-40.

Table 3-40: Input parameters for Labo L1, L2 and L3

Prospects	Area (km^2)			Thickness(m)			NTG (fraction)			Porosity (fraction)			Sw (fraction)		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
Labo L1	4.9	6.8	9.7	10	20	35	0.34	0.50	0.65	0.23	0.25	0.27	0.50	0.35	0.22
Labo L2	3.9	5.5	7.9	10	20	35	0.34	0.50	0.65	0.23	0.25	0.27	0.50	0.35	0.22
Labo L3	4.2	7.1	12.1	10	20	35	0.34	0.50	0.65	0.23	0.25	0.27	0.50	0.35	0.22

Prospects	GEF (scf/rcf)			RF (%)		
	Low	Mid	High	Low	Mid	High
Labo L1	310	345	372	50	65	85
Labo L2	310	345	372	50	65	85
Labo L3	310	345	372	50	65	85

3.6.2.2 Kabuyao

The Kabuyao prospect is located on the same fault block as the Palendag discovery in water depths of 1,950 to 2,300 metres. The prospect is a structural/stratigraphic trap similar to the Palendag and Dabakan discoveries. It has structural closure against the thrust fault to the north and is bound to the south by a stratigraphic pinchout, indicated by dimming anomalies. The prospect contains multiple amplitude events identified at Kab-180, Kab-160, Kab-120, and Kab-100 levels, which are treated as a distinct reservoir unit (Figure 3-43).

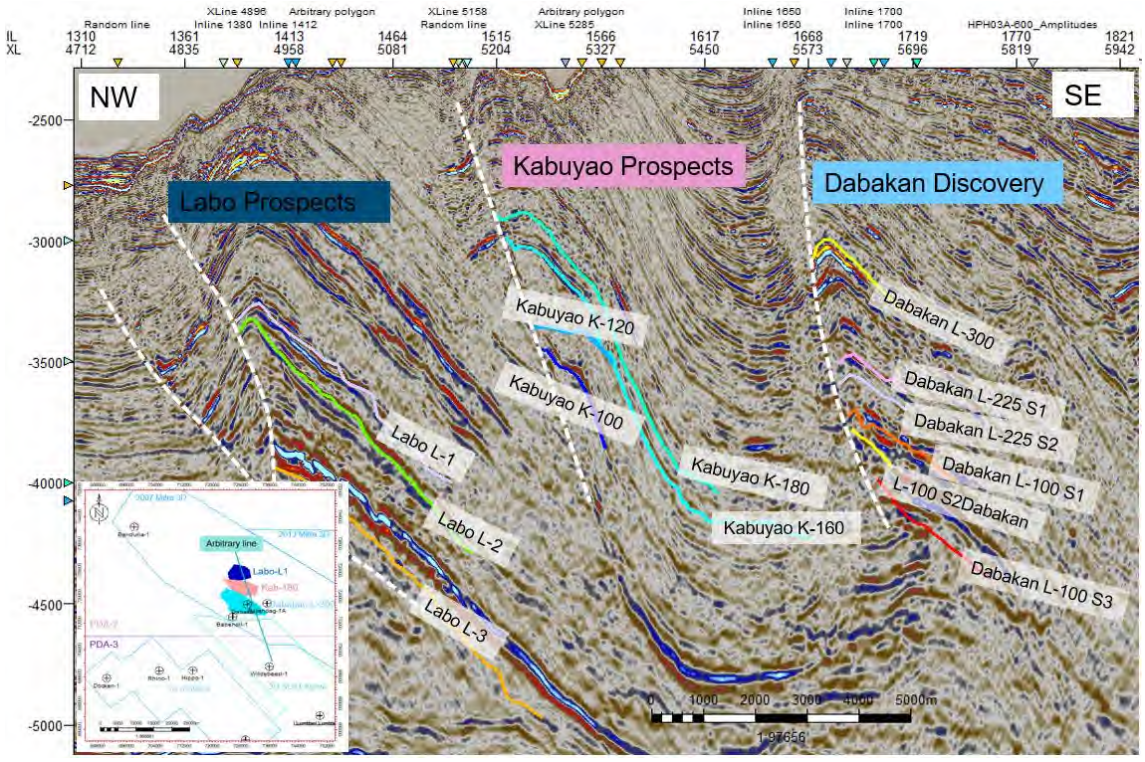

Figure 3-43: Arbitrary line showing Kabuyao and Labo prospects and Dabakan discovery

Note: Labo prospect intervals labelled L1, L2 and L3, Kabuyao prospect intervals labelled Kab-100, Kab-120, Kab-160 and Kab- 180, and Dabakan discovery intervals labelled L-300, L225-S1, L225-S2, L100-S1, L100-S2 and L100- S3

Based on seismic observations, Kabuyao Kab-100, Kab-120, Kab-160, and Kab-180 have been interpreted as stacked channel sand bodies. Sproule ERCE generated maximum amplitude maps for each prospect using a search window of 10 metres to estimate the area for each reservoir. These maps were designed to help define the lateral extent of the sand bodies within these reservoirs.

For Kabuyao Kab-100, Kab-120, Kab-160, and Kab-180 Sproule ERCE delineated the area in the southern sector based on the 3,500 mTVDSS, 3,300 mTVDSS, 3,250 mTVDSS and 3,700 mTVDSS depth contours, respectively, combined with the amplitude map. To the north, the area was bounded by the fault observed in the seismic data. This interpretation helped define the spatial limits of the reservoir system, ensuring that the fault was recognised as a structural boundary. In the case of Kab-100, the defined polygon is within the amplitude map, but the prospect area remains fully covered, encompassing the high-recovery uncertainty zone.

This High Case represents an optimistic reservoir scenario, associated with the full extent of the seismic amplitude responses. For the Mid Case a 70% adjustment was applied to reflect both the uncertainty inherent in the methodology used and the variability in the seismic amplitude responses, considering whether these responses correspond to pure hydrocarbons or if there is any lithological overprint. A 50% adjustment was used for the Low Case scenario, reflecting a more conservative estimate and emphasising geological uncertainty (Figure 3-44).

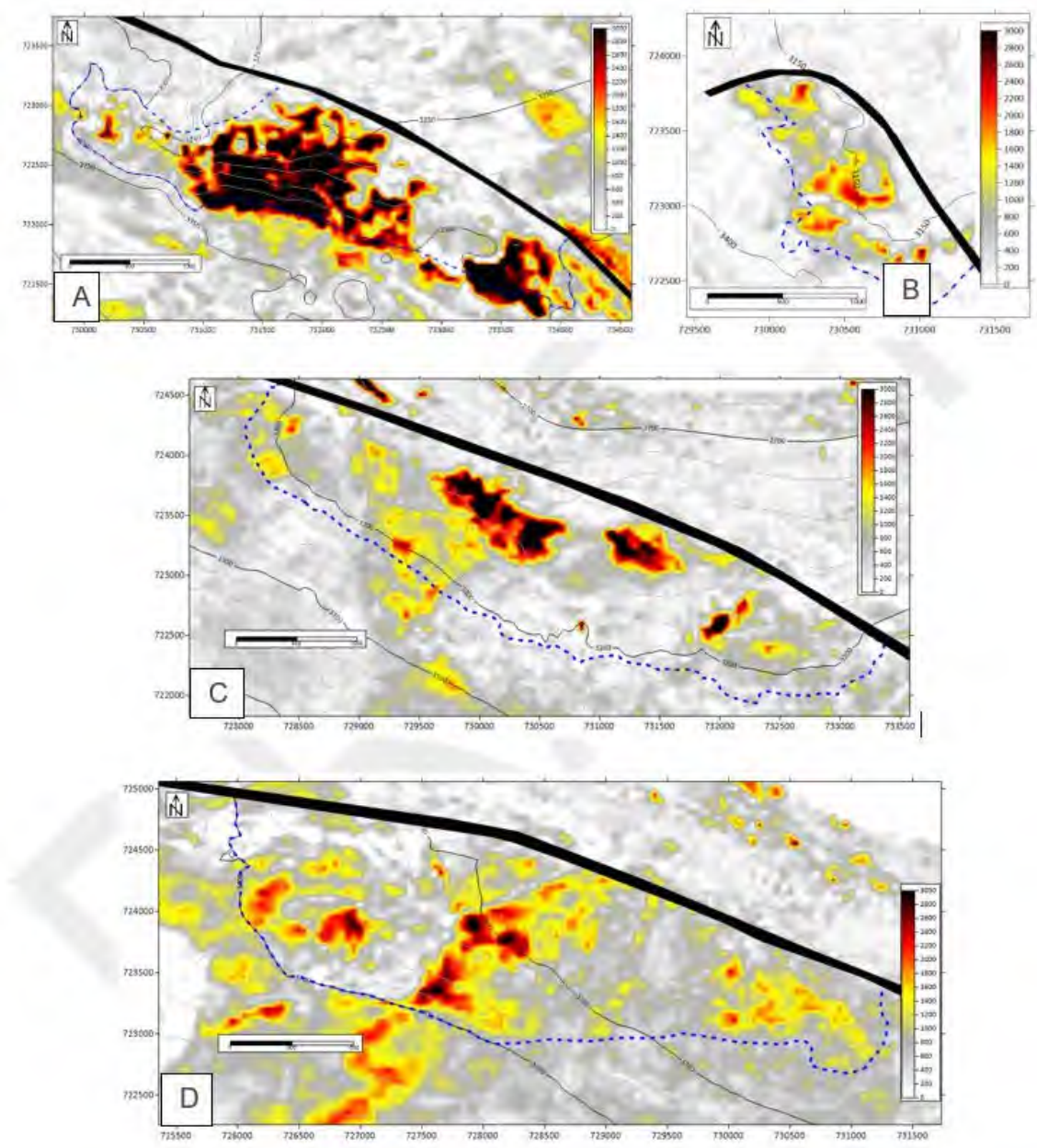

Figure 3-44: Maximum amplitude map for Kabuyao prospect A) Kabuyao Kab-100. B) Kabuyao Kab-120. C) Kabuyao Kab-160. D) Kabuyao Kab-180.

Note: The High Case polygon is shown with a blue dashed line

The areas obtained for each prospect are detailed Table 3-41 and the input parameters based on Well Dabakan-1 and Well Palendang-1A are provided in Table 3-42.

Table 3-41: Kabuyao prospects area

Kabuyao	Area (km^2)		
	Low	Mid	High
Kab-100	1.7	2.3	3.3
Kab-120	0.6	0.8	1.2
Kab-160	2.9	4.6	5.8
Kab-180	3.4	4.7	6.7

Table 3-42: Input parameters for Kabuyao prospects

Kabuyao	Area (km^2)			Thickness(m)			NTG (fraction)			Porosity (fraction)			Sw (fraction)		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
Kab-100	1.7	2.3	3.3	10	20	35	0.34	0.50	0.65	0.23	0.25	0.27	0.50	0.35	0.22
Kab-120	0.6	0.8	1.2	10	20	35	0.34	0.50	0.65	0.23	0.25	0.27	0.50	0.35	0.22
Kab-160	2.9	4.1	5.8	10	20	35	0.34	0.50	0.65	0.23	0.25	0.27	0.50	0.35	0.22
Kab-180	3.4	4.7	6.7	10	20	35	0.34	0.50	0.65	0.23	0.25	0.27	0.50	0.35	0.22

Kabuyao	GEF (scf/rcf)			RF (%)		
	Low	Mid	High	Low	Mid	High
Kab-100	280	296	308	50	65	85
Kab-120	280	296	308	50	65	85
Kab-160	280	296	308	50	65	85
Kab-180	280	296	308	50	65	85

3.6.2.3 Halcon

The Halcon prospect is located on the footwall of the frontal thrust east of the Palendag discovery, at a water depth of approximately 2,800 metres. Halcon is a basin floor fan body derived from an amplitude anomaly. This geological setting is characterised by sediment deposition in a deepwater environment, where gravity-driven sediment flows accumulate at the basin floor, which can be identified in seismic data. It represents a combination of structural and stratigraphic trapping mechanisms, with a low-relief anticlinal structure that provides structural closure in the Low Case.

This evaluation focuses exclusively on the Halcon 5C prospect. While potential targets have been identified at levels 5C and 4, only the 5C target is being evaluated in detail. At the 5C target, only the top and bottom of the amplitude package have been interpreted, suggesting the possibility of multiple stacked sandstone layers (Figure 3-45).

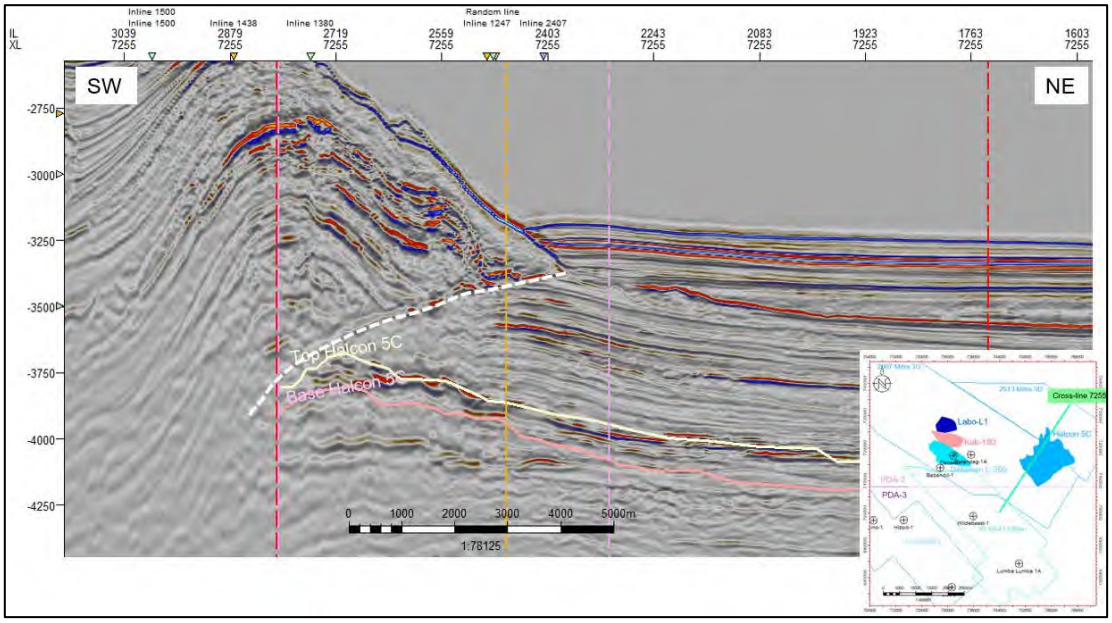

Figure 3-45: Crossline 7255 showing Halcon 5C

Note: Low Case polygon is indicated by yellow lines, Mid Case polygon by pink lines, and High Case polygon by red lines.

Sproule ERCE generated RMS amplitude maps for Halcon 5C, applying a search window of 10 m. This map was used to define the lateral extent of the reservoir (Figure 3-46).

Based on seismic data and the amplitude map, Sproule ERCE delineated the Low, Mid, and High polygons for the prospect, using the seismic amplitude data to define the extent of the reservoir. The polygons are constrained to the southern boundary by the fault observed in the seismic data, which serves as a structural limit for the reservoir system.

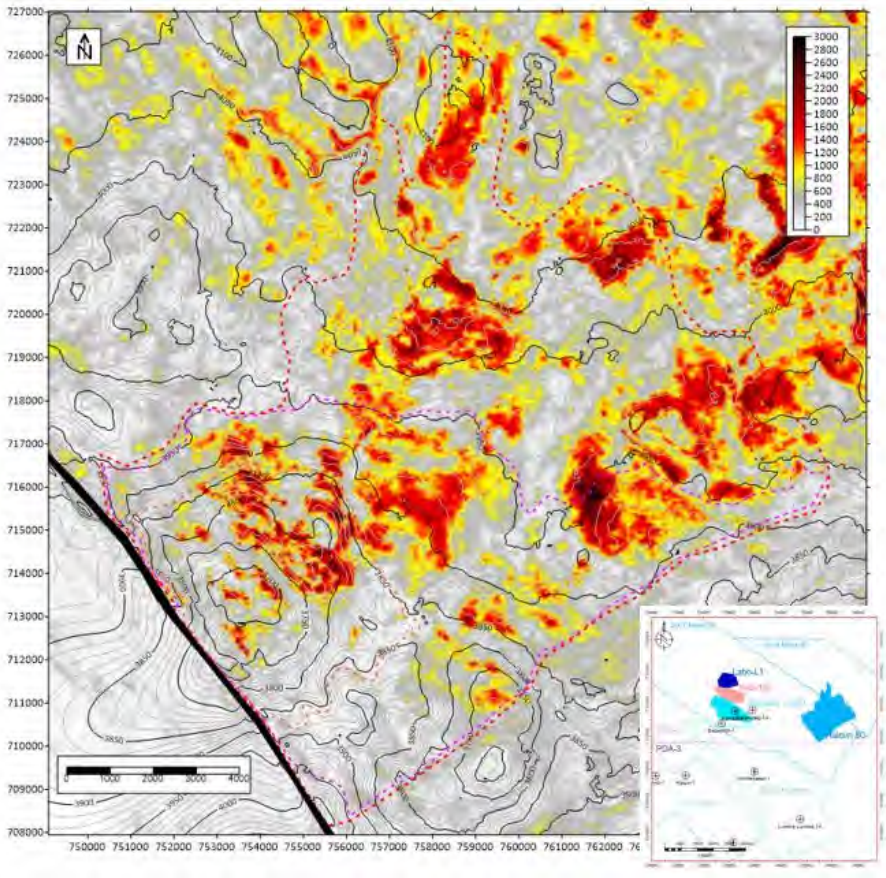

Figure 3-46: RMS amplitude map for Halcon prospect

Note: Outlined polygons represent different volumetric cases: Low Case (orange dashed line), Mid Case (pink dashed line), and High Case (red dashed line).

The estimates of area for the Halcon 5C prospect are detailed below (Table 3-43).

Table 3-43: Halcon 5C area

Halcon	Area (km^2)		
	Low	Mid	High
Halcon 5C	23.8	76.4	144.1

Sproule ERCE used the Top Halcon 5C and Base Halcon 5C depth maps and the polygons to delimit the Low, Mid, and High Case regions in order to calculate the corresponding Low, Mid, and High GRV. This approach incorporated multiple stacked sandstone layers.

Sproule ERCE created an RMS amplitude section of Crossline 7251 highlighting the orange-coloured horizon (between the top and base of the grids), showing the extent and thickness of the sandstone layers. These layers are considered a single reservoir interval for resource estimation, providing insights into the formation's continuity and potential hydrocarbon-bearing capacity (Figure 3-47).

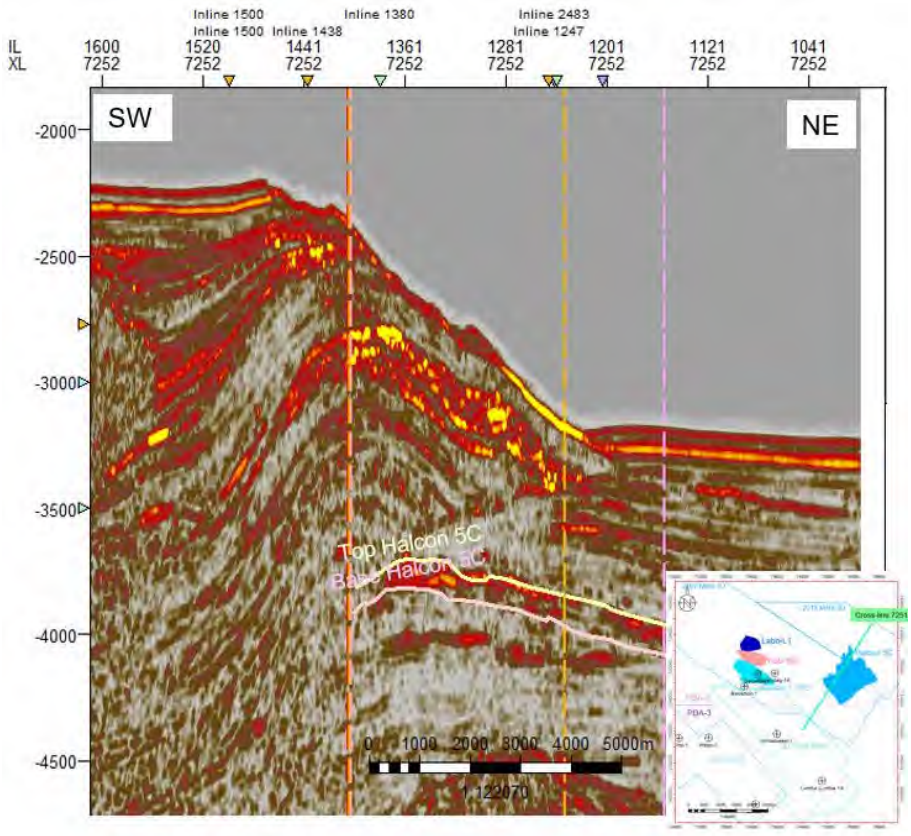

Figure 3-47: Halcon RMS amplitude of Crossline 7251

Note: Thickness of the sandstone layers is highlighted. Polygons represent the Low area (yellow lines), Mid area (pink lines), and High area (red lines

The input parameters for Halcon, based on Well Dabakan-1 and Well Palendag-1A, are provided in Table 3-44.

Table 3-44: Input parameters for Halcon 5C

Halcon	GRV (MMm3)			NTG (fraction)			Porosity (fraction)			Sw (fraction)		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
Halcon 5C	1221	4362	11771	0.21	0.44	0.67	0.21	0.24	0.27	0.50	0.35	0.19

Halcon	GEF (scf/rcf)			RF (%)		
	Low	Mid	High	Low	Mid	High
Halcon 5C	331	361	385	60	70	85

3.6.3 Block SC-81 Prospective Resources

Block SC-81 is covered by both 3D and 2D seismic data, with Wells Lumba-Lumba-1/1A and Wildebeest-1 drilled on the block. Well Wildebeest-1 successfully recovered an oil sample via MDT, showing indications of gas. The prospects and leads are primarily stratigraphic traps, while in the outer area, where only 2D seismic coverage is available, structural closures predominate (Figure 3-48).

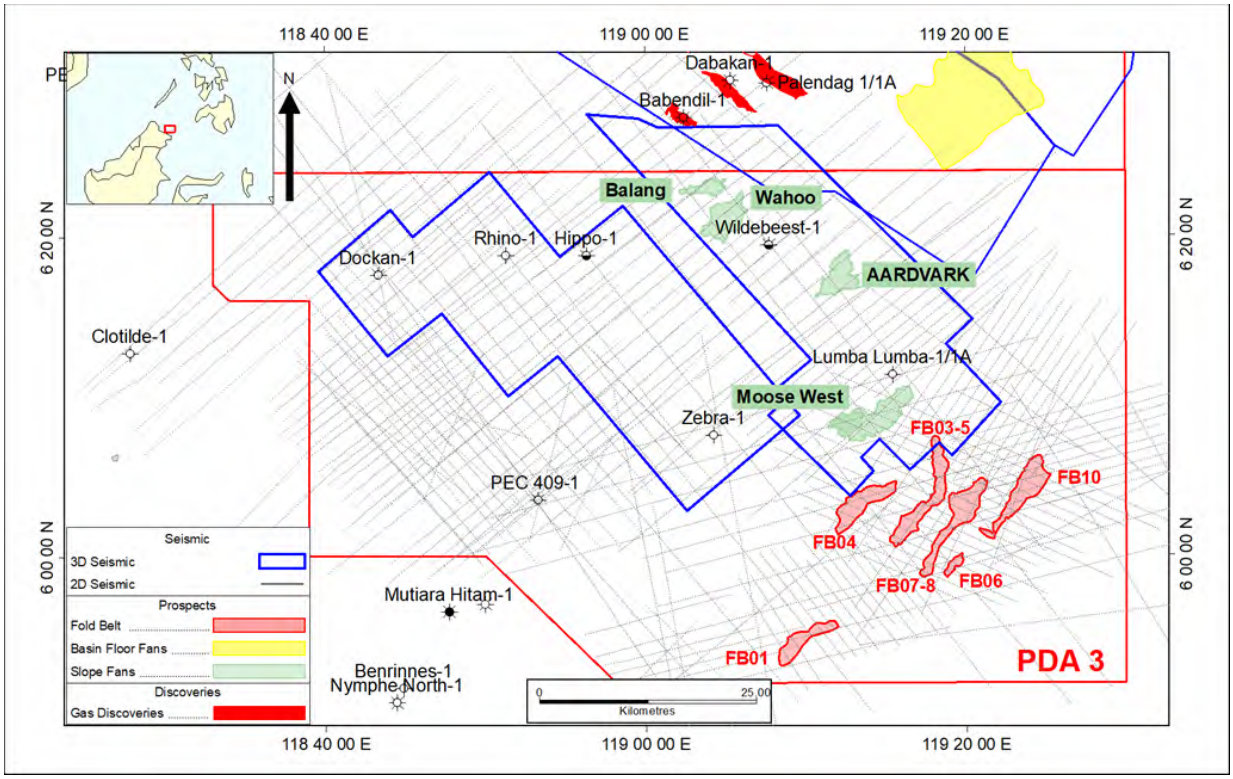

Figure 3-48: Map showing the location of SC-81 and SC-80 Blocks, the extension of the 3D and 2D seismic and the location of the prospects in the area

Source: Tetragon Energy

3.6.3.1 Aardvark

Aardvark is located between Wells Lumba Lumba-1 and Wildebeest-1. The reservoir is at an approximate depth of 1,760 mTVDSS and is a stratigraphic trap. It is situated at a water depth of approximately 110 metres.

The Aardvark prospect is part of the slope channels in the Sandakan Basin. The formation of these slope channels is influenced by various factors, including tectonic activity, sea level fluctuations, and sediment supply. These channels can be identified in seismic data by their distinctive morphology, typically appearing as elongated, sinuous features, which indicate the pathways of sediment transport (Figure 3-49).

The Aardvark prospect and Wells Wildebeest-1 and Lumba Lumba-1 are further inboard of the other discoveries, prospects and leads and carry a risk on hydrocarbon phase. Well Wildebeest-1

encountered oil shows (confirming the presence of paraffinic crude oils, low in sulfur and with light to medium gravity of 38.8–41.8° API) and many inboard wells also encountered oil and gas shows. Due to this phase risk both gas and oil volumetric scenarios have been calculated.

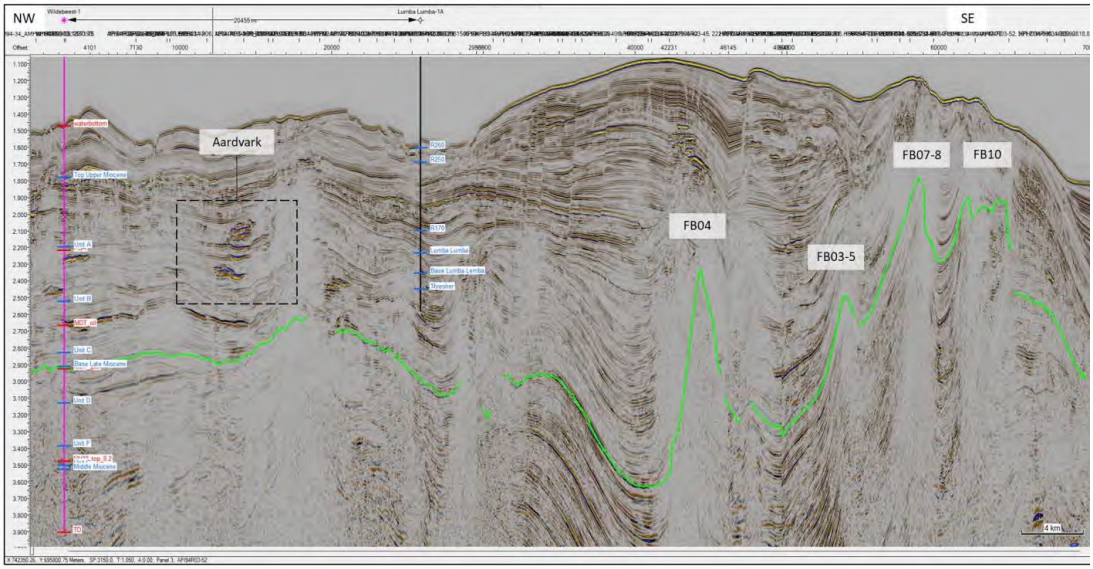

Figure 3-49: Arbitrary line showing the Aardvark prospect

Source: Tetragon Energy

Sproule ERCE created a RMS amplitude map using the reservoir's top and base. This map helped determine the spatial distribution, allowing for the creation of a polygon used to represent the High Case (Figure 3-50). This delineation represents an optimistic reservoir scenario, within the range of uncertainty. For the Mid Case a 70% adjustment was applied to reflect both the uncertainty inherent in the methodology used and the variability in the seismic amplitude responses, considering whether these responses correspond to hydrocarbons or if there is any lithological overprint. A 50% adjustment was used for the Low Case scenario, reflecting a more conservative estimate and geological uncertainty. This adjustment is based on uncertainties associated with geological conditions.

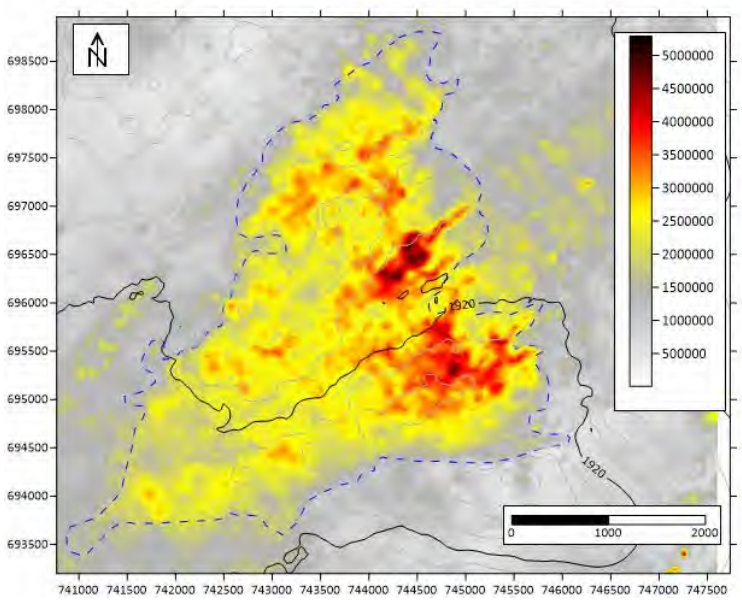

Figure 3-50: Aardvark RMS amplitude map

Note: The High Case polygon is shown with a blue dashed line.

A RMS amplitude section of Inline 1680 (

Figure 3-51) highlights the orange-coloured amplitudes between the Top and Base Aardvark grids, showing the extent and thickness of the sandstone layers. These layers are considered to be a single reservoir interval for resource estimation, providing valuable insights into the continuity and potential hydrocarbon-bearing capacity of the formation The range of areas estimated for Aardvark is given in Table 3-45.

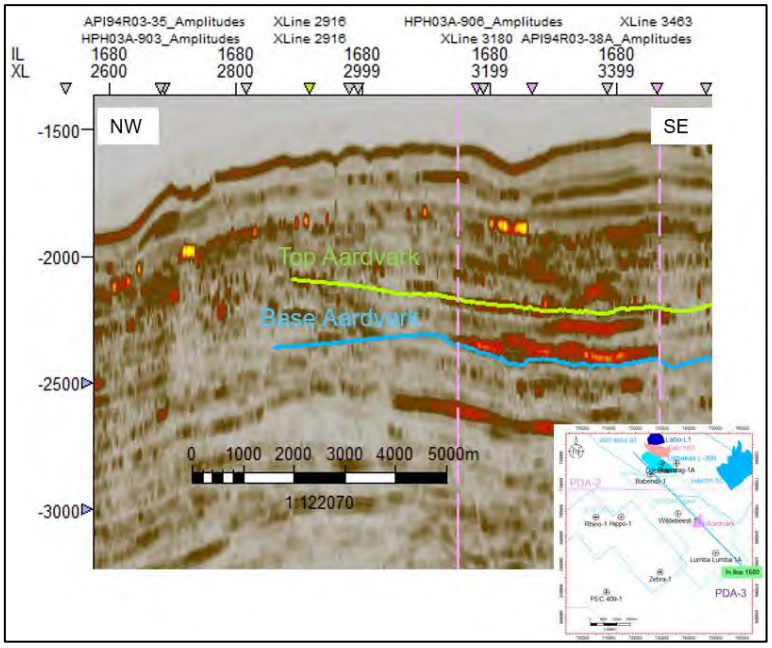

Figure 3-51: RMS amplitude of Inline 1680

Note: The High Case polygon is shown with a pink line.

Table 3-45: Aardvark prospect area

	Area (km²)		
	Low	Mid	High
Aardvark	6.4	8.9	12.7

Sproule ERCE calculated the High GRV (Gross Rock Volume) using the top and base Aardvark depth maps and the High Case polygon. As with the area, Sproule ERCE applied a 70% and 50% reduction to obtain the Mid Case and Low Case, respectively.

The input parameters based on Well Dabakan-1, Well Palendag-1A and Well Wildebeest-1 are provided in (Table 3-46).

Table 3-46: Input Parameters for Aardvark

SC-81	GRV (MMm3)			NTG (fraction)			Porosity (fraction)			Oil/Gas Sw(fraction)		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
Aardvark	295	412	589	0.2	0.4	0.5	0.18	0.21	0.24	0.50	0.35	0.19

SC-81	GEF (scf/rcf)			Gas RF (%)			Bo (v/v)			Oil RF (%)		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
Aardvark	203	270	316	60	70	80	1.24	1.33	1.42	20	30	40

3.6.4 Risk (Chance of Success) - Sandakan Basin

Sproule ERCE evaluates the varying risk levels associated with the analysed prospects: Labo, Kabuyao, Halcon, and Aardvark. Each prospect presents different geological risks related to the source, trap, reservoir, and seal integrity (Table 3-47).

Kabuyao is considered to have a stronger source potential, as it is located within the same fault block as the Palendag discovery. This fault block features a sub-structural stratigraphic trap, similar to the well-established Palendag and Dabakan discoveries, suggesting a more favourable migration and charge scenario. Labo, on the other hand, is not positioned within the same fault block, which introduces a higher source risk compared to Kabuyao. However, it shares a similar trap, reservoir, and seal configuration, maintaining moderate exploration potential.

Halcon has a robust structural closure with a three-way dip closure against a fault, which reduces trap risk. However, its large areal extent introduces reservoir continuity risk, and the absence of a nearby well further adds uncertainty regarding reservoir quality and charge efficiency.

Aardvark presents a higher trap and reservoir risk as it lacks a clear structural closure, relying on stratigraphic lateral and up dip seals, increasing the uncertainty regarding hydrocarbon accumulation. Based on the offset wells where Well Wildebeest-1 encountered oil shows and the SC-80 discoveries to the north encountering gas, Sproule ERCE applies a 50% phase risk for oil versus gas to the Aardvark prospect, leading to a 10% chance of finding gas and a 10% chance of finding oil.

Table 3-47: Evaluation Risk for Labo, Kabuyao, Halcon and Aardvark prospects

Prospect	Source	Trap	Reservoir	Seal	COS
Labo	80%	80%	70%	60%	**27%**
Kabuyao	90%	80%	70%	60%	**30%**
Halcon	60%	90%	60%	60%	**19%**
Aardvark	80%	70%	60%	60%	**20%**

3.7 Leads

A Lead is a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect. Several leads have been mapped by Tetragon Energy within Blocks SC-80, -81, and SC-82. Some of these Leads are extensions of, or adjacent to existing prospects. These remain at an early stage of evaluation and have not been independently assessed by Sproule ERCE. Tetragon Energy plans to utilise the primary term of the PSC to reprocess the existing seismic with a view to mature some of the leads into prospects.

A total of seven leads have been identified within Block SC-80, with multiple target reservoirs across two different plays, namely the foldbelt leads along trend from the two discoveries, and the outboard

basin floor fan leads. An additional nine leads are located within Block SC-81 across two separate plays; slope channel complex and toe thrust trend. A summary of the identified leads is presented in the Table 3-48.

Table 3-48: Lead in Blocks SC-80 and SC-81

Licence	Prospect	Interval	Plays	Seismic	Area (km²)
SC-80	Labo	L-3W	Fold Belt	SC56FAR	4.4
	Kabuyao	K-181	Fold Belt	SC56FAR	8.7
	Luntang	Luntang 0	Fold Belt	SC56FAR	3.7
		Luntang 1	Fold Belt	SC56FAR	8.7
		Luntang 2	Fold Belt	SC56FAR	6.4
		Luntang 3	Fold Belt	SC56FAR	13.3
	Matutum	L200	Fold Belt	SC56FAR	0.8
		L300	Fold Belt	SC56FAR	9.3
	Halcon	4E	Basin Floor Fan	3D CGG CBM	9.6
		4W	Basin Floor Fan	3D CGG CBM	2.3
	Mirador	Mirador 4	Basin Floor Fan	SC56FAR	1.4
		L 5C	Basin Floor Fan	SC56FAR	4.8
	Samat	4000 Main	Basin Floor Fan	SC56FAR	14.3
		4000 W	Basin Floor Fan	SC56FAR	3.8
		4200 NW	Basin Floor Fan	SC56FAR	10.8
		4200 SE	Basin Floor Fan	SC56FAR	12.4
		4400	Basin Floor Fan	SC56FAR	8.9
SC-81	Wahoo		Slope Channels	03DAlpine	15.2
	Mirapina- Balang		Slope Channels	03DAlpine	5.2
	Moose West		Slope Channels	03DAlpine	5.3
	Foldbelt	FB01	Toe Thrust Trend	API94R03	11.0
		FB02-5	Toe Thrust Trend	API94R03	19.6
		FB04	Toe Thrust Trend	API94R03	15.5
		FB06	Toe Thrust Trend	API94R03	2.4
		FB07-8	Toe Thrust Trend	API94R03	19.8
		FB10	Toe Thrust Trend	API94R03	18.8

3.7.1 Block SC-80 Leads

3.7.1.1 Labo L3 West

Labo L3 West is located in the northwestern sector of the Labo L3 prospect. This area does not exhibit any structural closure; due to the associated geological uncertainties, it has been classified as a lead rather than a prospect.

Figure 3-52 presents an amplitude map over the lead together with a polygon indicating its areal extent of some 4.4 km^2.

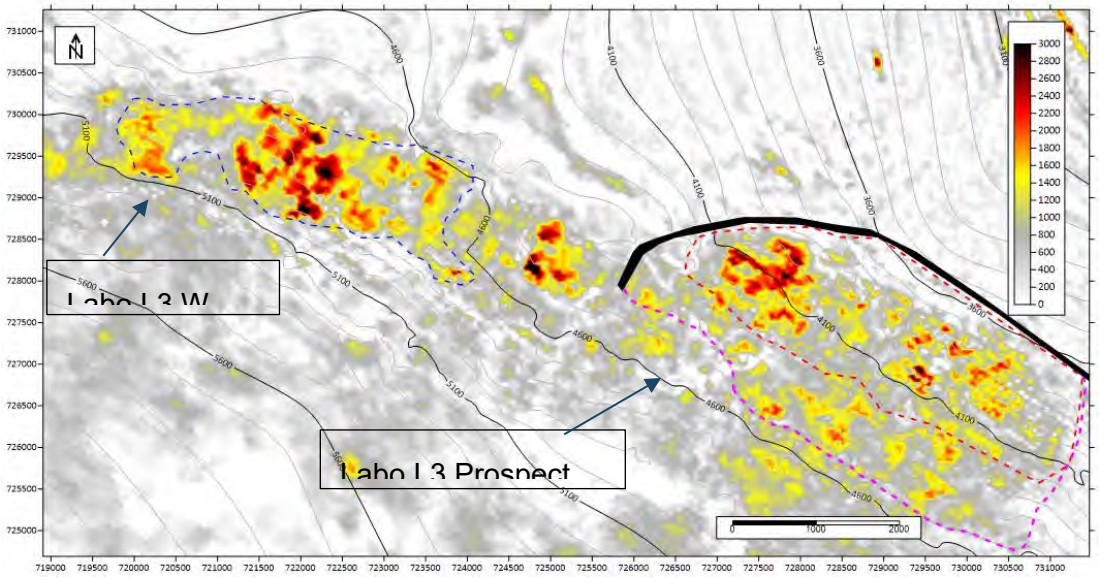

Figure 3-52: Maximum amplitude map showing the Labo L3 West lead next to the Labo L3 prospect

3.7.1.2 Kabuyao K181

Kabuyao K181 is located in the northwestern part of the Kabuyao K180 prospect. This lead is divided into three different areas, none of which exhibit structural closure. Figure 3-53 shows an amplitude map over the lead together with a polygon indicating its areal extent of some 8.7 km^2.

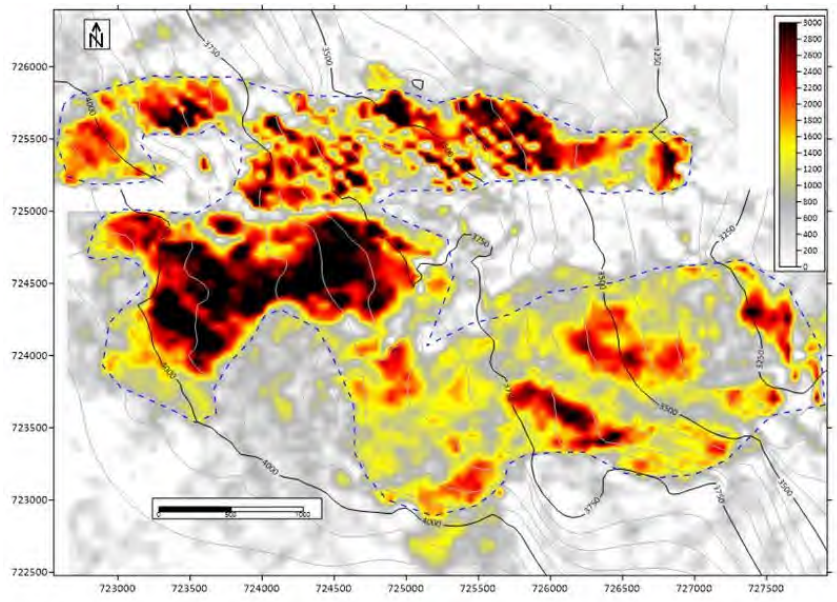

Figure 3-53: Maximum amplitude map showing the Kabuyao K 181 lead

3.7.1.3 Luntang

Luntang is located 22 km from Dabakan discovery, situated on a low-relief thrusted fold, updip and to the southwest of Well Banduria-1. This lead features a structural/stratigraphic trap with structural closure against the northeast thrust fault and a lateral stratigraphic seal through pinchout. Situated at a water depth of approximately 2,000 metres. It contains multiple amplitude events identified at Luntang 0, Luntang 1, Luntang 2, Luntang 3, and the lower cycle of Luntang 3, each treated as distinct units.

Figure 3-54 presents an amplitude map over the lead, together with polygons indicating the areal extent of the maximum amplitude zones for Luntang 0, Luntang 1, Luntang 2, and Luntang 3. For Luntang 0, Luntang 2, and Luntang 3, multiple polygons were generated around adjacent maximum amplitude areas and integrated to estimate the areal extent of each level. In the case of Luntang 1, a single polygon was delineated. The estimated areas are approximately 3.7 km², 8.7 km², 6.4 km², and 13.3 km² for Luntang 0, Luntang 1, Luntang 2, and Luntang 3, respectively.

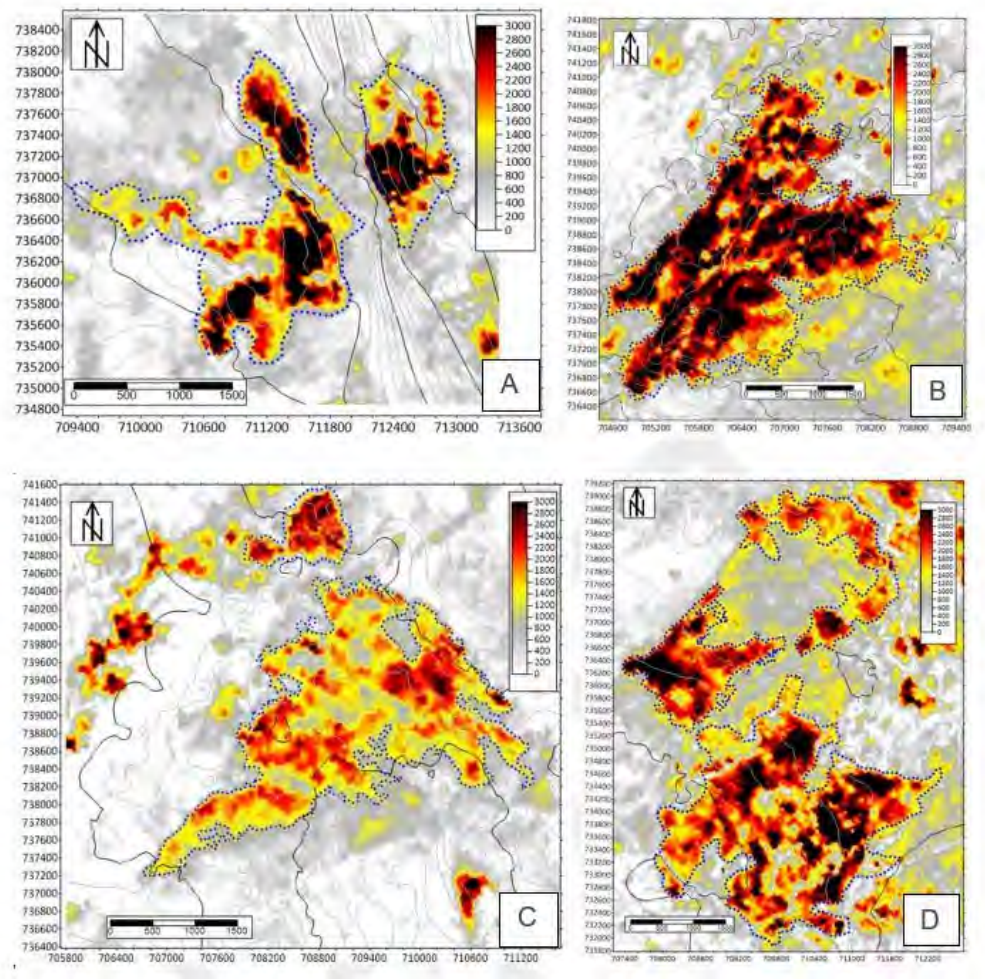

Figure 3-54: Maximum amplitude map showing Luntang lead. A) Luntang 0. B) Luntang 1. C) Luntang 2. D) Luntang 3

3.7.1.4 Matutum

Matutum is located on the same fault block as the Dabakan discovery but on a separate structural culmination to the northwest. This lead features a structural/stratigraphic trap with structural closure against the northeast thrust fault and a lateral stratigraphic seal through pinchout. Situated at a water depth of approximately 1,800 metres, amplitude events have been identified at Matutum L200 and Matutum L300 levels. The Matutum L300 level is correlated to the L300 level in Dabakan, while the Matutum L200 anomaly is in a separate fault block.

Figure 3-55 shows the outline of the lead area. Matutum L300 and Matutum L200 were split into two distinct polygons observed on the amplitude map. The estimated areas are approximately 0.8 km² for Matutum L100 and 0.3 km² for Matutum L300.

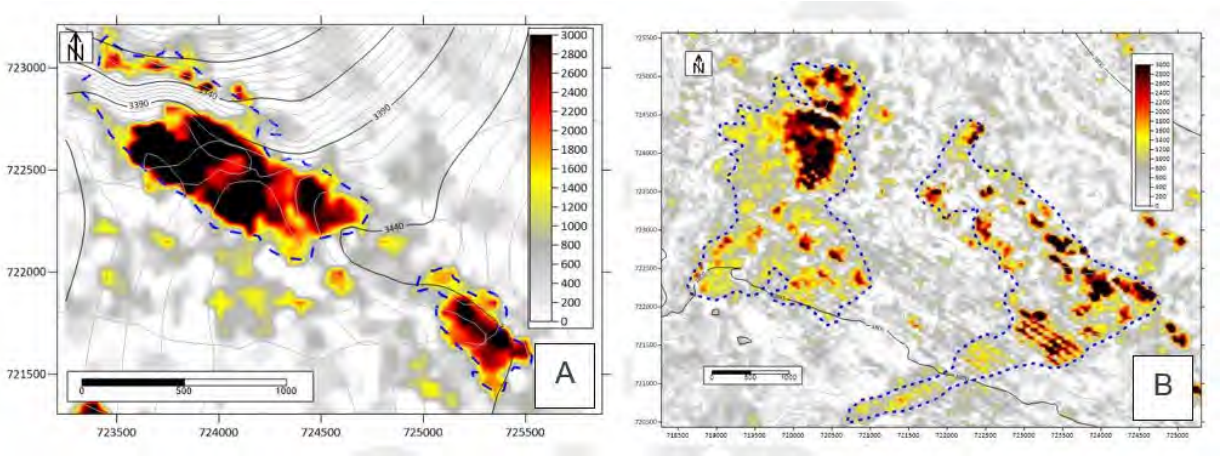

Figure 3-55: Maximum amplitude map showing the Matutum lead. A) Matutum L200 B) Matutum L300

3.7.1.5 Halcon Extension Leads

The Halcon prospect is located on the footwall of the frontal thrust to the east of the Mirador Lead. As illustrated in Figure 3-56, the lead area has been subdivided into two distinct polygons- Halcon 4E and Halcon 4W -based on the interpretation of the maximum amplitude map of Halcon 4. The estimated areas are approximately 2.3 km² for Halcon 4E and 0.6 km² for Halcon 4W.

This subdivision reflects amplitude variations observed in the seismic data, which indicate potential differences in reservoir distribution between the two areas. Since neither Halcon 4E nor Halcon 4W demonstrates structural closure, each has been classified as a separate lead.

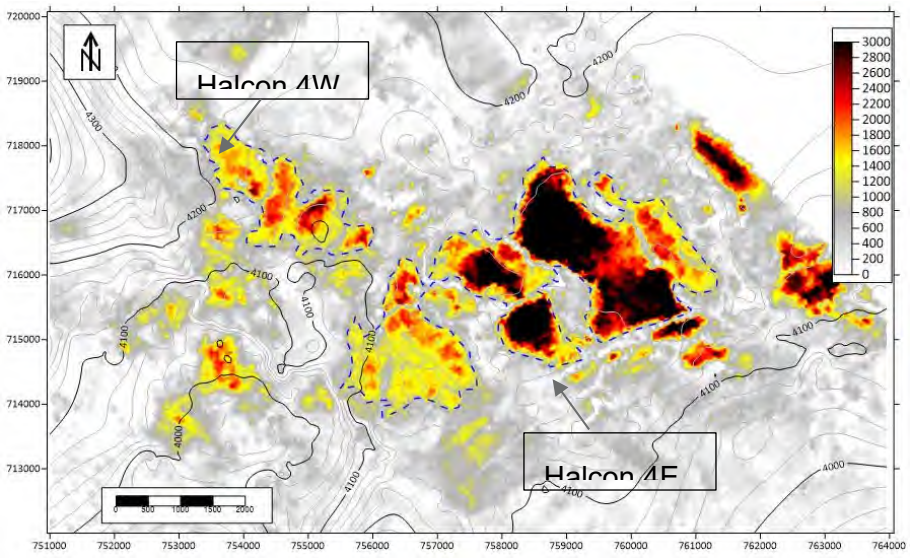

Figure 3-56: Maximum amplitude map showing the Halcon 4E and 4W

3.7.1.6 Mirador

This lead features a structural/stratigraphic trap with a three-way dip closure in the footwall of a west-dipping frontal thrust fault. It contains a basin floor fan body derived from an amplitude anomaly (amplitude package). A cluster of amplitude events has been identified at Mirador Level 5C and Mirador Level 4. Each amplitude anomaly is treated as a single reservoir unit.

Figure 3-57 shows the outline of the anomaly areas. Polygons were delineated around the amplitude responses observed on the map. The estimated areas are approximately 4.8 km² for Mirador 5C and 1.4 km² for Mirador 4.

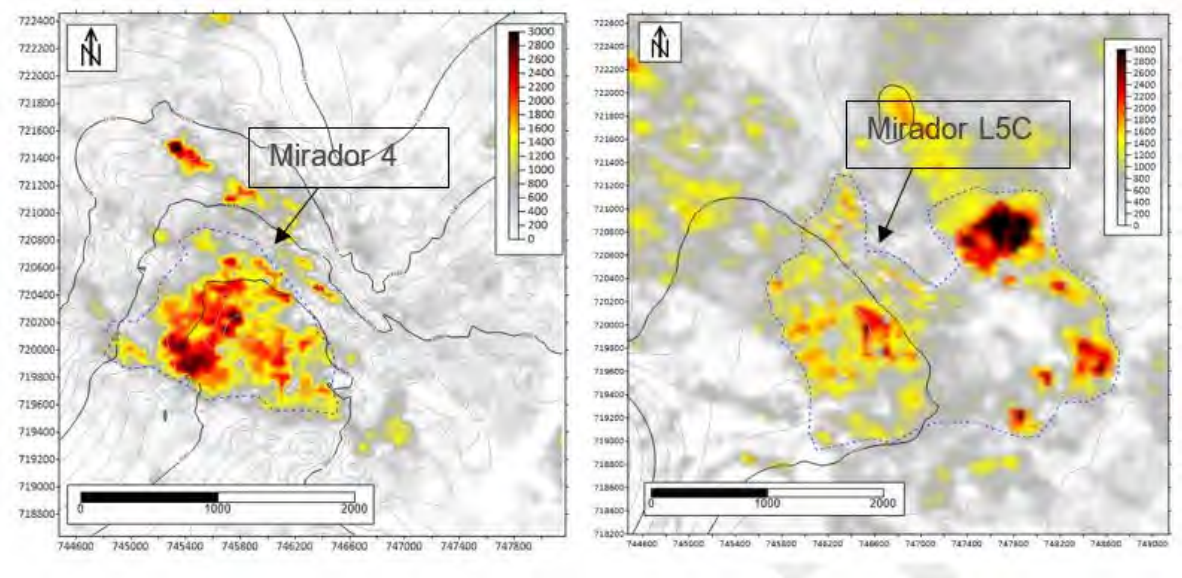

Figure 3-57: Maximum amplitude map showing the Mirador lead. A) Mirador 4. B) Mirador L5C

3.7.1.7 Samat

This lead features a structural/stratigraphic trap with a large but subtle three-way dip closure in the footwall of a west-dipping frontal thrust fault. It contains multiple fan lobes, represented by amplitude anomalies, with a cluster of amplitude events identified at Samat 4000, Samar 4200, and Samat 4400 levels. Each amplitude anomaly is treated as a single reservoir unit. The anomalies are not vertically stacked, meaning they cannot be tested by a single well.

Individual polygons were delineated around the amplitude anomalies associated with each reservoir unit, as shown in Figure 3-58. The estimated areas are approximately 14.3 km² for Samat 4000 Main, 3.8 km² for Samat 4000 West, 10.8 km² for Samat 4200 NW, 12.4 km² for Samat 4200 SE, and 8.9 km² for Samat 4400, respectively.

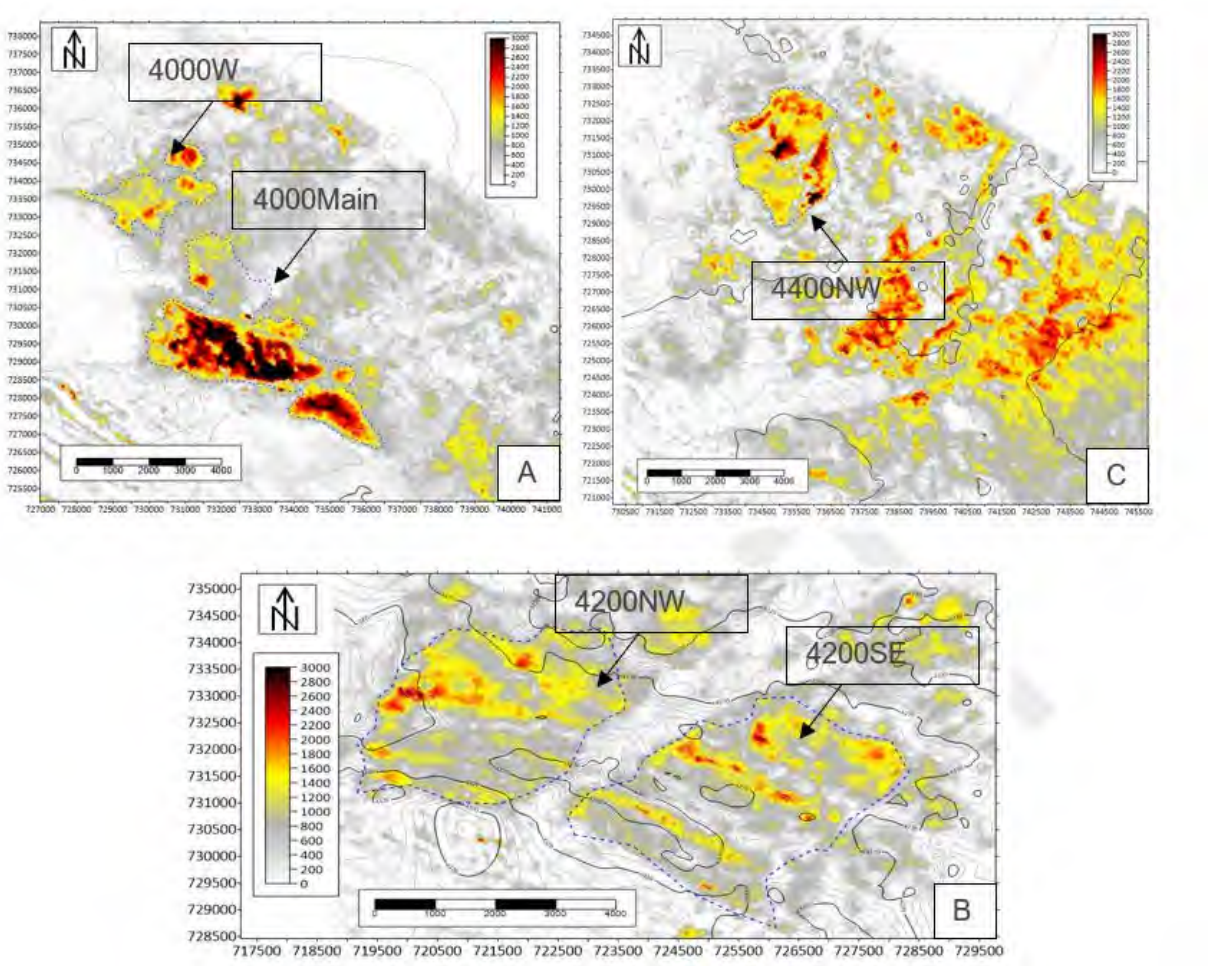

Figure 3-58: Maximum amplitude map showing the Samat lead. A) Samat 4000. B) Samat 4200. C) Samat 4400.

3.7.2 Block SC-81 Leads

The area is covered by both 3D and 2D seismic data, and well data from Wells Lumba-Lumba-1/1A and Well Wildebeest-1, which successfully recovered an oil sample via MDT and showed indications of gas. The leads are primarily stratigraphic traps, while in the outer area, where only 2D seismic coverage is available, structural closures predominate.

3.7.2.1 Wahoo

Wahoo is located north of Well Wildebeest-1. The reservoir lies at an approximate depth of 1,850 mTVDSS and features a structural trap. It is situated at a water depth of approximately 1090 metres.

As in block SC-80, a polygon was created around the RMS amplitude map (Figure 3-59). The interpretation is based on an amplitude anomalies observed in seismic data, which suggest potential reservoir presence but require further evaluation through additional geophysical and geological analysis. The estimated area is approximately 15.2 km².

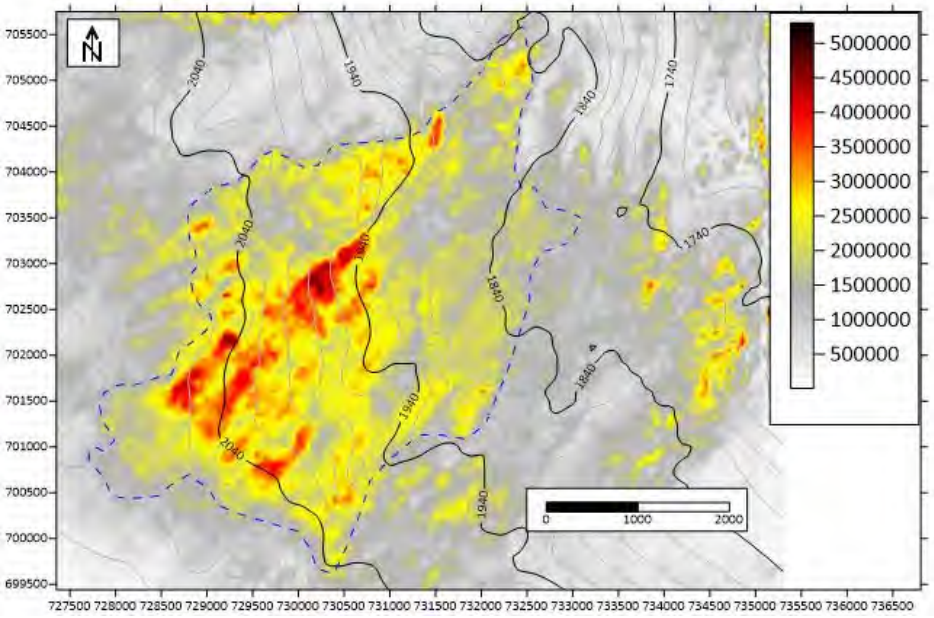

Figure 3-59: Wahoo RMS amplitude map

3.7.2.2 Mirapina-Balang

Mirapina-Balang is located north of Wahoo. The reservoir lies at an approximate depth of 2,000 mTVDSS and features a structural trap. It is situated at a water depth of approximately 110 metres.

A polygon was delineated around the RMS amplitude anomaly to define the interpreted lateral extent of the reservoir, as shown in Figure 3-60. The estimated area is approximately 5.2 km².

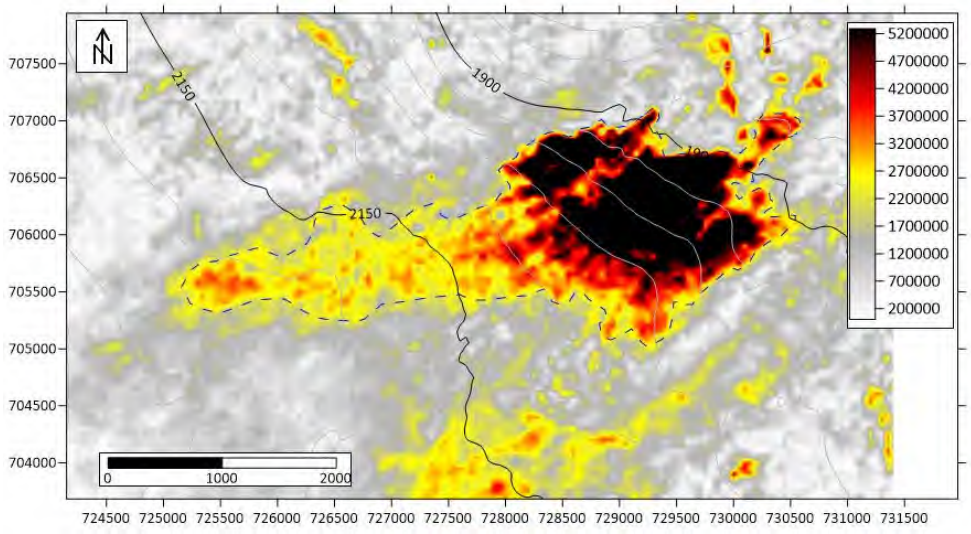

Figure 3-60: Mirapina Balang RMS amplitude map

3.7.2.3 Moose West

Moose West is located south of Wells Lumba Luma-1/1A. The reservoir lies at an approximate depth of 1,520 mTVDSS and features a structural trap. It is situated at a water depth of approximately 780 metres.

A polygon was delineated around the RMS amplitude anomaly to define the interpreted lateral extent of the reservoir (Figure 3-61). The estimated area is approximately 5.3 km².

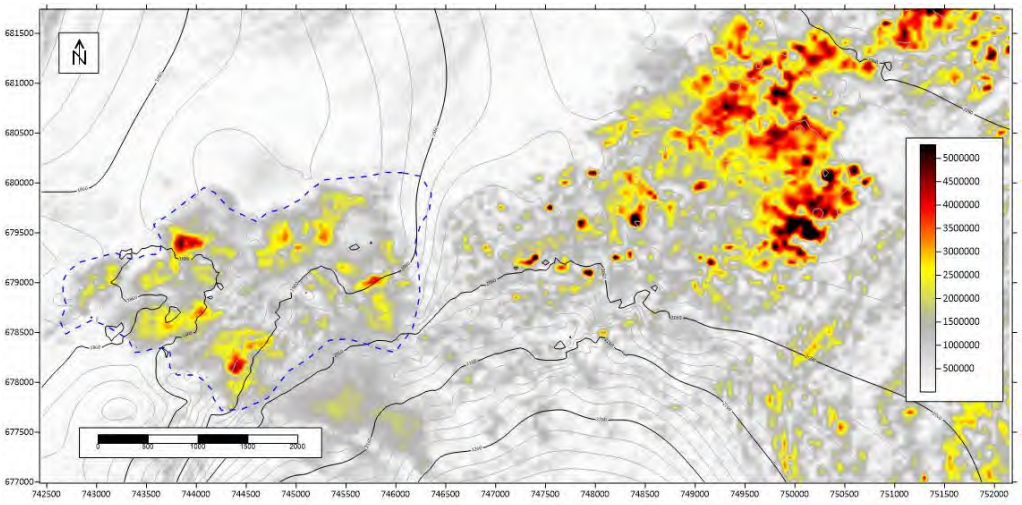

Figure 3-61: Moose West RMS amplitude map

3.7.2.4 Foldbelt

The Foldbelt is located at the southernmost end of the SC-81 block, covered only by 2D seismic data. Six leads with structural closure have been identified in this area, all characterised by a Toe Thrust Trend

Polygons were delineated based on the spill points identified in the depth maps (Figure 3-62) defining the interpreted limits of each lead. The estimated areas are approximately 11.0 km² for Foldbelt FB-01, 19.6 km² for Foldbelt FB-02/05, 15.5 km² for Foldbelt FB-04, 2.4 km² for Foldbelt FB-06, 19.8 km² for Foldbelt FB-07/08, and 18.8 km² for Foldbelt FB-10.

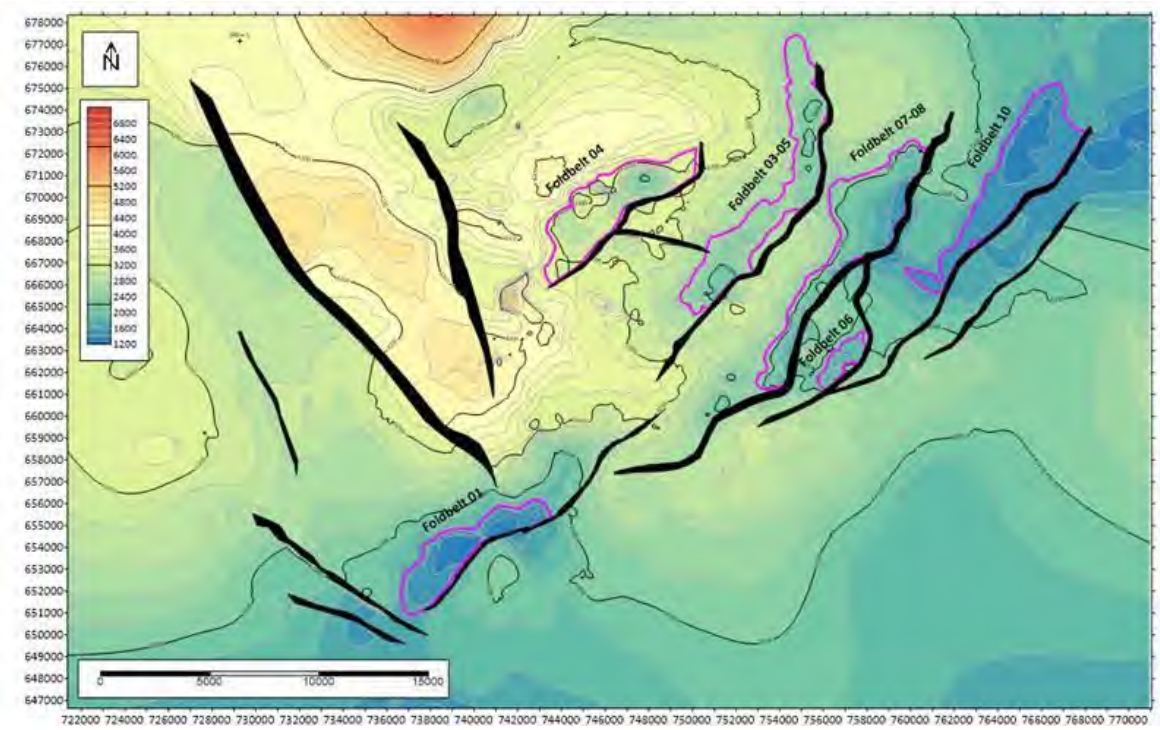

Figure 3-62: Depth map showing the Foldbelt location and the mid case areas

4 Cagayan Basin: Block SC-82

4.1 Introduction

Block SC-82 is a 4,700 km² onshore exploration area situated in the northeastern sector of the Cagayan Basin, within the Cagayan Valley region of Luzon Island, Philippines. In its SW corner it lies adjacent to Block SC-37, which contains the abandoned San Antonio gas field (Figure 4-1). The block is entirely underlain by the Cagayan Basin, containing sedimentary sequences ranging from Paleogene to Miocene age and covering an area of approximately 27,000 km². It lies in a structurally complex setting which is bounded by the Sierra Madre Mountain Range to the east, the Cordillera Central to the west, the Caraballo Mountains to the south, and the Babuyan Channel to the north.

To date, the only production in the basin came from the San Antonio gas field in a Miocene reef facies in SC 37 at the SW margin of the SC-82 block. This field started producing gas at ~ 4 MMscf/d in 1994 and ultimately recovered 3.54 Bscf of gas before being closed in 2008. Gas has also been discovered in the Nassiping structure in the north of the permit.

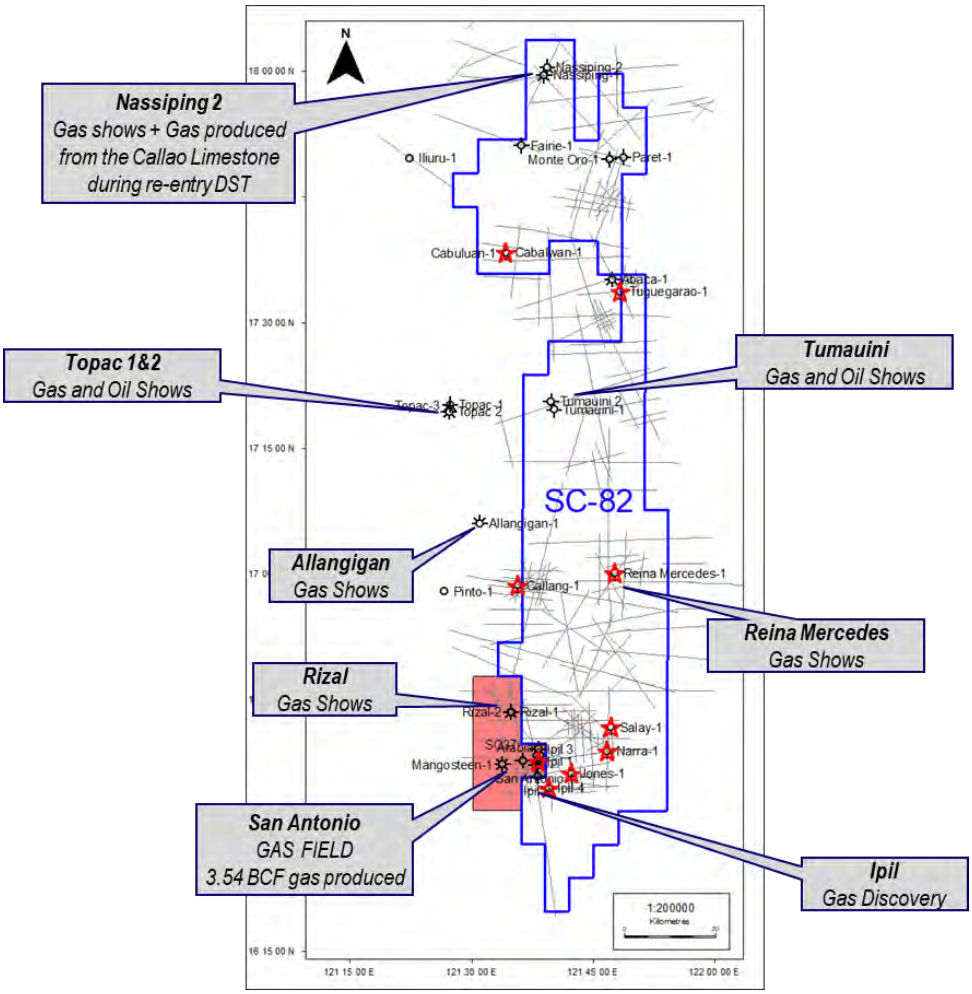

Figure 4-1: Wells drilled in Block SC-82 and SC-37

Source: Tetragon Energy

Tetragon Energy holds a 100% equity interest in the SC-82 permit.

Tetragon Energy's evaluation is based on data provided by the Department of Energy ("DOE") and from other public domain sources. Where data allow, Tetragon Energy has based its interpretation on seismic and well data and various reports provided. In the less explored portion of Block SC-82 where there is limited seismic and well data coverage, the evaluation was aided by reference to certain public domain reports and technical papers.

At this early stage in the work on this new permit, Tetragon Energy has focused its efforts on quality control and checking of the available data and validation of the discovered hydrocarbons and prospectivity of the permit. Following the award, Tetragon Energy is committed to a programme of well data digitising, seismic reprocessing, geophysical data acquisition (Aero Gravity Magnetic) and further geological studies on the permit area. Subject to the outcomes of these studies, Tetragon Energy retains the option to relinquish the licence prior to entering the drilling phase. Otherwise, the programme is expected to culminate in the drilling of an exploration well after seven years, as summarised in Table 4-1.

The work programme approved by the Philippine authorities consists of five sub-phases (SP1 to SP5), with durations dependent on the specific activities proposed within each phase.

ERCE has reviewed Tetragon Energy's interpretation as part of the preparation of this report.

Table 4-1: Tetragon Energy: Work programme summary

Year	Sub Phase No Duration	Work Commitment	Quantity
1	SP1 24 months	Source, secure, and reprocess seismic.	3600 Km
		Source and digitise well data	25 Well
2		G&G and G&A, Geochem	G&A,
3	SP2 24 months	Seismic Interpretation	
		Stratigraphic and structural studies	
		G&G and G&A	
4		Prospect screening for seismic acquisition	
		G&A	
5	SP3 12 months	Geophysical data acquisition	200 Km
		(Aero Gravity Magnetic)	
		G&G and G&A	
6	SP4 12 months	Well planning	
		G&G and G&A	
7	SP5 12 months	Drill Well	1
		G&G and G&A	

4.2 Exploration History

Exploration in the region began in the late 1950's, culminating in a total of 37 wells having been drilled in the basin and 1,523 km of 2D seismic acquired. Of these, 15 wells exhibited varying degrees of oil and/or gas shows, and four wells flowed gas to surface during drill-stem testing.

Drilling began in 1956 with the drilling of the Tumauini Anticline by the Philippine Oil Development Company. This initial well did not yield commercial results. From 1957 to 1961, a U.S. consortium conducted further drilling operations. During this campaign, ten wells were drilled, resulting in two non-commercial dry gas discoveries:

- Well Ipil-1, targeting the Callao Limestone reef, and
- Well Abaca-1, targeting the Lubuagan Sandstone.

Due to the absence of a viable natural gas market at the time, the campaign was suspended in 1961.

Concurrently, the Anglo-Philippine Oil Company drilled Well Nassiping-1 on a surface-defined anticline. The well reached a total depth of 3,197 mMD within the Middle Miocene Lubuagan Formation. Bleeding gas was identified in core cut from poor quality interbedded shaley limestones of the Callao Limestone formation at 2957 mMD. Three DSTs were subsequently conducted at intervals through the Callao Limestone, two of which recovering gassy water and gas–cut mud, but the well was classified as dry.

Exploration resumed in the early 1970s with the Philippine Overseas Drilling Company (Philodrill) drilling Wells Topac-1 and 2, and Allangigan-1 and 2 along the western margin of the basin, near known oil seeps. These wells encountered minor oil and gas shows but failed to result in commercial discoveries.

Between 1976 and 1984, PNOC-Exploration Corporation (PNOC-EC) drilled ten wells, including Well San Antonio-1, which confirmed previous gas shows identified in Well Ipil-1.

In 1981, Total drilled Well Cowrie-1, the only offshore well in the basin, which flowed sub-commercial quantities of gas.

Well Nassiping-2 was drilled in 1984. The well targeted the Middle Miocene Sicalao Limestone, initially interpreted as a reefal carbonate buildup with potential reservoir quality. During drilling, hydrocarbon gas shows were observed within the overlying Upper Miocene Callao Limestone. Log quality was poor, leading to unreliable petrophysical evaluation. The well was suspended due to mechanical problems. In 2012, the well was re-entered and tested the Callao Limestone, flowing gas and formation water at low rates of 0.11 MMscf/d and approximately 100 bbl/d respectively, but again the test was compromised due to mechanical difficulties.

Between 1984 and 1991 activity focused on appraisal of the San Antonio–Ipil gas field. Afterwards, exploration in the basin declined. Since 1991, only two other wells have been drilled, including Well Monte Oro-1 in 2008, which did not result in a commercial discovery.

The San Antonio gas field commenced gas production through the Well San Antonio-1A in 1994. At its peak, the field supplied up to 1 million cubic feet per day to a 3-megawatt power facility, producing 3.54 Bscf gas and supplying 15,000 homes for 14 years before operations ceased in 2008.

4.3 Data Provided

Sproule ERCE has relied upon data and information made available by Tetragon Energy. These data comprise details of 2D seismic data, technical reports, and interpreted data, summarised as follows:

- Kingdom project in time and depth, containing 188 2D seismic lines, horizon and grids interpretation, polygon outline areas of the discoveries and leads.
- Top formation interpretations for 37 wells; of these, 32 wells are located in the Block SC-82, and only 8 wells within the block itself contain available log data.
- Composite Lithologic- Electric log of exploratory Well Nassiping-1(C.E. Allen, September 1961).
- Well Nassiping-1 - Composite Log Image (1961).
- Well Summary log with description remarks Well Nassipping-2- (1984).
- Well Nassiping No 2 - Drilling Synopsis (1984).
- Well Nassiping No 2- Lithologic description (1984).
- Summary of Biostratigraphy and Paleoenvironment of Nassipping No 2. (L.P. Dizon, 1984).
- Micropaleontologic and Biostratigraphic Chart (L.P. Dizon, 1984).
- Well Completion Report- Nassiping-2 (Department of Energy- Philippines, 1984).
- Paleontological Report of Well Nassipping-2 (L.P. Dizon, 1984).
- Final Report Nassipping-2- Vol.1 (Department of Energy –Philippines, 1984).
- Final Report Nassipping-2- Vol.2 (Department of Energy –Philippines, 1984).
- Well Summary- Nassipping-2 (Petro-Canada, 1984).
- Competent Person’s Report Valuation of the Philippine SC 52 (Frontier Oil Corporation, 2013).
- Seismic Re-Interpretation of Service Contract SC52 (Frontier Oil Corporation, 2013).
- Nassipping-2 Re- Interpretation SC52 (Frontier Oil, 2013).
- Evaluation of Callao Limestone, Flow Test and Pressure Buildup-Nassiping Report (MHA Petroleum Consultants LLC).
- Project Economic (Frontier Oil, 2013).

- Nominated Area 11 Philippine conventional Energy Contracting program for petroleum service contract, Cagayan Basin Map.
- Philippines Nominated Areal 11 (SC-82) Cagayan Information Memorandum (Tetragon Energy, 2025).

4.4 Geological Overview

The Cagayan Basin, an asymmetric inter-arc basin, is located between the active Cordillera Central volcanic arc and the inactive Sierra Madre arc in northern Luzon, Philippines. It began forming during the Late Oligocene because of a tectonic transition from a back-arc basin to an inter-arc basin, driven by complex regional tectonic forces. The basin is underlain by a heterogeneous basement composed of ophiolitic, igneous, and metasedimentary rocks ranging from the Cretaceous to the Paleogene. The stratigraphy of the basin is shown in Figure 4-2.

The oldest sedimentary unit of the basin is the Lower Zigzag Formation, deposited during the Early Oligocene. This formation, encountered in wells such as Well Abaca-1, consists primarily of volcaniclastic deposits — tuffs, breccias, and agglomerates — interbedded with conglomerates, sandstones, and siltstones. These materials were mainly derived from andesitic to basaltic volcanic activity, with occasional marine limestones and siltstones indicating fluctuating marine influences during deposition.

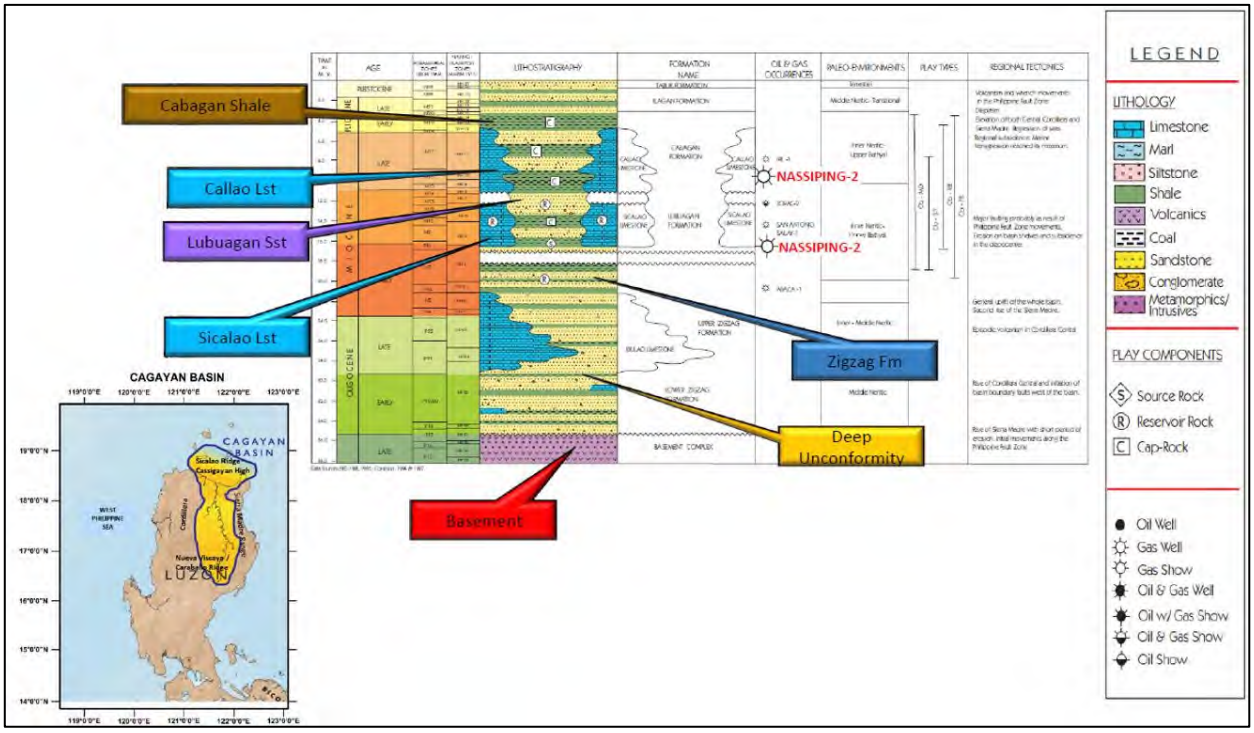

Figure 4-2: Schematic stratigraphic column of the Cagayan Basin

Source: Tetragon Energy

As the basin evolved, the Upper Zigzag Formation marked the transition to more stable marine conditions, characterised by shallow to open marine carbonates and siliciclastic deposits.

The Ibulao Formation, spanning from the Late Oligocene to Early Miocene, is a significant carbonate deposit within the basin. It is predominantly composed of limestones deposited in shallow marine carbonate environments This formation is one of the most important in the basin, acting as a potential hydrocarbon reservoir, especially in areas where it is preserved beneath regional unconformities. Its deposition reflects more stable marine conditions compared to earlier volcanic activity.

From the Early to Middle Miocene, the Cagayan Basin experienced significant subsidence, which led to the deposition of turbidite sequences in a deep marine setting. During this period, the Sicalao Limestone was deposited, characterised by deep marine carbonate deposits that play a key role in hydrocarbon storage due to their porosity and structural positioning. This was followed by the deposition of the Lubuagan Formation, which consists predominantly of volcanic and fluvial sediments, indicating a transition to a more continental environment. The interbedding of these formations reflects the dynamic interplay between marine incursions and continental influence, likely controlled by regional tectonics and changing sea levels.

During the Late Miocene to Early Pliocene, the basin continued to experience subsidence. The Callao Limestone, deposited in the shallow marine environment, is characterised by bioclastic limestone and carbonate deposits that are crucial for hydrocarbon accumulation. It is overlain by the Cabagan Formation, which was deposited in a deeper marine setting, reflecting the ongoing subsidence of the basin and characterised by turbidites in a deep-water environment.

In the Late Pliocene to Pleistocene, the basin transitioned to more terrestrial settings, with the Ilagan Formation representing a shift in depositional conditions. This formation is composed of coarser sediments, reflecting a more fluvial and continental environment. The increased tectonic activity during this period caused uplift and structural deformation along the western margin of the basin, promoting a shift in sedimentation patterns.

In the Pleistocene to Holocene, ongoing tectonic activity in the Cordillera Central and subsequent uplift of the basin led to the deposition of the Tabuk Formation, which consists of volcanic and fluvial sediments. This period reflects a more active terrestrial environment, with erosional processes related to tectonic uplift and the exposure of previously formed structural folds.

Tectonically, the Cagayan Basin exhibits four major unconformities, which are regionally extensive and play an important role in the basin's sequence stratigraphy. These unconformities separate significant sedimentary packages, providing insights into the basin’s tectonic and depositional evolution. Furthermore, the Eocene basement acts as an important seismic and structural marker for understanding the overall structural configuration of the basin.

The geological history of the Cagayan Basin has led to the formation of a structurally diverse region with significant hydrocarbon potential. This potential is especially evident in areas where carbonate platforms are preserved beneath regional unconformities, making these regions targets for future exploration and development

4.4.1 Petroleum System

The Cagayan Basin's hydrocarbon potential is driven by a variety of play concepts influenced by both structural and depositional factors, offering diverse reservoir and trap opportunities (Figure 4-3).

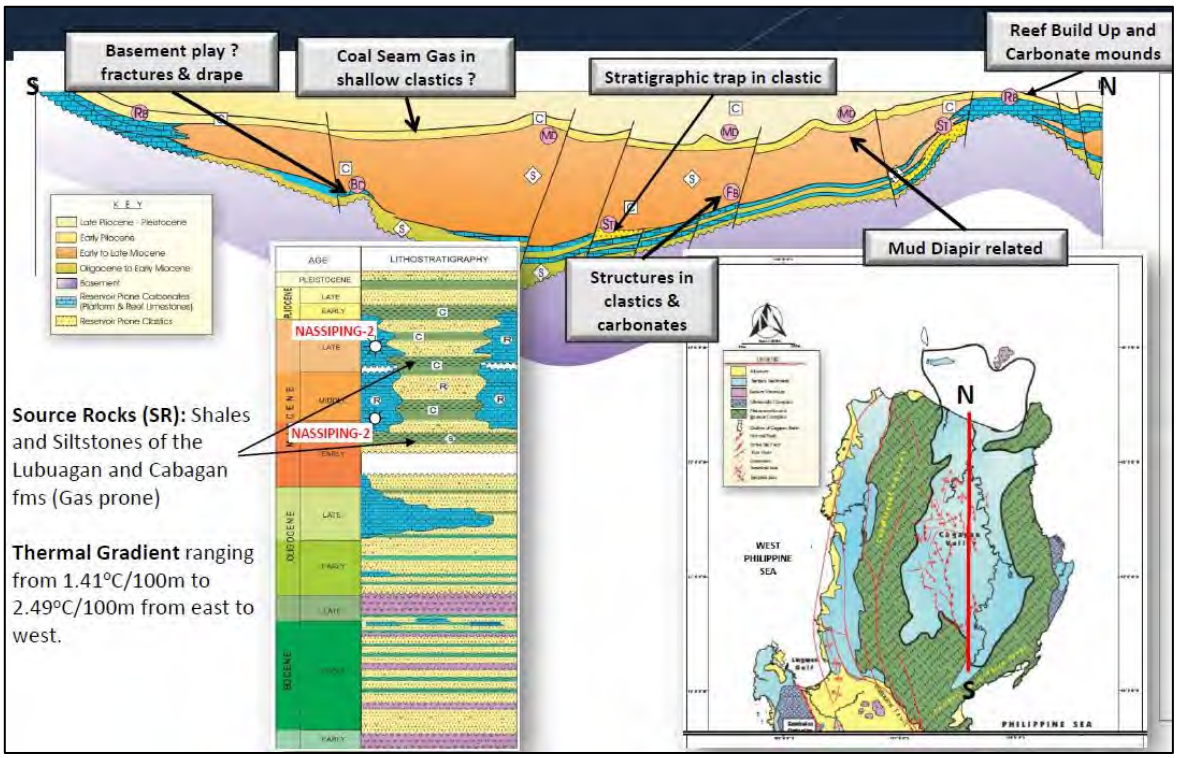

Figure 4-3: Cagayan Basin Plays: Schematic N-S cross-section

Source: Tetragon Energy

The key reservoir types in the basin include:

- Basin margin reefs and carbonate mounds (Ibulao, Sicalao and Callao Limestones): These formations contain carbonate reservoirs formed by reef and carbonate mound structures, known for their high porosity and permeability, making them targets for oil and gas accumulations.
- Structural traps in the Lubuagan Formation (folded and faulted clastic and carbonate facies): Tectonic folding and faulting in the Lubuagan Formation have created structural traps, including anticlines and fault blocks, which serve as traps for hydrocarbon accumulation in both clastic and carbonate facies.
- Fractured basement and basement-drape: Hydrocarbons may accumulate in fractured basement rocks composed of ophiolitic, igneous, and metasedimentary types. The basement-drape play targets hydrocarbons migrating along basement fractures into overlying sedimentary layers.
- Unconventional gas plays in tight limestones, siltstones and shales: The basin centre holds tight limestone, siltstone, and shale formations, which may contain unconventional gas

(shale gas and tight gas). Advances in drilling technologies, such as hydraulic fracturing, can make these plays increasingly viable.

- Coal seam gas (CSG) in the Ilagan Formation and older units: Coal seams in the Ilagan and older formations contain methane, which may be extracted through dewatering and fracking techniques.

These diverse play types make the Cagayan Basin a promising area for future exploration and development, with substantial opportunities for both conventional and unconventional hydrocarbon resources.

4.5 Hydrocarbon Discoveries

4.5.1 San Antonio Gas Field

San Antonio gas field is the closest analogue to the Nassiping discovery and prospect. It is located within Block SC-37 at the southern margin of the Cagayan Basin (Figure 4-1), it is situated on the San Antonio-Ipil structural feature, which comprises a carbonate buildup on the edge of the Sicalao Carbonate Bank. The carbonate platform remained stable from the Oligocene to Late Miocene. The primary reservoir is the Callao Limestone.

The initial discovery occurred with the drilling of Well Ipil-1 in 1958–1959, which tested gas at over 7 MMscf/d. Subsequent drilling in the 1980s led to production from Well San Antonio-1A starting in 1994. The field produced 3.54 Bscf of gas before being shut in 2008. The well produced gas with limited water production.

Other wells such as Well San Antonio-2 were unsuccessful.

The San Antonio gas field is considered an appropriate analogue for the Nassiping discovery and prospects due to its similar tectonic setting (back-arc basin), carbonate reservoir types, and production mechanism. Both Nassiping and San Antonio share marine depositional environments and likely similar quality gas reservoirs.

4.5.2 Nassiping Area

The subsurface structure at the Middle Miocene Callao Limestone is based on two wells Nassiping-1 and Nassiping-2 and four seismic lines (Figure 4-4).

Two DST's recovered gassy water and gas cut mud from the Callao Limestone in Well Nassiping in 1961. In 1984, Well Nassiping-2 located 1,9 km north of Well Nassiping-1, targeted the Middle Miocene Sicalao Limestone, initially interpreted as a reef build-up carbonate with potential reservoir quality. Although numerous gas shows were noted in the Callao Limestone no shows were recorded in the Sicalao Limestone. A re-entry of the well in 2012 flowed low rates of gas and water on test from the Callao Limestone.

The Callao Limestone (2,856 - 3,005 mMD in Well Nassiping-2, represents the upper portion of the Miocene carbonate succession. Deposited in a shallow marine environment, it is composed predominantly of bioclastic limestones exhibiting favourable reservoir characteristics. During drilling the interval flow tested in 2012, light hydrocarbon gases were encountered, indicating hydrocarbon migration and potential entrapment.

The Lubuagan Formation (3,051 – 3,275 mMD) records a transition to a more mixed depositional environment, incorporating fluvial and volcanic influences. It is dominated by shale throughout the interval, with minor interbedded limestone that lacks sufficient porosity and permeability to develop as a reservoir. These units serve as important stratigraphic seals, separating prospective reservoir intervals in overlying and underlying formations.

The Sicalao Limestone (3,275–3,504.5 mMD), has been subdivided into two informal members based on lithofacies and reservoir characteristics: the Upper Reef (3,275–3,390 mMD) and the Lower Platform (3,390–3,504.5 mMD).

This subdivision aligns with volumetric levels A, B and C as follows:

- The Upper Reef, characterised by biohermal buildup and favourable porosity, corresponds to the interval above Sicalao C, and includes the top reservoir section referred to as "Sicalao Upper Reef" in the volumetric analysis.
- The Lower Platform, composed of dense micritic limestone with interbedded shale, spans the Sicalao C–B and B–A intervals. This section exhibits a progressive decline in porosity and reservoir quality and is thus associated with the lower reservoir intervals (Levels B and A).

In summary, the Upper Reef aligns with the main reservoir target (Level C), while the Lower Platform encompasses lower-quality zones evaluated as levels B and A in the volumetrics section.

4.6 Geophysics Overview

The available geophysics data comprise details of 2D seismic data, well data, technical reports, and interpreted data.

4.6.1 Seismic Interpretation

Block SC-82 is covered by 1,523 km of 2D seismic data acquired during the years 1978-1981. The seismic data were digitised and vectorised in the early 2000s. There are five seismic lines near Wells Nassiping-1 and Well Nassiping -2. The seismic data over the Nassiping structure was re-interpreted in 2014 in order to re-map the Callao and Sicalao targets. The re-mapping also included the Lubuagan sandstones that were identified as another possible reservoir in the original drilling of the Well Nassiping-2 (Figure 4-5).

Seven seismic horizons and corresponding grids have been interpreted across the Nassiping-1 and Nassiping-2 wells. Of these, two key horizons, Top Callao and Top Sicalao, were used to generate

both time and depth maps, which were subsequently applied in the volumetric assessment. These maps have been bulk shifted to align the interpreted horizons with the well tops.

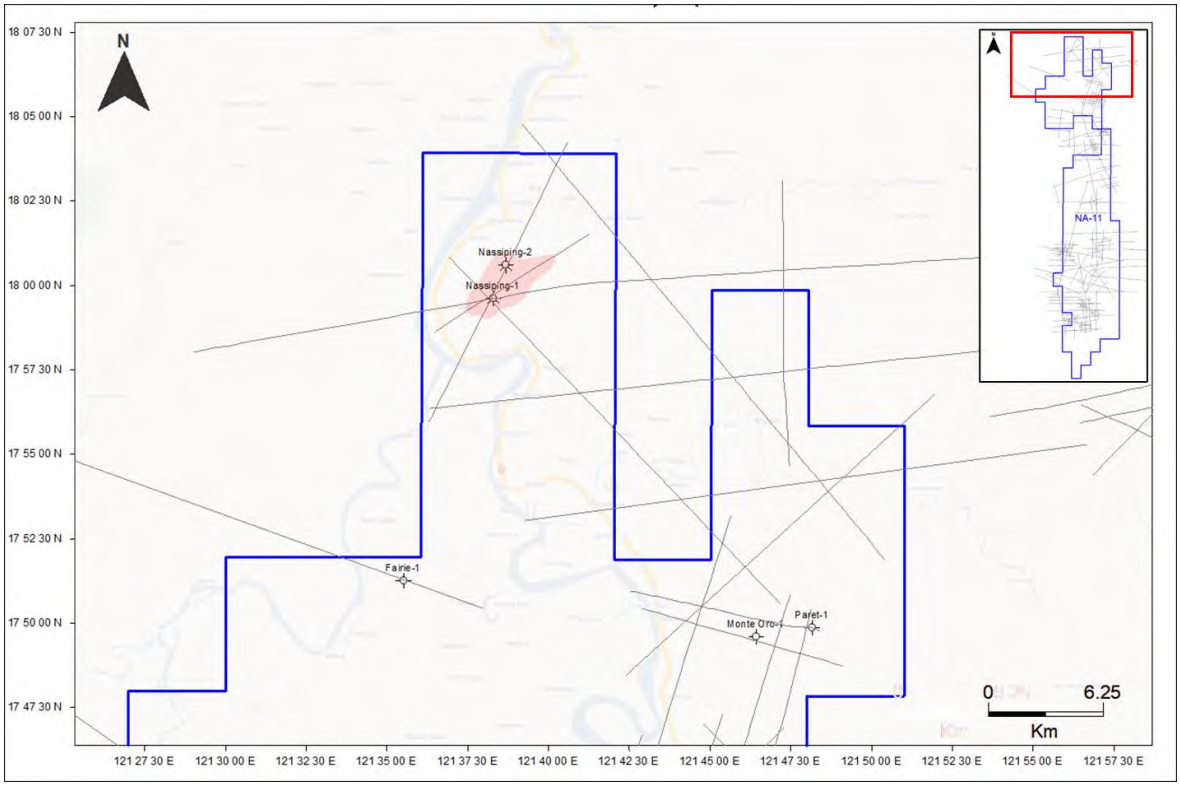

Figure 4-4: Location of the seismic line B-04 crossing the Wells Nassiping-1 and Nassiping-2

Source: Tetragon Energy

The interpretation is based upon only five 2D seismic lines, all of which exhibit poor imaging quality. Notably, only one-line (BA-04) crosses both wells. Sproule ERCE has reviewed the interpretation of these grids in depth and finds them reasonable, given the imaging quality limitations. A seismic line though Wells Nassiping-1 and Nassiping-2 is presented in Figure 4-5.

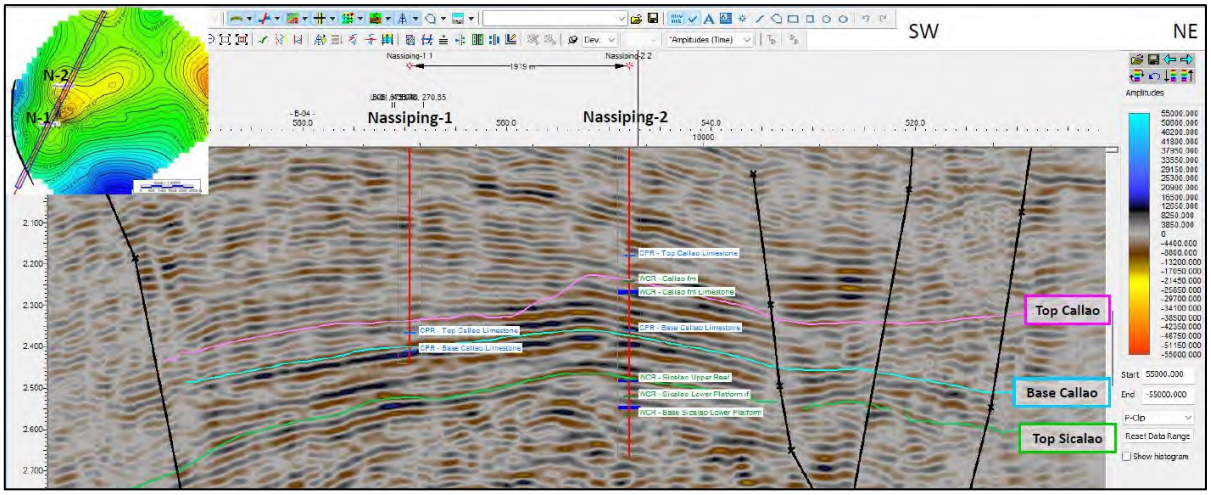

Figure 4-5: Seismic line B-04 intersecting Wells Nassiping-1 and Nassiping-2

Source: Tetragon Energy

The resulting time-structure maps were converted to depth using a polynomial velocity function derived from the velocity survey data acquired in Well Nassiping-2. This function was applied across the interpreted seismic horizons to generate a depth-converted grid (Figure 4-6).

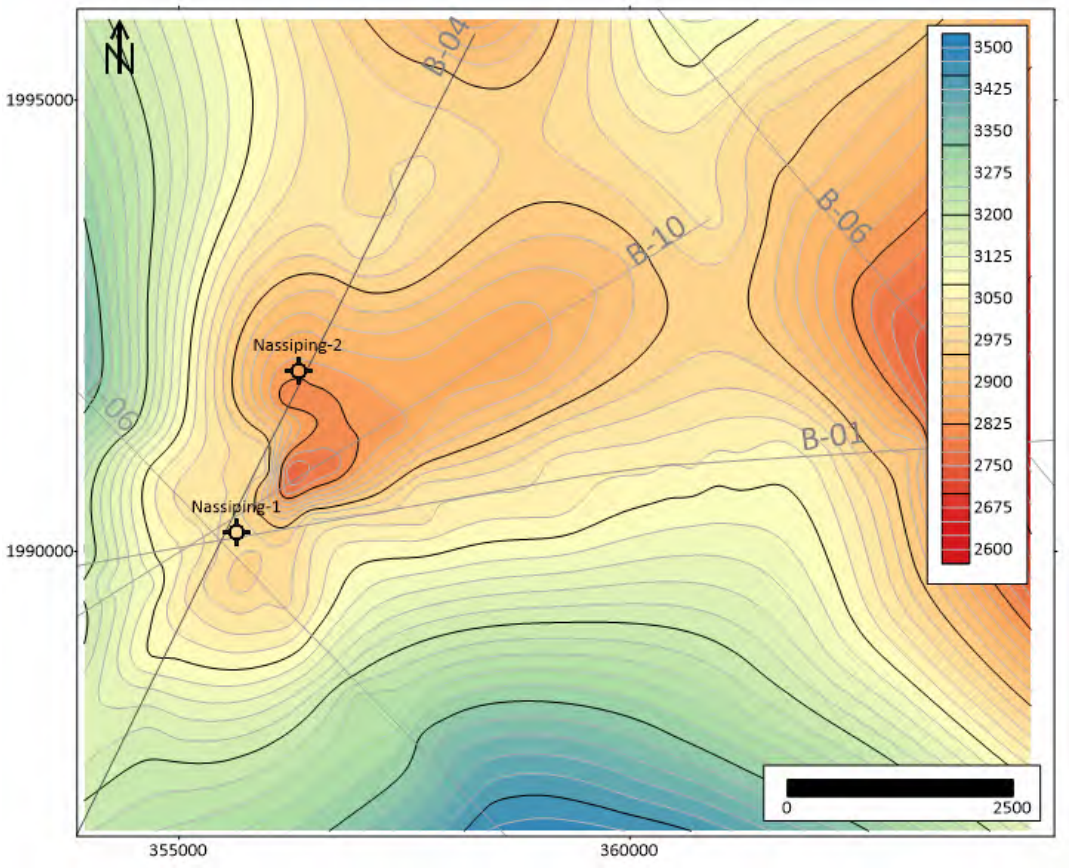

Figure 4-6: Depth conversion result- Callao B depth grid

4.6.2 Petrophysics

Scanned paper log sections for Well Nassiping-2 and an image of the composite log from Well Nassiping-1 were reviewed. Images of cased hole neutron logs of Well Nassiping-2 acquired during the re-entry in 2012 to identify perforation intervals, were also reviewed.

The composite log information for Well Nassiping-1 is useful as a record of the drilling but has limited value for detailed petrophysical analysis

The quality of both open-hole and cased-hole logs in Well Nassiping-2 is poor, with limited vertical resolution and significant noise, which negatively impacts the reliability of log interpretation and saturation calculations. High apparent water saturation values are observed across multiple intervals, resulting in considerable uncertainty in net pay estimates. A qualitative review of the logs confirmed this uncertainty, showing that, within the tested (perforated) intervals of the Callao Limestone, it is not possible to distinguish gas-bearing from water-bearing zones. No gas-water contacts ("GWCs") were identified. These uncertainties have been explicitly considered in the range of estimated in-place and recoverable volumes.

In the light of the log analysis uncertainty, Sproule-ERCE has not prepared an independent petrophysical evaluation. Sproule-ERCE has derived its estimates of input parameters for gas in place calculations based upon a petrophysical interpretation provided by Tetragon Energy, taking into account the uncertainty.

4.7 Reservoir Engineering

The Callao Limestone was tested in Well Nassiping-2 in 2012. Figure 4-7 presents the seven perforated intervals in the Callao A and B between 2856 to 3005 mMD superimposed upon logs showing the gamma ray ("GR") on the left-hand track and the resistivity logs on the right-hand track[2].

The flow rates and pressures recorded during the testing are shown in Figure 4-8. The well was initially flowed for 35 hours to clean up in 18/64" choke. For the majority of the cleanup period the well was flowed whilst bypassing the separator, with no gas rates recorded. In the last hour of cleanup, the well was flowed through a separator, with gas rates of ~110 Mscf/d recorded. Water was noted to be slugging throughout the cleanup period, at rates between ~100 bbl/d and 280 bbl/d.

The well was then shut in for 12 hours, before a multi-rate test was attempted in 12/64" choke. The initial gas flow rate was approximately 500 Mscf/d, declining to less than 50 Mscf/d within a two-hour period, averaging approximately 110 Mscf/d during the measurement, after which the test was abandoned.

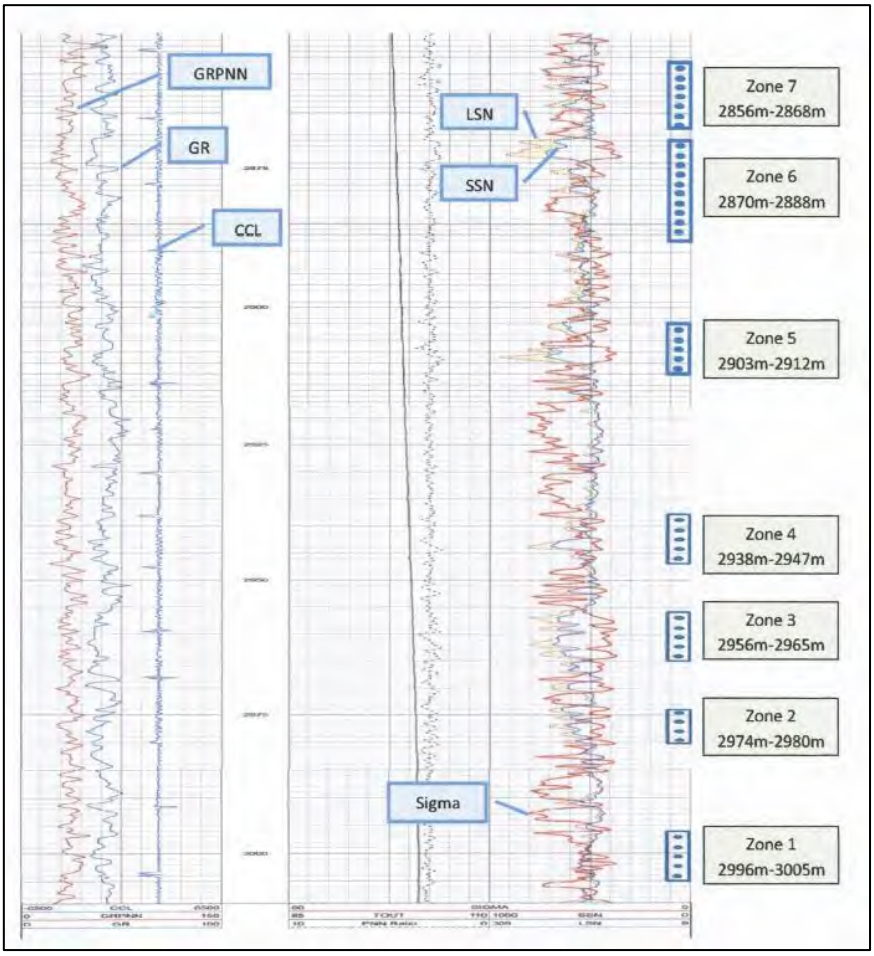

Figure 4-7: Perforated intervals in the Callao A and B

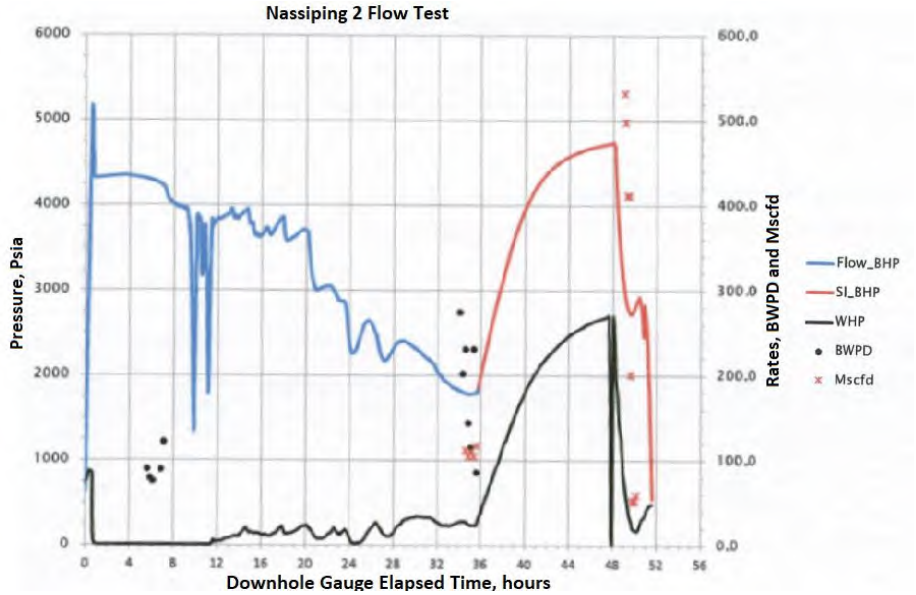

Figure 4-8: Well Nassinping-2 flow test

The initial reservoir pressure of approximately 5100 psi is some 800 psi higher than hydrostatic pressure, indicating the possibility of stacked sands within the Callao Limestone, i.e. the sand intervals are not in vertical pressure communication.

The pressure differential between the WHP and the BHP shown in Figure 4-8 indicates that a column of liquid was present in the wellbore throughout the test. The cumulative water production during the test was 260 bbl. This is significantly higher than the wellbore volume, suggesting that formation water was produced. This is further exemplified as the salinity of the produced water was noted to progressively decrease from 15,000 ppm to 100 ppm. Due to the petrophysical uncertainty, it is not known which of the perforated intervals flowed gas and which flowed water.

No gas samples were taken on test and so the gas composition is unknown.

Sproule ERCE has reviewed an interpretation of the pressure buildup recorded after the cleanup period provided by Tetragon Energy. A permeability thickness of approximately 100 md-ft to water and 5 md-ft to gas is reported, together with a skin factor of +32. In Sproule-ERCE's opinion, reliable interpretation of permeability is compromised by not knowing which interval(s) flowed gas and the impact of water production on the effective permeability of gas.

4.8 Volumetric Analysis

The following section describes the Contingent Resources and Prospective Resources estimated by ERCE in the SC-82 permit area. In addition, a number of exploration leads are identified which will require further work before resources can be assigned.

4.8.1 Estimation of HIIP - Nassiping Area

Sproule ERCE has conducted a probabilistic estimation of the hydrocarbons initially in place (HIIP) and the associated resources for the Callao and Sicalao Limestones in the Nassiping area. Contingent Resources have been assigned to the Callao Limestone, while the Sicalao Limestone has been classified as holding Prospective Resources.

For the purposes of the assessment, the Callao Limestone was subdivided into two units: "Callao B" and "Near Callao A", based on distinct seismic reflectors mapped across the area and calibrated against formation tops in the Nassiping-2 well.

The Sicalao Limestone was divided into three intervals—Above Sicalao C, Between Sicalao C and B, and Between Sicalao B and A—based on regionally mappable seismic reflectors that delineate changes in carbonate facies and platform architecture. These intervals correspond to zones of varying reservoir quality, with the Upper Reef (Above Sicalao C) exhibiting the highest porosity and productivity potential, and the Lower Platform (between Sicalao C–B and B–A) presenting poorer reservoir characteristics.

Petrophysical parameters used in the volumetric calculations were based on Tetragon Energy's interpretation, with a wide range applied to reflect uncertainty. The low-case area for each interval

was defined by the gas-down-to (GDT) level, while the high-case area was set at the mapped structural spill point.

The gas expansion factor ("GEF") was estimated using standard engineering correlations. A broad range of recovery factors was applied: the low case was based on analogues in tight carbonates with an active aquifer, while the high case used the recovery factor reported for the San Antonio field. For the Callao Limestone, the recovery factor was discounted to reflect water production observed during testing, suggesting that one or more of the evaluated intervals may be partially water-bearing.

Sproule ERCE has defined Low, Mid, and High estimates for each of the volumetric input parameters, as discussed in Sections 4.8.1.1 to 4.8.1.5. These parameters were probabilistically combined to derive Low, Mid, and High cases for GIIP, as well as Contingent and Prospective Resources. The COS is addressed in Section 4.8.2

Table 4-2 and Table 4-3 present Sproule ERCE's GIIP and unrisked gas Contingent Resource estimates for the Callao Limestone in the Nassiping discovery. Table 4-4 provides the corresponding GIIP and gas Prospective Resource estimates for Sicalao Limestone.

Table 4-2: Summary of GIIP for Nassiping discovery

	GIIP (Bscf)		
	Low	Mid	High
Nassiping Callao B	2.5	16.7	70.7
Nassiping Near Callao A	12.1	44.0	131.1
Total	**14.7**	**60.7**	**201.8**

Table 4-3: Unrisked Gas Contingent Resources for Nassiping discovery

	Unrisked Gross Contingent Resources (Bscf)			Working Interest (%)	Unrisked Net Contingent Resources to Tetragon Energy (Bscf)		
	1C	2C	3C		1C	2C	3C
Nassiping Callao B	0.5	3.6	19.4	100	0.5	3.6	19.4
Nassiping Near Callao A	2.1	9.7	38.3	100	2.1	9.7	38.3
Total Callao*	**2.6**	**13.3**	**57.7**	**100**	**2.6**	**13.3**	**57.7**

Notes:

1. Tetragon Energy's interest is based on a 100 percent working interest.
2. Totals are added arithmetically, which means statistically, there is a greater than 90% chance of exceeding the Total 1C and less than a 10% chance of exceeding the Total 3C. The aggregated 1C level may be a conservative estimate and the aggregated 3C level may be optimistic due to the portfolio effects of arithmetic summation.
3. Tetragon Energy's net entitlement Contingent Resources requires a full economic evaluation, which has not been done as part of this CPR and hence is not presented.
4. These are unrisked Contingent Resources that have not been risked for chance of development and are sub-classified as Development Unclarified

The Nassiping Contingent Resources are sub-classified as Development Unclarified. The primary contingencies are: poor log quality and ambiguous 2012 flow test results from Well Nassiping-2 preventing reliable petrophysical evaluation; uncertain gas-water contact; unknown gas composition; and no established development concept or commercial framework. Contingent Resources were estimated using a probabilistic volumetric methodology applied to the Callao Limestone, with recovery factors discounted to reflect observed water production. A new well is required to acquire modern logs, core, a comprehensive flow test and fluid samples before commerciality can be assessed. The work programme in Table 4-1 provides for seismic reprocessing and G&G studies (SP1–SP3), well planning (SP4) and the drilling of one well (SP5).

Prospective Resources

Table 4-4: Summary of GIIP and Unrisked Gas Prospective Resources

Reservoir	GIIP (Bscf)			Gross Unrisked Prospective Resources (Bscf)				COS (%)	Gross Risked Mean (Bscf)
	Low	Mid	High	1U	2U	3U	Mean		
Sicalao Upper reef (Above Sicalao C)	1.1	8.4	61.4	0.6	4.7	34.9	15.8	38	6.0
Between Sicalao C and B	1.0	8.6	64.0	0.6	4.8	36.3	16.4	38	6.2
Between Sicalao B and A	1.2	8.7	59.4	0.7	4.9	33.9	15	38	5.7
Total Sicalao*	**3.3**	**25.7**	184.8	1.8	14.4	**105.2**	**47.2**	**38**	**17.9**

Notes:

1. Totals are added arithmetically, which means statistically, there is a greater than 90% chance of exceeding the Total 1U and less than a 10% chance of exceeding the Total 3U. The aggregated 1U level may be a conservative estimate and the aggregated 3U level may be optimistic due to the portfolio effects of arithmetic summation.
2. COS is the chance of geological success.
3. These resources are not risked for chance of development and there is no certainty that if they are discovered they will be developed.

4.8.1.1 Callao B

Figure 4-9 presents the top depth map of the Callao B. The Low area is approximately defined by the "GDT" marker (blue line) in Well Nassiping-2 at 2,864 mMD. The High area is defined by the structural closing (red line) at 2,960 mMD.

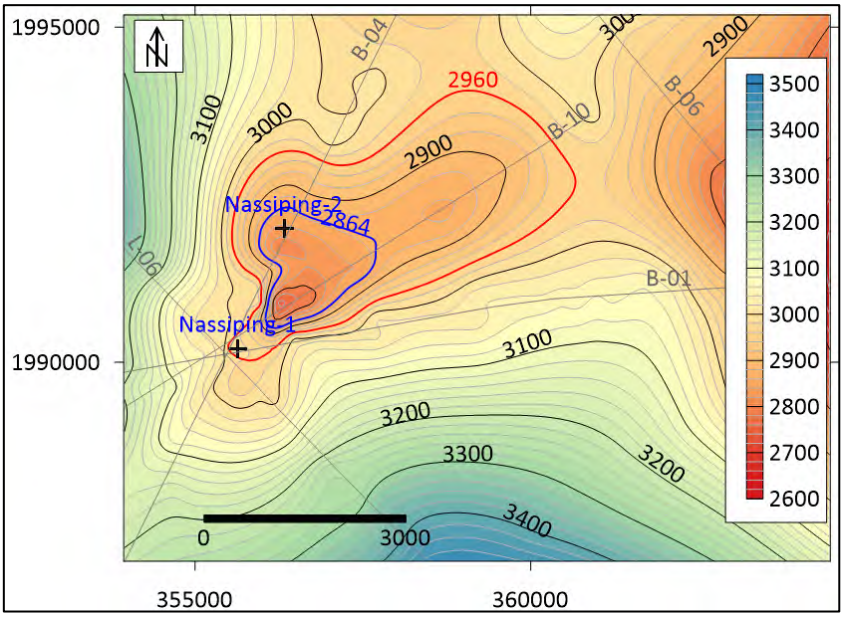

Figure 4-9: Depth map (mMD) for Top Callao B

Figure 4-10 shows seismic line B-04, which illustrates the structural configuration and the stratigraphic interpretation in the Nassiping area. The Callao Limestone Interpretation and the Top Callao B Formation are marked in blue and green respectively, while the top of the Callao A and Base Callao Limestone are shown in yellow and purple. The top of the Sicalao Limestone is also shown in green. The vertical red lines indicate the lateral extent of the closure of the Nassiping structure.

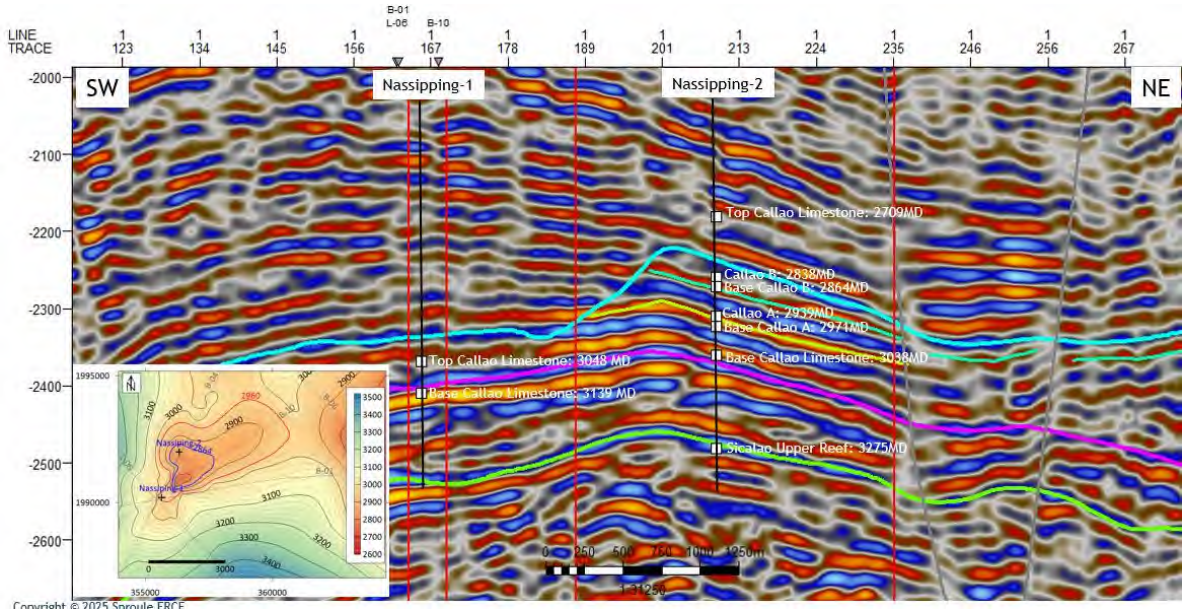

Figure 4-10: Seismic Line B-04 illustrating the interpretated stratigraphic horizons

The input parameters used in the volumetric assessment are summarised in Table 4-5.

Table 4-5: Input parameters for Callao B

	Area (Km²)			Net Pay (m)			Shape Factor (fraction)			Porosity (fraction)			Gas Saturation (fraction)		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
Callao B	2.0	4.7	11.3	1.5	11.3	18.3	0.90	0.92	0.94	0.07	0.15	0.20	0.35	0.50	0.60

	GEF (scf/rcf)			Recovery Factor (fraction)		
	Low	Mid	High	Low	Mid	High
Callao B	250	275	300	0.10	0.22	0.50

4.8.1.2 Near Callao A

Figure 4-11 presents the top depth map of the Near Callao A. The Low area is approximately defined by the “GDT” marker (blue line) in Well Nassiping-2 at 2,971 mMD. The High area is defined by the structural closing (red line) at 3,060 mMD.

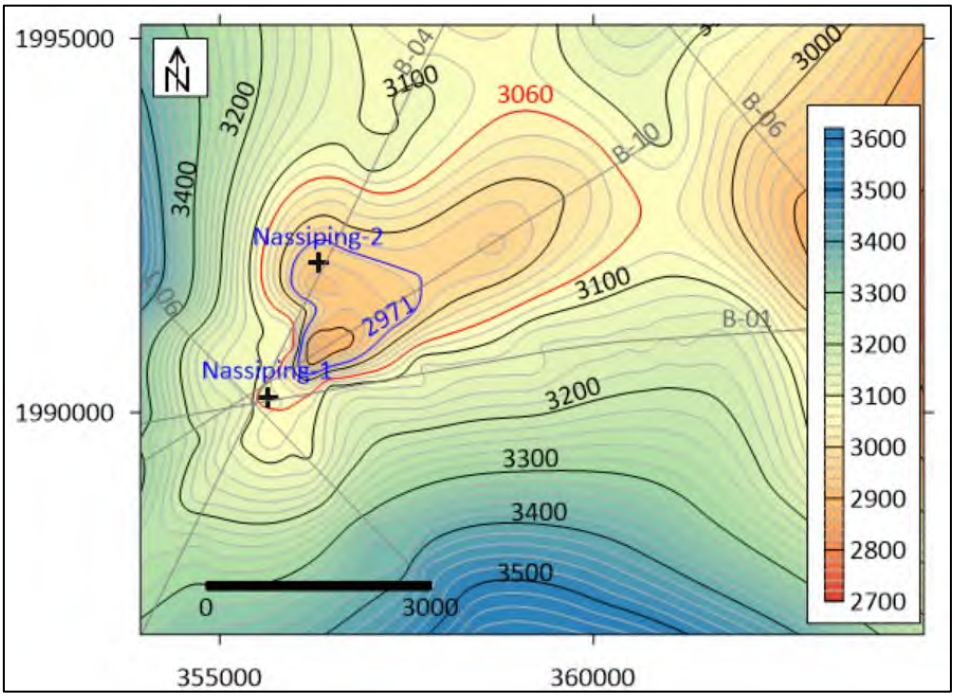

Figure 4-11: Depth map (mMD) Near Callao A

The input parameters used in the volumetric assessment are summarised in Table 4-6.

Table 4-6: Input parameters for Near Callao A

	Area (Km²)			Net Pay (m)			Shape Factor (fraction)			Porosity (fraction)			Gas Saturation (fraction)		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
Near Callao A	3.0	5.7	11.2	6.1	18.3	27.4	0.90	0.92	0.94	0.07	0.13	0.20	0.35	0.50	0.60

	GEF (scf/rcf)			Recovery Factor (fraction)		
	Low	Mid	High	Low	Mid	High
Near Callao A	255	280	305	0.10	0.22	0.50

4.8.1.3 Sicalao Upper Reef (Above Sicalao C)

Figure 4-12 presents the top depth map of the Sicalao Upper Reef (Above C). The Low area is approximately defined by the "GDT" marker (blue line) in Well Nassiping-2 at 3,284 mMD. The High area is defined by the structural closing (red line) at 3,405 mMD.

Seismic line B-04 in Figure 4-13 shows the picks of the Upper Sicalao Reef (Above Sicalao C), between C-B and Sicalao between B-A in green, orange and yellow respectively.

The input parameters used in the volumetric assessment are summarised in Table 4-7.

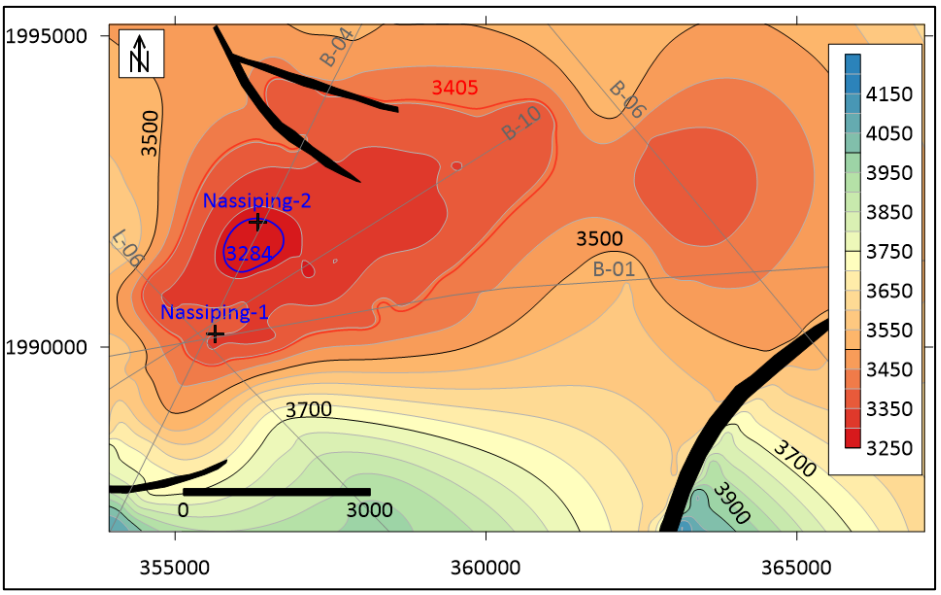

Figure 4-12: Depth map (mMD) of the Sicalao Upper Reef (above Sicalao C)

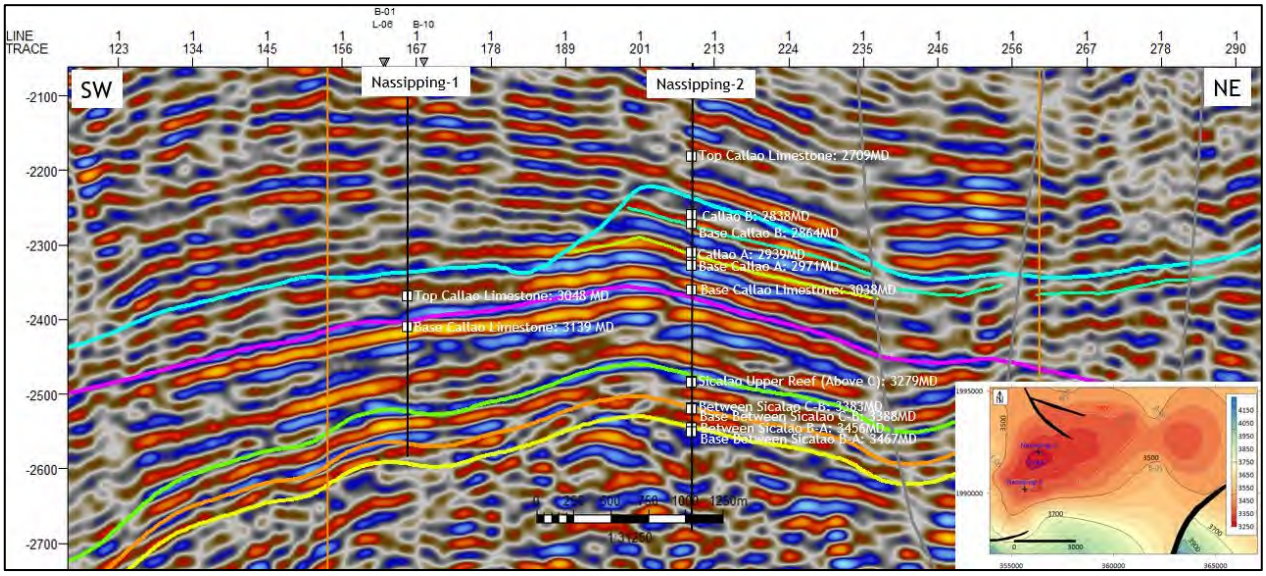

Figure 4-13: Seismic line B-04 illustrating the interpretated stratigraphic horizons

Table 4-7: Input parameters for Upper Sicalao Reef (above Sicalao C)

	Area (Km²)			Net Pay (m)			Shape Factor (fraction)			Porosity (fraction)			Gas Saturation (fraction)		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
(Above Sicalao C)	0.6	3.4	18.9	1.5	4.6	7.6	0.95	0.97	0.99	0.05	0.11	0.17	0.60	0.72	0.85

	GEF (scf/rcf)			Recovery Factor (fraction)		
	Low	Mid	High	Low	Mid	High
(Above Sicalao C)	265	290	315	0.45	0.56	0.70

4.8.1.4 Between Sicalao C and B

Figure 4-14 presents the top depth map of the Between Sicalao C and B horizon marker. The Low area is approximately defined by the “GDT” marker (blue line) in Well Nassiping-2 at 3,388 mMD. The High area is defined by the structural closure (red line) at 3,510 mMD.

The input parameters used in the volumetric assessment are summarised in Table 4-8.

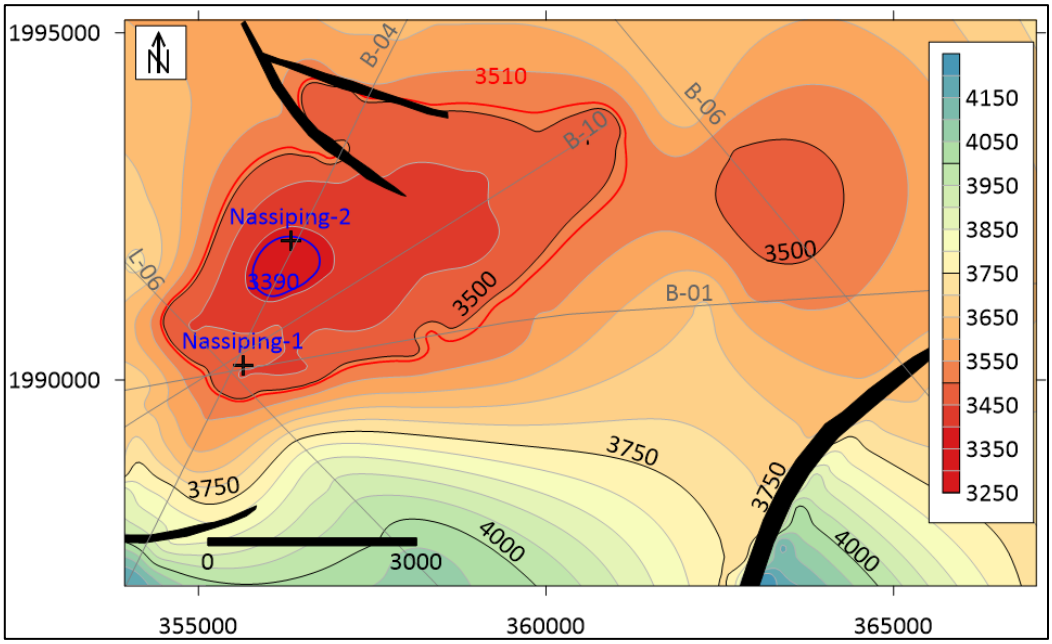

Figure 4-14: Depth map (mMD) between Sicalao C and B Depth Map, showing the GDT (blue line) and structural

Table 4-8: Inputs parameters between Sicalao C and B

	Area (Km²)			Net Pay (m)			Shape Factor (fraction)			Porosity (fraction)			Gas Saturation (fraction)		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
Between Sicalao C and B	0.6	3.4	19.0	1.5	6.1	9.1	0.95	0.97	0.99	0.05	0.11	0.17	0.50	0.65	0.80

	GEF (scf/rcf)			Recovery Factor (fraction)		
	Low	Mid	High	Low	Mid	High
Between Sicalao C and B	275	295	315	0.45	0.56	0.70

4.8.1.5 Between Sicalao B and A

Figure 4-15 presents the top depth map of the Between Sicalao B and A horizon marker. The Low area is approximately defined by the “GDT” marker (blue line) in Well Nassiping-2 at 3,467 mMD. The High area is defined by the structural closing (red line) at 3,585 mMD.

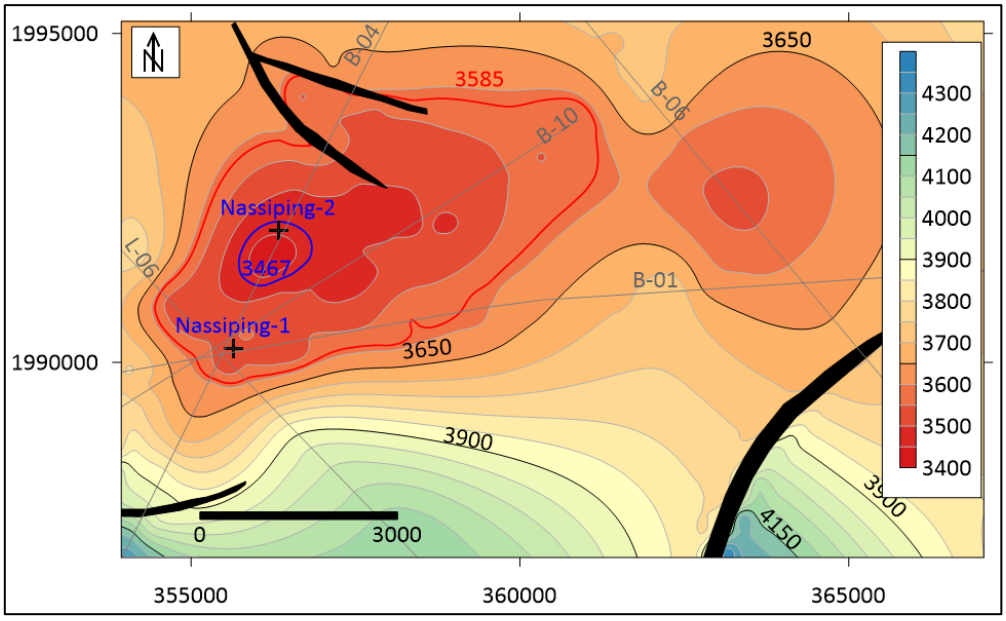

Figure 4-15: Depth map (mMD) between Sicalao B and A

The input parameters used in the volumetric assessment are summarised in Table 4-9.

Table 4-9: Inputs parameters between Sicalao B and A

	Area (Km²)			Net Pay (m)			Shape Factor (fraction)			Porosity (fraction)			Gas Saturation (fraction)		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
Between Sicalao B and A	0.8	3.9	19.4	1.5	6.1	9.1	0.95	0.97	0.99	0.04	0.07	0.14	0.60	0.70	0.80

	GEF (scf/rcf)			Recovery Factor (fraction)		
	Low	Mid	High	Low	Mid	High
Between Sicalao B and A	260	295	335	0.45	0.56	0.70

4.8.2 Risk (Chance of Success) - Cagayan Basin

Sproule-ERCE has used a standard industry approach to assess the geological chance of success for the Sicalao Limestone prospect that was encountered in Well Nassiping-2.

The Sicalao prospect has been assigned a source confidence rating of 100%, based on regional petroleum system indicators such as gas shows in Well Nassiping-2 and oil seeps elsewhere in the basin. Sproule-ERCE assigned 70% confidence for the trap risk based on seismic interpretation and taking into account the data quality and well control. Reservoir quality carries higher uncertainty, with a 60% risk, due to likely low effective porosity and limited validation. Seal confidence is rated at 90%,

supported by overlying clay-rich shales that have demonstrated effective sealing elsewhere in the basin. Table 4-10 presents the resulting geological chance of success (COS) of 38%.

Table 4-10: Evaluation risk for Sicalao prospect

Prospect	Source	Trap	Reservoir	Seal	COS
Sicalao	100%	70%	60%	90%	**38%**

4.9 Leads

Based on the interpretation of the available 2D seismic data, five leads have been delineated by Tetragon Energy. These leads indicate exploration potential across both carbonate and clastic intervals and are predominantly gas-prone. The mapped leads are illustrated in Figure 4-16.

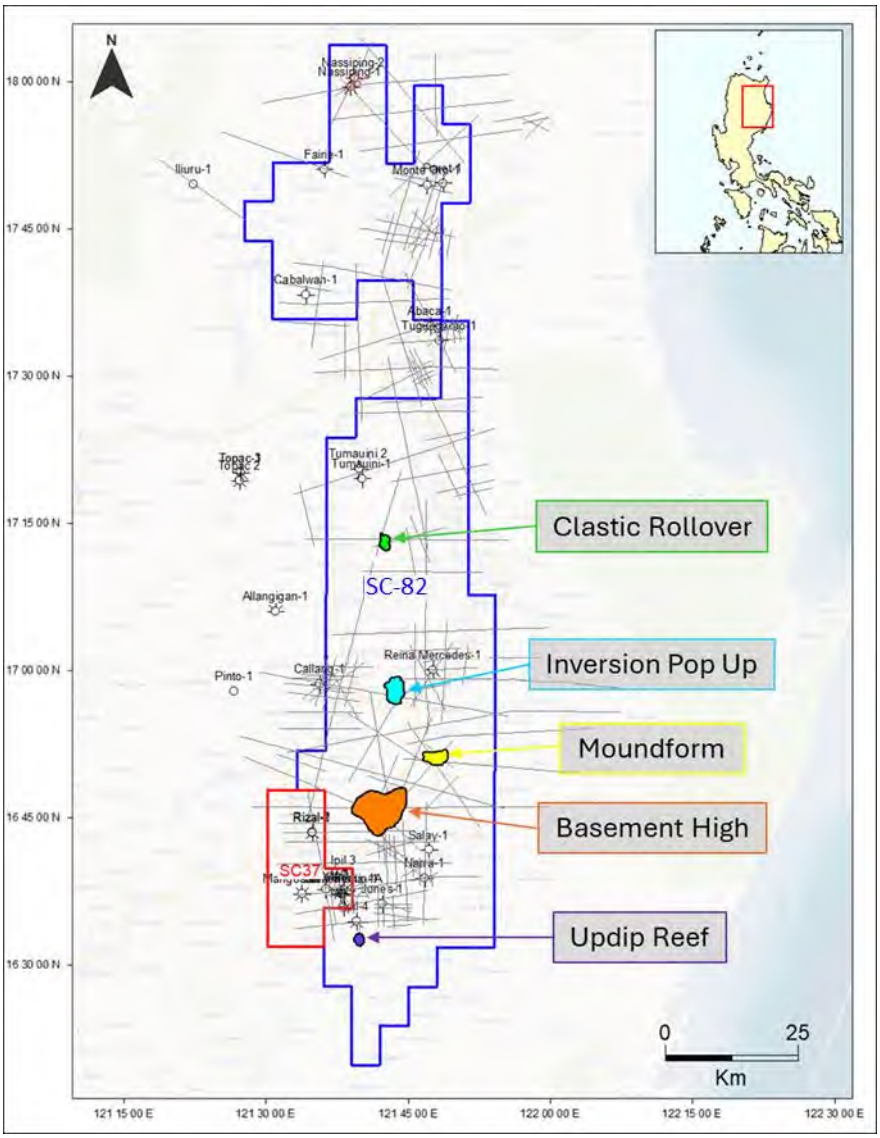

Figure 4-16: Leads identified within Block SC-82

Source: Tetragon Energy

The SC-82 area is currently covered solely by 2D seismic data, which contributes to geological uncertainty. Consequently, these features have been classified as leads, rather than mature prospects. This classification reflects their early-stage status and the need for further de-risking through additional seismic acquisition (ideally 3D), structural mapping, and geological analysis to validate their potential and potentially elevate them to prospect status.

The primary potential traps are comprised of reef deposits located within the Callao and Sicalao Limestones, as well as structural closures within platform carbonates and clastic formations, with particular emphasis on the Lubuagan Formation. Additionally, a Basement play has been identified in the southern region of the block.

To date, gas has been the dominant hydrocarbon phase encountered in the wells, and the abundance of gas-prone source rocks further supports the estimation of resource volumes focused on dry gas. While minor oil shows have been observed in certain wells, and there is evidence of oil seeps at the surface, it is important to note that oil potential should not be entirely dismissed.

A total of five leads has been mapped by Tetragon Energy within Block SC-82, as listed in Table 4-11.

Table 4-11: Leads in Block SC-82

Lead	Type	Age	2D Line	Area (Km²)
1	Clastic Rollover	Lubuagan	L-10	16.7
2	Updip Reef	Lubuagan	N-03EXT	3.3
3	Inversion Pop Up	Lubuagan	L-14	13.9
4	Moundform	Callao	L-24	10.1
5	Basement High	Eocene?	R-01, R-01Ext	60.8

4.9.1.1 Clastic Rollover

Clastic Rollover is a lead withing the Lubuagan Sandstone formation, located in the central part of the Block SC-82, as identified on the interpretation of 2D seismic line L10. The lead is interpreted by three 2D seismic lines: L-10, T-07Ext and L-27, which have enabled a preliminary assessment of its geometry and structural setting.

Figure 4-17 presents the seismic lines that cross the Clastic Rollover lead, along with the outline of the interpreted lead area (in red), superimposed on a time-structure map of the top Lubuagan Sandstone. The estimated areal extent is approximately 16.7 km². The currently available seismic data does not demonstrate a clearly defined structural closure or valid trapping mechanism.

Well Tumauini-1, is located approximately 10 km to the northwest of the lead. While it provides useful regional geological information, its distance limits direct correlation with the lead's structural configuration.

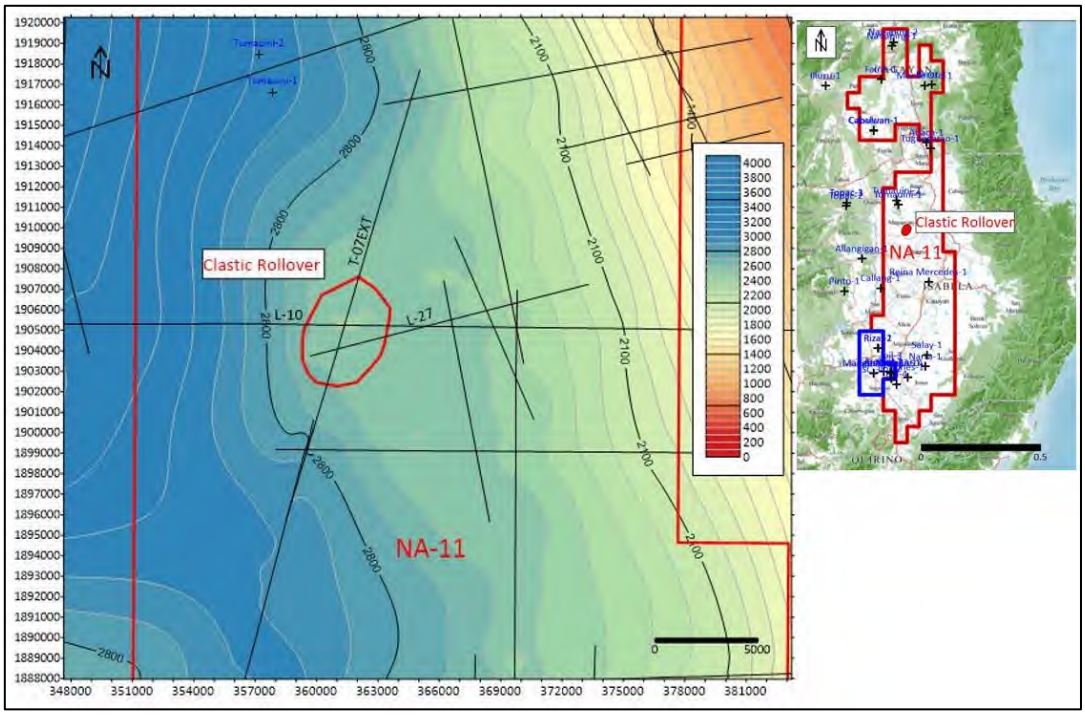

Figure 4-17: Time- structure map showing the extend of Clastic Rollover lead

4.9.1.2 Updip Reef

Well Ipil-4 was drilled in 1959 and encountered more than 900 meters of Middle Miocene carbonate sediments exhibiting hydrocarbon shows. However, no commercial accumulations were confirmed. Subsequent interpretation of available seismic data suggests that the well was likely drilled off the main structural closure. A potential up-dip closure to the south has been identified, which may represent a more favourable location for hydrocarbon entrapment and merits further evaluation.

Figure 4-18 presents a polygon delineated on 2D seismic lines (N-03EXT), defining the areal extent of the Updip Reef lead, located within the Lubuagan Sandstone Formation in the southern part of the basin, near Well Ipil-4. The estimated areal extent is approximately 3.3 km².

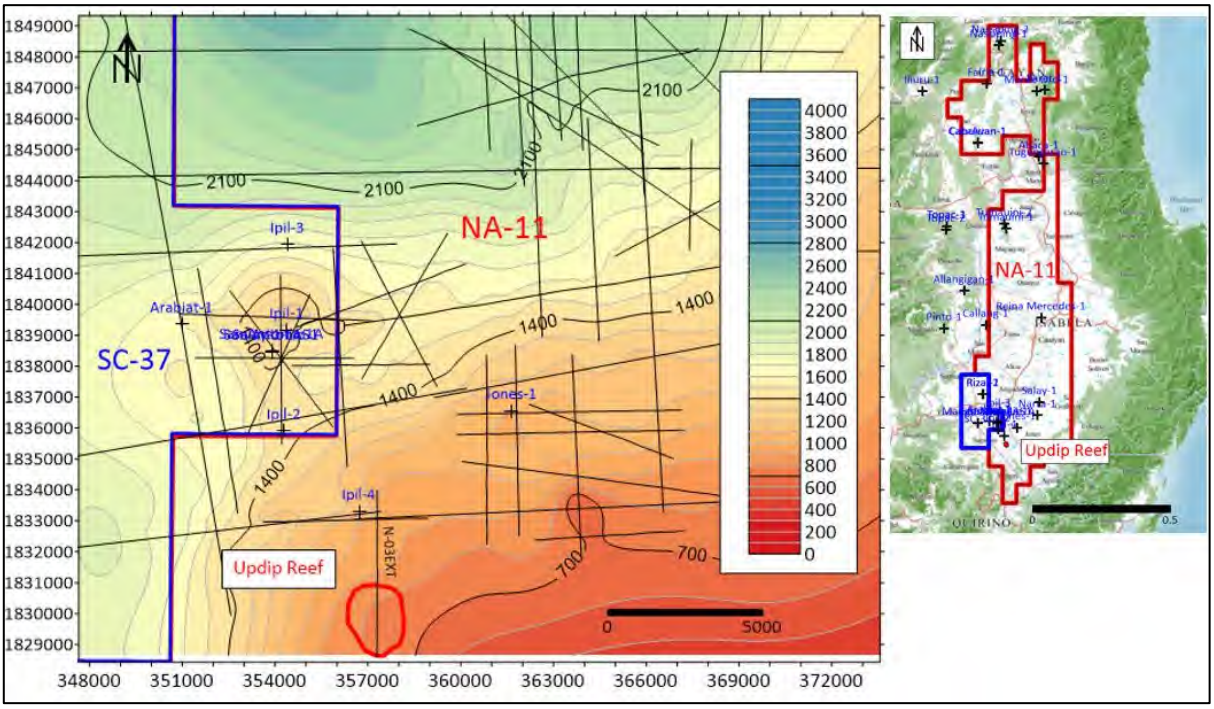

Figure 4-18: Time- structure map showing the extent of the Updip Reef lead.

4.9.1.3 Clastic fault-bounded Inversion ("Pop-up") structure

A fault-bounded structural closure has been identified to the southwest of Well Reina Mercedes-1, along 2D seismic line L-14. The feature is interpreted as a structural inversion or "pop-up" structure, likely formed through compressional reactivation of pre-existing extensional faults.

The lead is intersected by three 2D seismic lines: L-23, L-14, and A-09, which provide sufficient data to define the preliminary geometry. The nearest well, Reina Mercedes-1, is located approximately 6 km to the northeast of the lead area and offers useful regional geological context.

Figure 4-19 presents a polygon delineated using 2D seismic lines, indicating the areal extent of the lead. The reservoirs within this lead are expected to consist of sandstones and siltstones of the Lubuagan Formation. The estimated areal extent is approximately 13.9 km².

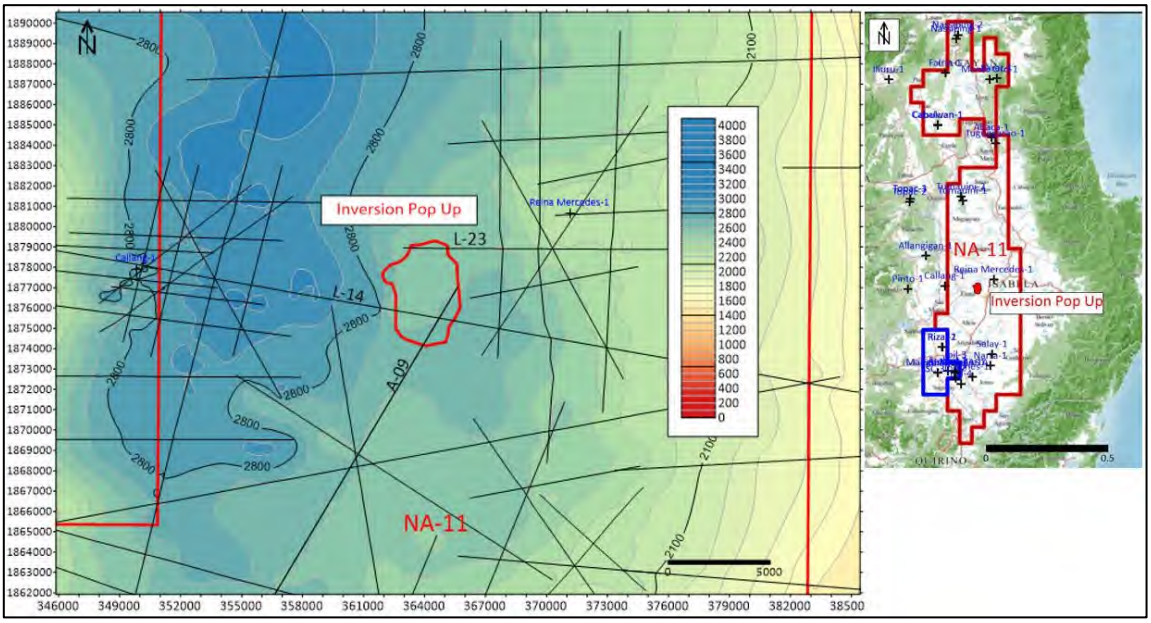

Figure 4-19: Time- structure map showing the extent of the Pop-up lead.

4.9.1.4 Moundform

A Moundform has been identified to approximately 11 km to the southwest of Well Reina Mercedes-1, and north of the Well Salay-1. This feature is evident on four seismic lines (A-06, A-02EXT, L-22, L-24). The lead is characterised as a fault-bounded inversion structure.

Figure 4-20 presents an amplitude map over the lead, along with a polygon indicating its approximate areal extent of 10.1 km².

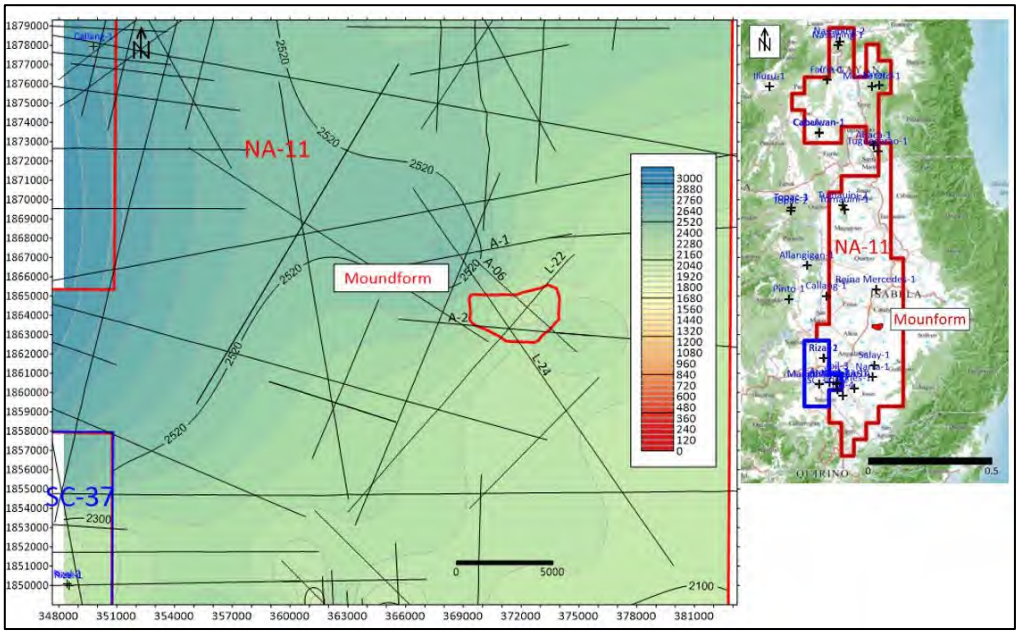

Figure 4-20: Time- structure map showing the extent of the Moundform lead

4.9.1.5 Basement High

A prominent Basement structure has been mapped on eight seismic lines (R-01, R-01EXT, R-22, R-02, L-22, L-16, T-6 and A-07) in the southern part of the basin, between the San Antonio field and Well Salay-1. Although the top of the structure lies at around 4,570 m, there remains potential for hydrocarbon accumulation within an erosional sediment drape combined with a fractured basement. The surrounding basin, containing possible Oligocene to Early Miocene deposits, likely hosts mature source rocks, making hydrocarbon migration into the fractured basement and overlying sedimentary drape a plausible scenario.

Figure 4-21 presents an amplitude map over the lead, along with a polygon indicating its approximate areal extent of 60.8 km².

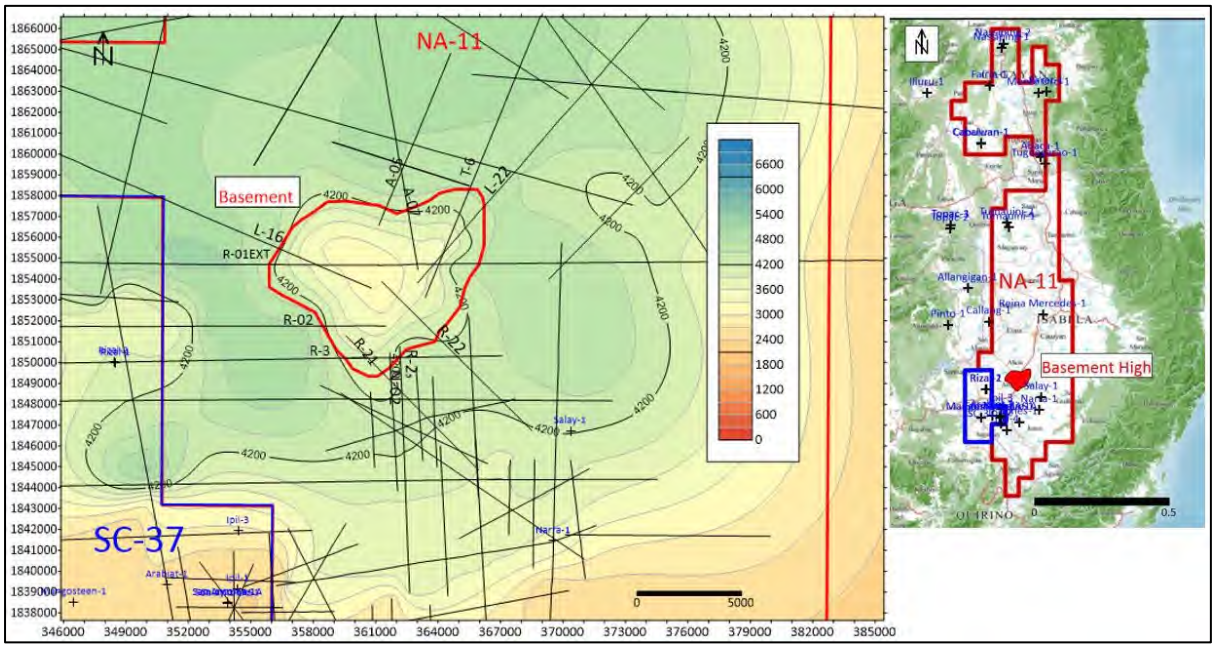

Figure 4-21: Time- structure map showing the extent of the Basement High lead

Appendix 1: SPE PRMS Guidelines

This report references the SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE Petroleum Reserves and Resources Classification System and Definitions, as revised in June 2018 (PRMS). The full text of the PRMS document can be viewed at:

https://www.spe.org/en/industry/petroleum-resources-management-system-2018/

Definitions of the key PRMS Reserves and resources classes, categories and a glossary of related terms can be found at the above address.

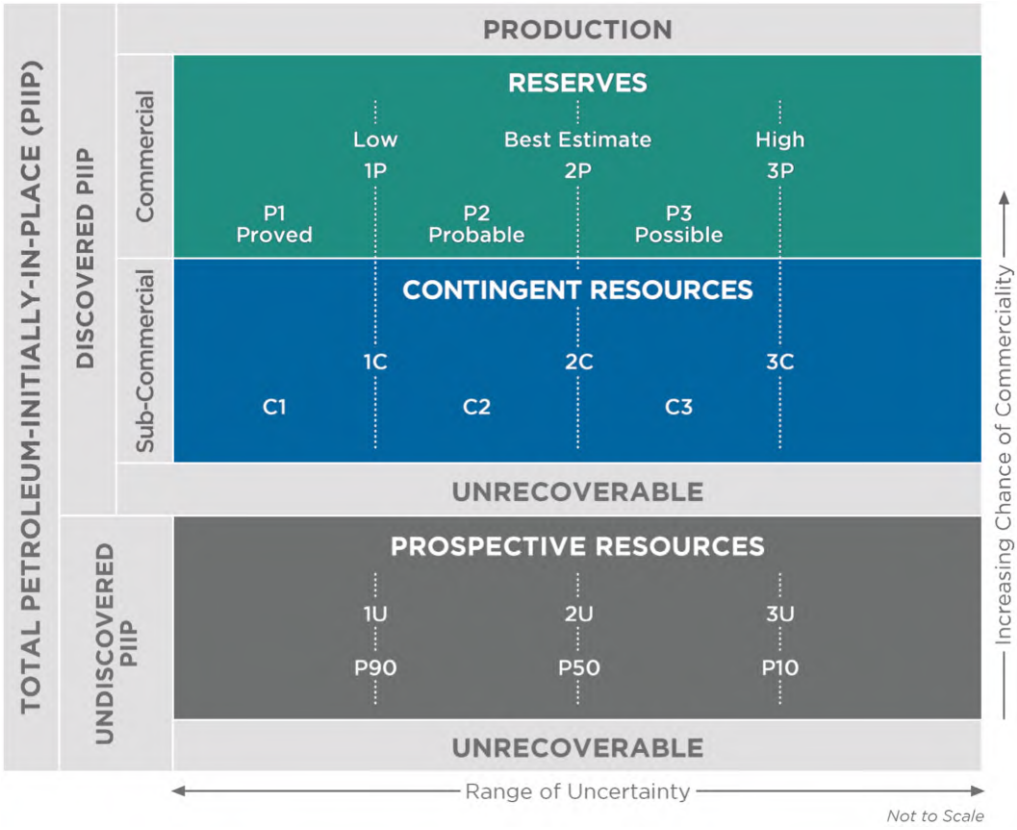

Figure A: PRMS Resources classification framework

(Modified from Petroleum Resources Management System (PRMS) Revised June 2018, page 8, Figure 1.1)

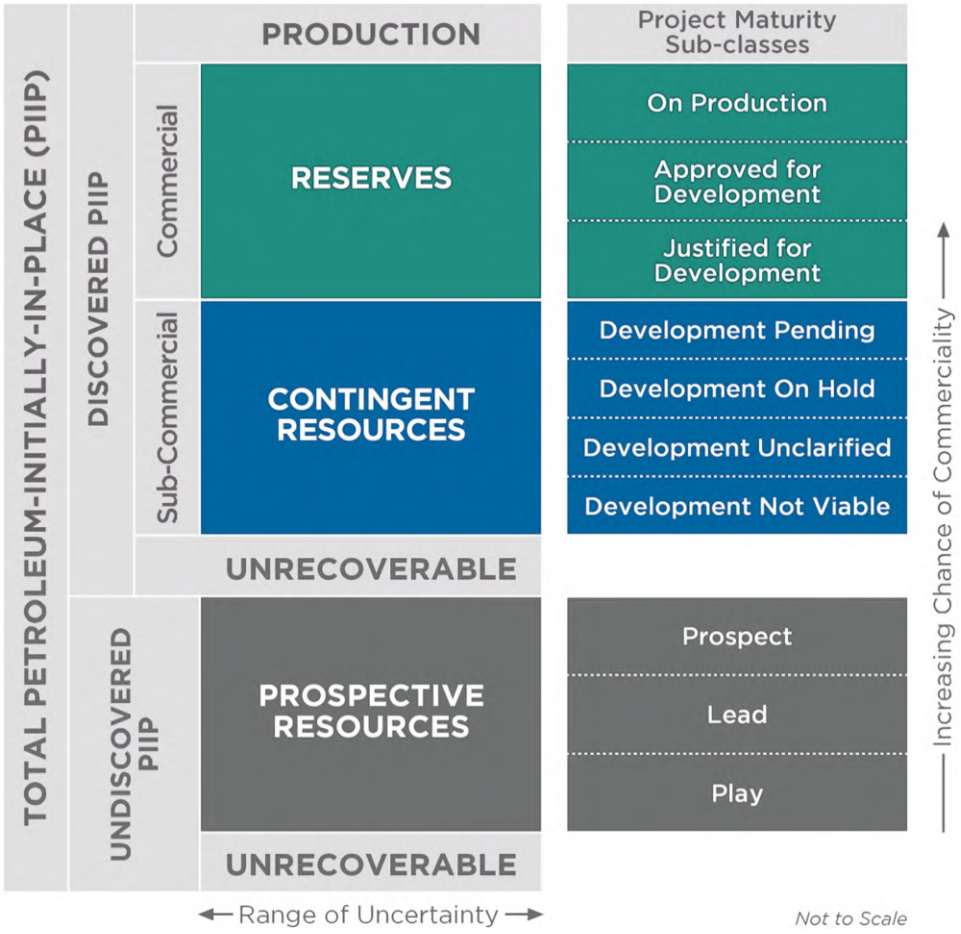

Figure B: PRMS Resources sub-classes

(Modified from Petroleum Resources Management System (PRMS) Revised June 2018, page 8, Figure 2.1)

Table 1: PRMS Recoverable Resources Classes and Sub-Classes

Classes/Sub-classes	Definition	Guidelines
Reserves	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 based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that there is 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, for example, development of an economic project is deferred at the option of the producer for, among other things, market-related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

Classes/Sub-classes	Definition	Guidelines
On Production	The development project is currently producing or capable of producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame}) There must be no known contingencies that could preclude the development from proceeding (see Reserves class). The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.

Classes/Sub-classes	Definition	Guidelines
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub- classified based on project maturity and/or characterised by the economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.

Classes/Sub-classes	Definition	Guidelines
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status. The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.

Classes/Sub-classes	Definition	Guidelines
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2: PRMS Reserves Status Definitions and Guidelines

Status	Definition	Guidelines
Developed Reserves	Expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-producing.
Developed Producing Reserves	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.	Improved recovery Reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.	Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3: PRMS Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations.	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 (P90) that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and 2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved. Reserves in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Those additional Reserves that analysis of geoscience and engineering data indicates 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. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Possible Reserves	Those additional reserves that analysis of geoscience and engineering data indicates 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), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of economic production from the reservoir by a defined, commercially mature project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	See above for separate criteria for Probable Reserves and Possible Reserves.	The 2P and 3P estimates may be based on reasonable alternative technical interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing faults until this reservoir is penetrated and evaluated as commercially mature and economically productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

Table 4: Glossary of Terms Used in PRMS Referred to in this Report

Term	Definition
1C	Denotes low estimate of Contingent Resources.
2C	Denotes best estimate of Contingent Resources.
3C	Denotes high estimate of Contingent Resources.
1U	Denotes the unrisked low estimate qualifying as Prospective Resources.
2U	Denotes the unrisked best estimate qualifying as Prospective Resources.
3U	Denotes the unrisked high estimate qualifying as Prospective Resources.
Accumulation	An individual body of naturally occurring petroleum in a reservoir.
Aggregation	The process of summing well, reservoir, or project-level estimates of resources quantities to higher levels or combinations, such as field, country or company totals. Arithmetic summation of incremental categories may yield different results from probabilistic aggregation of distributions.
Appraisal	The phase that may follow successful exploratory drilling. Activities to further evaluate the discovery, such as seismic acquisition, geological studies, and drilling additional wells may be conducted to reduce technical uncertainties and commercial contingencies.
Analog	Method used in resources estimation in the exploration and early development stages (including improved recovery projects) when direct measurement is limited. Based on evaluator's assessment of similarities of the analogous reservoir(s) together with the development plan.
Analogous Reservoir	Reservoirs that have similar rock properties (e.g., petrophysical, lithological, depositional, diagenetic, and structural), fluid properties (e.g., type, composition, density, and viscosity), reservoir conditions (e.g., depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide insight and comparative data to assist in estimation of recoverable resources.
Assessment	See Evaluation.
Associated Gas	A natural gas found in contact with or dissolved in crude oil in the reservoir. It can be further categorized as gas cap gas or solution gas.
Barrel of Oil Equivalent (BOE)	The term allows for a single value to represent the sum of all the hydrocarbon products that are forecast as resources. Typically, condensate, oil, bitumen, and synthetic crude barrels are taken to be equal (1 bbl = 1 BOE). Gas and NGL quantities are converted to an oil equivalent based on a conversion factor that is recommended to be based on a nominal heating content or calorific value equivalent to a barrel of oil.

Basis for Estimate	The methodology (or methodologies) and supporting data on which the estimated quantities are based. (Also referenced as basis for the estimation.)
Best Estimate	With respect to resources categorization, the most realistic assessment of recoverable quantities if only a single result were reported. If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
C1	Denotes low estimate of Contingent Resources. C1 is equal to 1C.
C2	Denotes Contingent Resources of same technical confidence as Probable, but not commercially matured to Reserves.
C3	Denotes Contingent Resources of same technical confidence as Possible, but not commercially matured to Reserves.
Chance	Chance equals 1-risk. Generally synonymous with likelihood. (See Risk)
Chance of Commerciality	The estimated probability that the project will achieve commercial maturity to be developed. For Prospective Resources, this is the product of the chance of geologic discovery and the chance of development. For Contingent Resources and Reserves, it is equal to the chance of development.
Chance of Development	The estimated probability that a known accumulation, once discovered, will be commercially developed.
Chance of Geologic Discovery	The estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum.
Commercial	A project is commercial when there is evidence of a firm intention to proceed with development within a reasonable time-frame. Typically, this requires that the best estimate case meet or exceed the minimum evaluation decision criteria (e.g., rate of return, investment payout time). There must be a reasonable expectation that all required internal and external approvals will be forthcoming. Also, there must be evidence of a technically mature, feasible development plan and the essential social, environmental, economic, political, legal, regulatory, decision criteria, and contractual conditions are met. .
Completion	Completion of a well. The process by which a well is brought to its operating status (e.g., producer, injector, or monitor well). A well deemed to be capable of producing petroleum, or used as an injector, is completed by establishing a connection between the reservoir(s) and the surface so that fluids can be produced from, or injected into, the reservoir.
Completion Interval	The specific reservoir interval(s) that is (are) open to the borehole and connected to the surface facilities for production or injection, or reservoir intervals open to the wellbore and each other for injection purposes.

Concession	A grant of access for a defined area and time period that transfers certain entitlements to produced hydrocarbons from the host country to an entity. The entity is generally responsible for exploration, development, production, and sale of hydrocarbons that may be discovered. Typically granted under a legislated fiscal system where the host country collects taxes, fees, and sometimes royalty on profits earned. (Also called a license.)
Condensate	A mixture of hydrocarbons (mainly pentanes and heavier) that exist in the gaseous phase at original temperature and pressure of the reservoir, but when produced, are in the liquid phase at surface pressure and temperature conditions. Condensate differs from NGLs in two respects: (1) NGL is extracted and recovered in gas plants rather than lease separators or other lease facilities, and (2) NGL includes very light hydrocarbons (ethane, propane, or butanes) as well as the pentanes-plus that are the main constituents of condensate.
Confidence Level	A measure of the estimated reliability of a result. As used in the deterministic incremental method, the evaluator assigns a relative level of confidence (high/moderate/low) to areas/segments of an accumulation based on the information available (e.g., well control and seismic coverage). Probabilistic and statistical methods use the 90% (P90) for the high confidence (low value case), 50% (P50) for the best estimate (moderate value case), and 10% (P10) for the low (high value case) estimate to represent the chances that the actual value will equal or exceed the estimate.
Contingency	A condition that must be satisfied for a project in Contingent Resources to be reclassified as Reserves. Resolution of contingencies for projects in Development Pending is expected to be achieved within a reasonable time period.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.
Conventional Resources	Resources that exist in porous and permeable rock with buoyancy pressure equilibrium. The PIIP is trapped in discrete accumulations related to a localized geological structural feature and/or stratigraphic condition, typically with each accumulation bounded by a down dip contact with an aquifer and is significantly affected by hydrodynamic influences such as buoyancy of petroleum in water.
Cost Recovery	Under a typical production-sharing agreement, the contractor is responsible for the field development and all exploration and development expenses. In return, the contractor recovers costs (investments and operating expenses) out of the production stream. The contractor normally receives an entitlement interest share in the petroleum production and is exposed to both technical and market risks.

Crude Oil	Crude oil is the portion of petroleum that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric conditions of pressure and temperature (excludes retrograde condensate). Crude oil may include small amounts of non-hydrocarbons produced with the liquids but does not include liquids obtained from the processing of natural gas.
Defined Conditions	Forecast of conditions to exist and impact the project during the time period being evaluated. Forecasts should account for issues that impact the commerciality, such as economics (e.g., hurdle rates and commodity price); operating and capital costs; and technical, marketing, sales route, legal, environmental, social, and governmental factors.
Deposit	Material laid down by a natural process. In resources evaluations, it identifies an accumulation of hydrocarbons in a reservoir. (See Accumulation.)
Deterministic Method	An assessment method based on discrete estimate(s) made based on available geoscience, engineering, and economic data and corresponds to a given level of certainty.
Development On Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. A project maturity sub-class of Contingent Resources.
Development Not Viable	A discovered accumulation for which there are contingencies resulting in there being no current plans to develop or to acquire additional data at the time due to limited commercial potential. A project maturity sub-class of Contingent Resources.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. A project maturity sub-class of Contingent Resources.
Development Plan	The design specifications, timing, and cost estimates of the appraisal and development project(s) that are planned in a field or group of fields. The plan will include, but is not limited to, well locations, completion techniques, drilling methods, processing facilities, transportation, regulations, and marketing. The plan is often executed in phases when involving large, complex, sequential recovery and/or extensive areas.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information. This sub-class requires appraisal or study and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity. A project maturity sub-class of Contingent Resources.

Discovered	A petroleum accumulation where one or several exploratory wells through testing, sampling, and/or logging have demonstrated the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In this context, “significant” implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for technical recovery. (See also Known Accumulation.)
Discovered Petroleum Initially-In-Place	Quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production. Discovered PIIP may be subdivided into commercial, sub-commercial, and the portion remaining in the reservoir as Unrecoverable.
Discovered Unrecoverable	Discovered petroleum in-place resources that are evaluated, as of a given date, as not able to be recovered by the commercial and sub-commercial projects envisioned.
Dry Gas	Natural gas remaining after hydrocarbon liquids have been removed before the reference point. It should be recognized that this is a resources assessment definition and not a phase behavior definition. (Also called lean gas.)
Economic	A project is economic when it has a positive undiscounted cumulative cash flow from the effective date of the evaluation, the net revenue exceeds the net cost of operation (i.e., positive cumulative net cash flow at discount rate greater than or equal to zero percent).
Economic Interest	Interest that is possessed when an entity has acquired an interest in the minerals in-place or a license and secures, by any form of legal relationship, revenue derived from the extraction of the mineral to which he must look for a return.
Effective Date	Resource estimates of remaining quantities are “as of the given date” (effective date) of the evaluation. The evaluation must take into account all data related to the period before the "as of date.”
Entitlement	That portion of future production (and thus resources) legally accruing to an entity under the terms of the development and production contract or license.
Entity	A legal construct capable of bearing legal rights and obligations. In resources evaluations, this typically refers to the lessee or contractor, which is some form of legal corporation (or consortium of corporations). In a broader sense, an entity can be an organization of any form and may include governments or their agencies.
Established Technology	Methods of recovery or processing that have proved to be successful in commercial applications.
Estimated Ultimate Recovery (EUR)	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities that have been already produced. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.

Evaluation	The geosciences, engineering, and associated studies, including economic analyses, conducted on a petroleum exploration, development, or producing project resulting in estimates of the quantities that can be recovered and sold and the associated cash flow under defined forward conditions. (Also called assessment.)
Exploration	Prospecting for undiscovered petroleum using various techniques, such as seismic surveys, geological studies, and exploratory drilling.
Field	In conventional reservoirs, a field is typically an area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impermeable rock, laterally by local geologic barriers, or both. The term may be defined differently by individual regulatory authorities. For unconventional reservoirs without hydrodynamic influences, a field is often defined by regulatory or ownership boundaries as necessary.
Final Investment Decision (FID)	Project approval stage when the participating companies have firmly agreed to the project and the required capital funding.
Flow Test	An operation on a well designed to demonstrate the existence of recoverable petroleum in a reservoir by establishing flow to the surface and/or to provide an indication of the potential productivity of that reservoir (such as a wireline formation test). May also demonstrate the potential of certain completion techniques, particularly in unconventional reservoirs.
Fluid Contacts	The surface or interface in a reservoir separating two regions characterised by predominant differences in fluid saturations. Because of capillary and other phenomena, fluid saturation change is not necessarily abrupt or complete, nor is the surface necessarily horizontal.
Forecast Case	A descriptor applied to a scenario when production and associated cash-flow estimates are based on those conditions (including costs and product price schedules, inflation indexes, and market factors) forecast by the evaluator to reasonably exist throughout the evaluation life (i.e., defined conditions). Inflation or deflation adjustments are made to costs and revenues over the evaluation period.
Gas/Oil Ratio	Ratio that is calculated using measured natural gas and crude oil volumes at stated conditions. The gas/oil ratio may be the solution gas/oil ratio, Rs ; produced gas/oil ratio, Rp ; or another suitably defined ratio of gas production to oil production.
Geostatistical Methods	A variety of mathematical techniques and processes dealing with the collection, methods, analysis, interpretation, and presentation of large quantities of geoscience and engineering data to (mathematically) describe the variability and uncertainties within any reservoir unit or pool, specifically related here to resources estimates.
High Estimate	With respect to resources categorization, this is considered to be an optimistic estimate of the quantity that will actually be recovered from an accumulation by a project. If probabilistic methods are used, there should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

Hydrocarbons	Hydrocarbons are chemical compounds consisting wholly of hydrogen and carbon molecules.
Improved Recovery	The extraction of additional petroleum, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural forces in the reservoir. It includes waterflooding and gas injection for pressure maintenance, secondary processes, tertiary processes, and any other means of supplementing natural reservoir recovery processes. Improved recovery also includes thermal and chemical processes to improve the in-situ mobility of viscous forms of petroleum. (Also called enhanced recovery.)
Justified for Development	A development project that has reasonable forecast commercial conditions at the time of reporting and there are reasonable expectation that all necessary approvals/contracts will be obtained. A project maturity sub-class of Reserves.
Known Accumulation	An accumulation that has been discovered.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect. A project maturity sub-class of Prospective Resources.
Likelihood	Likelihood (the estimated probability or chance) is equal (1- risk). (See Probability and Risk.)
Low/Best/High Estimates	Reflects the range of uncertainty as a reasonable range of estimated potentially recoverable quantities.
Low Estimate	With respect to resources categorization, this is a conservative estimate of the quantity that will actually be recovered from the accumulation by a project. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
Lowest Known Hydrocarbons (LKH)	The deepest documented occurrence of a producible hydrocarbon accumulation as interpreted from well log, flow test, pressure measurement, core data, or other conclusive and reliable evidence.
Mean	The sum of a set of numerical values divided by the number of values in the set.
Measurement	The process of establishing quantity (volume, mass, or energy content) and quality of petroleum products delivered to a reference point under conditions defined by delivery contract or regulatory authorities.
Natural Gas	Portion of petroleum that exists either in the gaseous phase or is in solution in crude oil in a reservoir, and which is gaseous at atmospheric conditions of pressure and temperature. Natural gas may include some amount of non- hydrocarbons.

Natural Gas Liquids (NGLs)	A mixture of light hydrocarbons that exist in the gaseous phase in the reservoir and are recovered as liquids in gas processing plants. NGLs differ from condensate in two principal respects: (1) NGLs are extracted and recovered in gas plants rather than lease separators or other lease facilities, and (2) NGLs include very light hydrocarbons (ethane, propane, or butanes) as well as the pentanes-plus that are the main constituents of condensates.
Net Entitlement	That portion of future production (and thus resources) legally accruing to an entity under the terms of the development and production contract or license. Under the terms of PSCs, the producers have an entitlement to a portion of the production. This entitlement, often referred to as “net entitlement” or “net economic interest” is estimated using a formula based on the contract terms incorporating costs and profits.
Net Pay	The portion (after applying cutoffs) of the thickness of a reservoir from which petroleum can be produced or extracted. Value is referenced to a true vertical thickness measured.
Non-Hydrocarbon Gas	Associated gases such as nitrogen, carbon dioxide, hydrogen sulfide, and helium that are present in naturally occurring petroleum accumulations.
Penetration	The intersection of a wellbore with a reservoir.
Play	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation to define specific Leads or Prospects. A project maturity sub-class of Prospective Resources.
Pool	An individual and separate accumulation of petroleum in a reservoir within a field.
Primary Recovery	The extraction of petroleum from reservoirs using only the natural energy available in the reservoirs to move fluids through the reservoir rock to other points of recovery.
Probability	The extent to which an event is likely to occur, measured by the ratio of the favorable cases to the whole number of cases possible. PRMS convention is to quote cumulative probability of exceeding or equaling a quantity where P90 is the small estimate and P10 is the large estimate. (See also Uncertainty.)
Probabilistic Method	The method of estimation of resources is called probabilistic when the known geoscience, engineering, and economic data are used to generate a continuous range of estimates and their associated probabilities.
Production-Sharing Contract (PSC)	A contract between a contractor and a host government in which the contractor typically bears the risk and costs for exploration, development, and production. In return, if exploration is successful, the contractor is given the opportunity to recover the incurred investment from production, subject to specific limits and terms. Ownership of petroleum in the ground is retained by the host government; however, the contractor normally receives title to the prescribed share of the quantities as they are produced. (Also termed production-sharing agreement (PSA).

Project	A defined activity or set of activities that provides the link between the petroleum accumulation's resources sub-class and the decision-making process, including budget allocation. A project may, for example, constitute the development of a single reservoir or field, an incremental development in a larger producing field, or the integrated development of a group of several fields and associated facilities (e.g. compression) with a common ownership. In general, an individual project will represent a specific maturity level (sub-class) at which a decision is made on whether or not to proceed (i.e., spend money), suspend, or remove. There should be an associated range of estimated recoverable resources for that project. (See also Development Plan.)
Property	A defined portion of the Earth's crust wherein an entity has contractual rights to extract, process, and market specified in-place minerals (including petroleum). In general, defined as an area but may have depth and/or stratigraphic constraints. May also be termed a lease, concession, or license.
Prospect	A project associated with an undrilled potential accumulation that is sufficiently well defined to represent a viable drilling target. A project maturity sub-class of Prospective Resources.
Prospective Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.
Qualified Reserves Auditor	A reserves evaluator who (1) has a minimum of ten years of practical experience in petroleum engineering or petroleum production geology, with at least five years of such experience being in responsible charge of the estimation and evaluation of Reserves information; and (2) either (a) has obtained from a college or university of recognized stature a bachelor's or advanced degree in petroleum engineering, geology, or other discipline of engineering or physical science or (b) has received, and is maintaining in good standing, a registered or certified professional engineer's license or a registered or certified professional geologist's license, or the equivalent, from an appropriate governmental authority or professional organization. (see SPE 2007 "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information")
Qualified Reserves Evaluator	A reserves evaluator who (1) has a minimum of five years of practical experience in petroleum engineering or petroleum production geology, with at least three years of such experience being in the estimation and evaluation of Reserves information; and (2) either (a) has obtained from a college or university of recognized stature a bachelor's or advanced degree in petroleum engineering, geology, or other discipline of engineering or physical science or (b) has received, and is maintaining in good standing, a registered or certified professional engineer's license or a registered or certified professional geologist's license, or the equivalent, from an appropriate governmental authority or professional organization. (modified from SPE 2007 "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information")
Range of Uncertainty	The range of uncertainty of the in-place, recoverable, and/or potentially recoverable quantities; may be represented by either deterministic estimates or by a probability distribution. (See Resources Categories.)

Reasonable Certainty	If deterministic methods for estimating recoverable resources quantities are used, then reasonable certainty is intended to express a high degree of confidence that the estimated quantities will be recovered. Typically attributed to Proved Reserves or 1C Resources quantities.
Recoverable Resources	Those quantities of hydrocarbons that are estimated to be producible by the project from either discovered or undiscovered accumulations.
Recovery Efficiency	A numeric expression of that portion (expressed as a percentage) of in-place quantities of petroleum estimated to be recoverable by specific processes or projects, most often represented as a percentage. It is estimated using the recoverable resources divided by the hydrocarbons initially in-place. It is also referenced to timing; current and ultimate (or estimated ultimate) are descriptors applied to reference the stage of the recovery. (Also called recovery factor.)
Report	The presentation of evaluation results within the entity conducting the assessment. Should not be construed as replacing requirements for public disclosures under guidelines established by regulatory and/or other government agencies.
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. Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development project(s) applied.
Reservoir	A subsurface rock formation that contains an individual and separate natural accumulation of petroleum that is confined by impermeable barriers, pressure systems, or fluid regimes (conventional reservoirs), or is confined by hydraulic fracture barriers or fluid regimes (unconventional reservoirs).
Resources	Term used to encompass all quantities of petroleum (recoverable and unrecoverable) naturally occurring in an accumulation on or within the Earth's crust, discovered and undiscovered, plus those quantities already produced. Further, it includes all types of petroleum whether currently considered conventional or unconventional. (See Total Petroleum Initially-in-Place.)
Resources Categories	Subdivisions of estimates of resources to be recovered by a project(s) to indicate the associated degrees of uncertainty. Categories reflect uncertainties in the total petroleum remaining within the accumulation (in-place resources), that portion of the in-place petroleum that can be recovered by applying a defined development project or projects, and variations in the conditions that may impact commercial development (e.g., market availability and contractual changes). The resource quantity uncertainty range within a single resources class is reflected by either the 1P, 2P, 3P, Proved, Probable, Possible, or 1C, 2C, 3C or 1U, 2U, 3U resources categories.

Resources Classes	Subdivisions of resources that indicate the relative maturity of the development projects being applied to yield the recoverable quantity estimates. Project maturity may be indicated qualitatively by allocation to classes and sub-classes and/or quantitatively by associating a project's estimated likelihood of commerciality.
Resources Type	Describes the accumulation and is determined by the combination of the type of hydrocarbon and the rock in which it occurs.
Risk	The probability of loss or failure. Risk is not synonymous with uncertainty. Risk is generally associated with the negative outcome, the term "chance" is preferred for general usage to describe the probability of a discrete event occurring.
Royalty	A type of entitlement interest in a resource that is free and clear of the costs and expenses of development and production to the royalty interest owner. A royalty is commonly retained by a resources owner (lessor/host) when granting rights to a producer (lessee/contractor) to develop and produce that resource. Depending on the specific terms defining the royalty, the payment obligation may be expressed in monetary terms as a portion of the proceeds of production or as a right to take a portion of production in-kind. The royalty terms may also provide the option to switch between forms of payment at discretion of the royalty owner.
Stochastic	Adjective defining a process involving or containing a random variable or variables or involving likelihood or probability, such as a stochastic simulation.
Taxes	Obligatory contributions to the public funds, levied on persons, property, or income by governmental authority.
Technical Uncertainty	Indication of the varying degrees of uncertainty in estimates of recoverable quantities influenced by the range of potential in-place hydrocarbon resources within the reservoir and the range of the recovery efficiency of the recovery project being applied.
Total Petroleum Initially-in-Place	All estimated quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.
Uncertainty	The range of possible outcomes in a series of estimates. For recoverable resources assessments, the range of uncertainty reflects a reasonable range of estimated potentially recoverable quantities for an individual accumulation or a project. (See also Probability.)
Undiscovered Petroleum Initially-in-Place	That quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

Unrecoverable Resources	Those quantities of discovered or undiscovered PIIP that are assessed, 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 owing to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.
Working Interest	An entity's equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms.

Appendix 2: Nomenclature

3D	three dimensional
Bg	gas formation volume factor, in scf/rcf
Bo	oil formation volume factor, in rb/stb
Bscf	thousands of millions of standard cubic feet
CGR	condensate gas ratio
COS	geological chance of success
d	day
DST	drill stem test
ft	feet
FVF	formation volume factor
GEF	gas expansion factor
GIIP	gas initially in place
GRV	gross rock volume
HIIP	hydrocarbons initially in place
kh	permeability thickness
km	kilometres
m	metre
MD	measured depth
md or mD	millidarcy
MDT	modular dynamic tester
NTG	net to gross ratio
Phi	porosity
Phie	effective porosity
psi	pressure, measured in pounds per square inch
psia	absolute pressure, measured in pounds per square inch
PSDM	post stack depth migration
PVT	pressure volume temperature experiment
scf	standard cubic feet measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
stb	stock tank barrel (42 US gallons measured at 14.7 pounds per square inch and 60 degrees Fahrenheit)
STOIIP	stock tank oil initially in place
Sw	water saturation

TD	total depth
TVD	true vertical depth
TVDSS	true vertical depth sub-sea

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07 May 2026

TETRAGON ENERGY (PHILIPPINES) PTY LTD
100 Havelock Street, West Perth 6005
WA, Australia

SOLICITOR'S REPORT
(Re: Philippine Petroleum Interests of Tetragon Energy (Philippines) Pty Ltd)

1. Introduction

1.1. We have been engaged by Tetragon Energy (Philippines) Pty Ltd (the "**Company**") with Australian Company Number 655 451 095 to prepare this *Report* for its inclusion in a prospectus to be issued by the Company for its initial public offering and listing of its shares on the Australian Stocks Exchange.

1.2. We understand that the Company is incorporated under the laws of the Commonwealth of Australia and its ultimate beneficial shareholders are, and will be at the time of the initial public offering, predominantly Australian citizens.

1.3. The purpose of this *Report* is to outline the key rights and obligations arising from the Service Contracts for petroleum exploration and/or production in the Philippines by the Company and to summarize the legal framework governing the Company's petroleum interests under Philippine law.

1.4. This *Report* is based on information independently obtained by us from the Company and from the Department of Energy and our review of relevant Philippine laws, rules, regulations, and jurisprudence as of the date hereof. We express no opinion on matters of fact or on the accuracy of any technical, geological, or commercial data, including the specific operational details contained in the Service Contract.

2. Philippine Legal Framework Governing Petroleum Service Contracts

A. The Philippine Constitution

2.1. To begin with, the governing law for petroleum exploration and production in the Philippines is primarily the *1987 Constitution* of the Republic of the Philippines ("*1987 Constitution*").

2.2. *Section 2, Article XII* of the *1987 Constitution* pertinently provides:

> **All** lands of the public domain, waters, minerals, **coal, petroleum, and other mineral oils, all forces of potential energy**, fisheries, forests or timber, wildlife, flora and fauna, and other natural resources **are owned by the State. With the exception of agricultural lands, all other natural resources shall not be alienated. The exploration, development, and utilization of natural resources shall be under the full control and supervision of the State**. The State may directly undertake such activities, or it may enter into co-production, joint venture, or production-sharing agreements with Filipino citizens, or corporations or associations at least sixty per centum of whose capital is owned by such citizens. Such agreements may be for a period not exceeding twenty-five years, renewable for not more than twenty-five years, and under such terms and conditions as may be provided by law
>
> XXXX
>
> The President may enter into agreements with foreign-owned corporations involving either technical or financial assistance for large-scale exploration, development, and utilization of minerals, petroleum, and other mineral oils according to the general terms and conditions provided by law, based on real contributions to the economic growth and general welfare of the country.
>
> XXXX
>
> The President shall notify the Congress of every contract entered into in accordance with this provision, within thirty days from its execution.
>
> (Emphasis and underscoring supplied)

2.3. The first sentence of *Section 2* embodies the Regalian Doctrine, which means that all natural resources are owned by the State. The doctrine entails the following:

2.3.1. All natural resources shall not be alienated, except for agricultural lands. Alienation refers to the transfer of ownership, whether by sale, assignment, or other means.

2.3.2. The exploration, development, and utilization ("DEVELOPMENT") of natural resources shall be under the full control and supervision of the State, which may carry out such activities directly or through constitutionally permitted arrangements.

2.3.3. Relatedly, in the recent case of ***Ocampo vs. Macapagal-Arroyo***,[1] the Supreme Court of the Philippines[2] ("Supreme Court") declared the modes under which the State may undertake such DEVELOPMENT of its natural resources, to wit:

> (1) Directly;
>
> (2) Co-production, joint venture or production-sharing agreements with Filipino citizens or qualified corporations;
>
> (3) Congress may, by law, allow small-scale utilization of natural resources by Filipino citizens; and
>
> (4) **For the large-scale exploration, development and utilization of minerals, petroleum and other mineral oils, the President may enter into agreements with foreign-owned corporations involving technical or financial assistance**.
>
> (Emphasis supplied)

2.3.4. The fourth mode, as emphasized in the preceding paragraph, is an exception to the general norm established in the first sentence of *Section 2* of the *1987 Constitution*, which limits or reserves to Filipino citizens and corporations at least 60 percent owned by such citizens the DEVELOPMENT of natural resources.

2.3.5. As to the requirements for a *Service Contract* with a foreign-owned corporation that refers to the aforementioned fourth

[1] 943 Phil. 114 (2023).
[2] The Supreme Court of the Philippines is the final arbiter of all legal disputes in the Philippines, and its decisions form part of the law of the land.

mode, the Supreme Court provides in the case of ***Resident Marine Mammals of the Protected Seascape of Tañon Strait vs. Secretary Reyes***[3] the following:

> (1) The service contract shall be crafted in accordance with a general law that will set a standard or uniform terms, conditions and requirements xxx;
>
> (2) The President shall be the signatory for the government xxx ; and
>
> (3) Within thirty days of the executed agreement, the President shall report it to Congress.
>
> (Underscoring supplied)

As further held in the same jurisprudence, "agreements involving Technical or Financial Assistance are service contracts with safeguards," and "such service contracts may be entered into only with respect to minerals, petroleum and other mineral oils."

2.4. Accordingly, petroleum service contracts are consistent with the Regalian Doctrine because they do not transfer ownership of natural resources. In such a contract, the contractor simply provides services and technology to the Government for petroleum exploration or production. Simply stated, the State retains full control and supervision over the DEVELOPMENT of natural resources, delegating only the operational activities to a third-party contractor.[4]

2.5. In the early case of ***La Bugal-B'laan Tribal Association, Inc. vs. Ramos***,[5] the legality of service contracts in general was ultimately confirmed, to wit:

> In brief, they [the framers of the 1987 Constitution] were going to permit service contracts with foreign corporations as contractors xxx

[3] 758 Phil. 724 (2015).
[4] *See* par. 2.10 hereof.
[5] 465 Phil. 860 (2003).

2.6. Based on the foregoing, it is indubitable that petroleum service contracts with Filipino or foreign corporations are legally allowed under the 1987 Constitution.

B. Specific Laws or Statutes

2.7. The disposition, exploration, development, exploitation, and utilization of indigenous petroleum in the Philippines are governed by *Presidential Decree No. 87* ("*PD 87*"). Although enacted in 1972, prior to the adoption of the *1987 Constitution*, the Supreme Court has affirmed that *PD 87* remains valid unless expressly repealed.[6]

2.8. *PD 87* pertinently provides that the Government may undertake petroleum exploration and production indirectly through service contracts with third-party contractors, as follows:

> Section 4. *Government may undertake petroleum exploration and production.* – Subject to the existing private rights, the Government may directly explore for and produce indigenous petroleum. It may also indirectly undertake the same under service contracts as hereinafter provided. These contracts may cover free areas, national reserve areas and/or petroleum reservations, as provided for in the Petroleum Act of 1949, whether on-shore or off-shore. In every case, however, the contractor must be technically competent and financially capable as determined by the Board[7] to undertake the operations required in the contract.
>
> (Underscoring supplied)

2.9. Consequently, under *Section 5* of *PD 87*, it is required for the Petroleum Board, now the Department of Energy, to obtain the President's approval for the execution of any contract under said statute. Stated otherwise, it must be shown that the government agency or subordinate official has been authorized by the President to enter into such *Service Contract* for the government. Otherwise, it should be at least shown that the President subsequently approved of such contract explicitly.[8]

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[6] *Resident Marine Mammals of the Protected Seascape of Tañon Strait v. Secretary Reyes*, 758 Phil. 724 (2015).
[7] Formerly Petroleum Board, now the Department of Energy (DOE).
[8] 758 Phil. 724 (2015).

2.10. Relatedly, *PD 87* explains the nature of a service contract, as follows:

> Section 6. *Nature of service contract.* – In a service contract, service and technology are furnished by the service contractor for which it shall be entitled to the stipulated service fee while financing is provided by the Government to which all petroleum produced shall belong.

2.11. On the matter of the Government financing, *PD 87* provides:

> Section 7. *Special stipulation in service contract.* – Where the Government is unable to finance petroleum exploration operations or in order to induce the contractor to exert the maximum efforts to discover and produce petroleum as soon as possible, the service contract shall stipulate that if the contractor shall furnish services, technology and financing, the proceeds of the sale of the petroleum produced under the contract shall be the source of funds for payment of the service fee and the operating expenses due the contractor.

2.12. It must be noted that while *PD 87* may serve as the general law upon which a *Service Contract* for petroleum exploration and extraction may be authorized, the exploitation and utilization of this energy resource may be allowed only through a law passed by Congress[9] if the area concerned is declared to be protected or covered under the *National Integrated Protected Areas System Act of 1992*[10] ("*NIPAS Act*"). Simply put, in an instance where a protected area is involved, *PD 87*, which is a general law, is not applicable. There must be a special law passed by Congress allowing the exploitation and utilization of the said protected area.

2.13. Based on the foregoing legal bases, petroleum service contracts have clear statutory authority and are expressly permitted under the Philippine law.

3. Foreign Ownership in Petroleum Service Contractors

3.1. As discussed earlier in *Section 2.3.3.* hereof, the general rule under the *1987 Constitution* is that the DEVELOPMENT of petroleum resources may be undertaken by:

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[9] *Id.*
[10] Republic Act No. 7586.

(1) The State;

(2) The State with Filipino citizens through a co-production, joint venture, or production-sharing agreements;

(3) The State with corporations or associations at least 60% of whose capital is owned by Filipinos through a co-production, joint venture, or production sharing agreements.[11]

3.2. The exception, as discussed under *Section 2.3.4* hereof, is a *Service Contract* with a foreign-owned corporation, regardless of the percentage of foreign equity (e.g., even a 100% foreign-owned), provided, the following safeguards or requirements are met:

(1) The service contract is a Financial or Technical Assistance Agreement ("FTAA");

(2) Such service contracts may be entered into only with respect to minerals, petroleum, and other mineral oils;

(3) Such service contract shall be crafted in accordance with a general law that will set standard or uniform terms, conditions, and requirements, presumably to attain a certain uniformity in provisions and avoid the possible insertion of terms disadvantageous to the country (except for protected areas where what is required is a special law);

(4) The President shall be the signatory for the government because, supposedly before an agreement is presented to the President for signature, it will have been vetted several times over at different levels to ensure that it conforms to law and can withstand public scrutiny; and

[11] *Ocampo v. Macapagal-Arroyo*, 943 Phil. 114 (2023).

> (5) Within thirty days of the executed agreement, the President shall report it to Congress to give that branch of government an opportunity to look over the agreement and interpose timely objections, if any.[12]
>
> (Underscoring supplied)

3.3. Accordingly, the *PD 87*, which is the specific enabling law or statute regulating and governing the exploration and production of indigenous petroleum in the Philippines, contains no prohibition or limitation on foreign ownership in petroleum service contractors.

3.4. Based on the foregoing legal bases, service contractors undertaking petroleum exploration and production activities in the Philippines may be wholly foreign-owned companies.

4. Tax

4.1. The *PD 87*, specifically under *Section 12(a)*, clearly provides for the exemption of oil service contractors from all taxes except income tax, to wit:

> Section 12. *Privileges of contractor.* — The provisions of any law to the contrary notwithstanding, a contract executed under this Act may provide that the Contractor shall have the following privileges:
>
> (a) Exemption from all taxes except income tax.

4.2. Relatedly, *BIR Ruling No. 036-01* issued by the Bureau of Internal Revenue ("BIR") confirmed the exemption of service contractors from all taxes except income tax. The ruling specifically includes excise tax on the export of indigenous petroleum, thereby affirming the general tax exemption under *Section 12(a)* of *PD 87*.

4.3. As to the applicable income tax rates under the *National Internal Revenue Code* ("*Tax Code*") of the Philippines, the following rates shall apply:

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[12] *Resident Marine Mammals of the Protected Seascape of Tañon Strait v. Secretary Reyes*, 758 Phil. 724 (2015).

4.3.1. If the foreign service contractor is a corporation organized, authorized, or existing under the laws of any foreign country, engaged in trade or business within the Philippines, the contractor is deemed a resident foreign corporation, and it shall be subject to an income tax equivalent to twenty-five percent (25%) of its taxable income derived from all sources within the Philippines, unless the two percent (2%) minimum corporate income tax rate on gross income is applicable. [13]

4.3.2. If the service contractor is doing business in the Philippines through a subsidiary incorporated in the Philippines registered with the SEC, the contractor is deemed a domestic corporation, and the tax rate is twenty-five percent (25%) of its taxable income derived from all sources within the Philippines, unless the two percent (2%) minimum corporate income tax rate on gross income is applicable. Note that corporations with net taxable income not exceeding five million pesos (P5,000,000.00) and with total assets not exceeding one hundred million pesos (P100,000,000.00), excluding land on which the particular business entity's office, plant, and equipment are situated during the taxable year for which the tax is imposed, shall only be taxed at twenty percent (20%);[14]

4.3.3. Accordingly, while there is a difference in the classification of the entity, there is, however, no difference in the income tax rates applicable to either a Philippine branch or subsidiary of a foreign-owned service contractor, except in the second paragraph of *Section 4.3.2* hereof.

4.3.4. Further, the two percent (2%) minimum corporate income tax on gross income referred to above is only imposed starting on the fourth taxable year immediately following the year in which such corporation commenced its business operations in the Philippines, when said 2% minimum income tax on gross income is greater than the standard twenty-five percent (25%) tax on net income.[15]

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[13] *Section 28(A)(1)* and *(2)* of the *National Internal Revenue Code of the Philippines*.
[14] *Id.* at Section 27(A) and (E).
[15] *Id.* at Section 27(E) and 28(A).

5. Other Government Permits and Licenses

5.1. The provisions of the *Local Government Code*[16] may require the approval of pertinent local governments having jurisdiction over areas to be affected by the exploration or production activities before such activities could be undertaken.[17] These statutory provisions are broad and do not prescribe specific requirements or standardized forms for local government's consent to petroleum operations. Each Local Government Unit ("LGU"), exercising local autonomy, may set its own procedures and requirements in the absence of detailed national laws or regulations.

5.2. Relatedly, the Supreme Court in ***Republic vs. Provincial Government of Palawan***[18] held that the LGU's share in the proceeds of the development of natural resources in their areas under *Section 7*, *Article X* of the *1987 Constitution* cannot be denied on the basis of the Regalian Doctrine. While natural resources are owned by the States, the LGUs are entitled to revenue sharing in the proceeds of the utilization of the national wealth found in their respective areas. As such, petroleum service contractors and the national government must coordinate with and comply with the revenue-sharing and other regulatory requirements imposed by the LGUs to ensure lawful and smooth operations.

5.3. Furthermore, the Corporation must also secure, among others, the following standard government permits and licenses applicable to all business entities, domestic or foreign, before doing business in the Philippines:

(1) Registration of business name with the appropriate agency, such as the Securities and Exchange Commission or the Department of Trade and Industry;

(2) Tax identification number, application for withholding agent authority, and value-added tax registration and/or application for tax exemption from the Bureau of Internal Revenue;

(3) Mayor's business permit;

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[16] Republic Act No. 7160.
[17] *Id.* at Section 26.
[18] G.R. No. 170867 (2018).

(4) Municipal or city health and sanitary permits if applicable; and

(5) Fire safety inspection certificate.

6.1. Petroleum Rights in the Philippines held by the Company

6.1.1. The Company is the owner of a 37.50% participating interest and operator in *Petroleum Service Contracts 80* ("SC-80") and *Petroleum Service Contract 81* ("SC-81"). The other participants in SC-80 and SC-81 are Sunda Energy PLC (37.50%), Philodrill Limited (12.50%) and PXP Limited (12.50%). The Company is negotiating a joint operating agreement between the participants in SC-80 and SC-81 which is expected to be on commercial and customary terms. The Company is the operator of SC-80 and SC-81.

6.1.2. It is also the owner of 100% participating interest and operator of *Petroleum Service Contract 82* ("SC-82**"**).

6.1.3. SC-80 was awarded by the Philippines Department of Energy on 24 September 2025. The *Service Contract* was signed by the President Ferdinand E. Marcos Jr of the Republic of the Philippines and was presented to the Company on 08 October 2025. SC-80 is located in the Sulu Sea Basin and has an area of 780,000 hectares. Refer to Annexure "A" for a copy of the Certification issued by the Department of Energy. The initial term (Exploration Period) of SC-80 is seven (7) years, expiring on 24 September 2032. The Exploration Period may be extended for a further three (3) years provided that the Company (a) has not been in default of its exploration work and other obligations, and (b) has provided a work programme and budget for the extension period. A summary of the minimum work commitment and minimum exploration expenditures for SC-80 is set out in Annexure "D".

6.1.4. SC-81 was awarded by the Philippines Department of Energy on 24 September 2025. The service contract was signed by the President Ferdinand E. Marcos Jr of the Republic of the Philippines and was presented to the Company on 8 October 2025. SC-81 is located in the Sulu Sea Basin and has an area of 532,083 hectares. Refer to Annexure "B" for a copy of the Certification issued by the Department of Energy. The initial term (Exploration Period) of SC-81 is seven (7) years, expiring on 24 September 2032. The Exploration Period may be extended for a further three (3) years provided that the Company (a) has not been in default of its exploration work and other obligations,

and (b) has provided a work programme and budget for the extension period. A summary of the minimum work commitment and minimum exploration expenditures for SC-81 is set out in Annexure "E".

6.1.5. SC-82 was awarded by the Philippines Department of Energy on 24 September 2025. The service contract was signed by the President Ferdinand E. Marcos Jr of the Republic of the Philippines and was presented to the Company on 8 October 2025. SC-82 is located in the Cagayan Basin in Luzon and has an area of 480,000 hectares. Refer to Annexure "C" for a copy of the Certification issued by the Department of Energy. The initial term (Exploration Period) of SC-82 is seven (7) years, expiring on 24 September 2032. The Exploration Period may be extended for a further three (3) years provided that the Company (a) has not been in default of its exploration work and other obligations, and (b) has provided a work programme and budget for the extension period. A summary of the minimum work commitment and minimum exploration expenditures for SC-82 is set out in Annexure "F".

6.2. Rights of the Company in the Petroleum Service Contracts

6.2.1. The contractor shall have the following rights:

(a) Exemption from all taxes, except Philippine Income Tax, pursuant to *Section 12.04* hereof, under the provisions of the National Internal Revenue Code and the Act, as amended;

(b) Exemption from all levies, tariffs, duties, compensating tax and value added tax pursuant to *Section 12.04* hereof, on the importation into the Philippines of all machinery, equipment, spare parts, and all materials required for, and to be used exclusively by the CONTRACTOR or its Subcontractor(s) in the Petroleum Operations, on the following conditions:

(1) said machinery, equipment, spare parts, and materials of comparable price, quality and quantity are not manufactured domestically nor readily available to the CONTRACTOR or its Subcontractor(s) within the same or better time frame;

said machinery, equipment and spare parts are directly and actually needed, and will be used exclusively by the CONTRACTOR in its Petroleum Operations or in the

operations for it by a Subcontractor(s) and are covered by shipping documents in the name of the CONTRACTOR to whom the shipment will be delivered directly by the customs authorities; and

(2) the prior approval of the DEPARTMENT was obtained by the CONTRACTOR prior to the importation of such machinery, equipment, spare parts, and materials, which approval shall not be unreasonably withheld;

Provided, however, that if the CONTRACTOR or its Subcontractor(s) sell, transfer, or dispose of such machinery, equipment, spare parts, and materials without the prior approval of the DEPARTMENT, the CONTRACTOR shall pay twice the amount of the tax exemption granted on the equipment sold, transferred or disposed;

Provided further, that the DEPARTMENT shall allow, and approve the sale, transfer, or disposition of the said items within the Philippines, without tax, if made:

(1) to another contractor who is granted similar Philippine duty-exempt status;

(2) for reasons of technical obsolescence; or,

(3) for purposes of replacement to improve and/or expand the Petroleum Operations of the CONTRACTOR;

(c) Exemption from posting of performance/surety bond during the Production Period of the Contract;

(d) Exemption, upon approval by the DEPARTMENT, which approval shall not be unreasonably withheld, from laws, regulations and/or ordinances restricting the exportation of machinery, equipment, spare parts and materials which were imported solely for the CONTRACTOR's Petroleum Operations when no longer needed;

(e) Exportation of Petroleum subject to the obligation to supply a portion of domestic requirements as provided in Section 6.01(x) above;

(f) Entry, upon endorsement of the DEPARTMENT to the appropriate governmental agency for the issuance of necessary visa, which endorsement shall not be unreasonably withheld, of alien technical and specialized personnel (including the immediate members of their families), who may exercise their professions solely for the Petroleum Operations of the CONTRACTOR; *Provided,* that if the employment or connection of such alien with the CONTRACTOR ceases, the applicable laws and regulations on immigration shall apply to him and his immediate family; *Provided further,* that Filipinos shall be given preference to positions for which they have adequate training and experience (as determined by the CONTRACTOR); *Provided finally,* that the CONTRACTOR shall adopt and implement a training program for Filipinos along technical or specialized lines which will be part of the approved Work Program and Budget;

(g) Have at all times the right of ingress and egress to the Contract Area and related facilities wherever located;

(h) Subject to the regulations of the *Bangko Sentral ng Pilipinas*, be entitled to:

(1) repatriate the capital investment and all costs and expenses actually spent on or brought into the country in Foreign Currency or other assets and registered with the *Bangko Sentral ng Pilipinas*;

(2) retain abroad all Foreign Currency representing proceeds arising from exports accruing to the CONTRACTOR and/or its designated Operator over and above:

(a) the Foreign Currency to be converted into pesos in an amount sufficient to cover, or equivalent to, the local costs for administration and operations of the exported Petroleum; and,

(b) revenues payable to the DEPARTMENT on such Petroleum exported;

(3) convert into Foreign Currency and remit abroad at prevailing rates no less favorable to the CONTRACTOR than those available to any other purchaser of foreign currencies, any excess balances of the CONTRACTOR's peso earnings

from Petroleum production and sale over and above the current working capital they require; and,

(4) convert Foreign Currency into Philippine currency for all purposes in connection with its Petroleum Operations at prevailing rates no less favorable to the CONTRACTOR than those available to any other purchaser of such currency;

(i) Be entitled to the Filipino Participation Incentive Allowance (FPIA) and any special allowances that may be granted by law or relevant issuances of the DEPARTMENT;

(j) Exemption from the investment requirements of foreign corporations under Section 143 of Republic Act No. 11232, otherwise known as the "Revised Corporation Code of the Philippines";

(k) May block off, upon notice to and approval by the DEPARTMENT, which approval shall not be unreasonably withheld, any delineated structure that straddles or adjoins a portion of the Contract Area and a free area. Such blocked-off area(s) shall thereupon be deemed a part of the Contract Area subject to the terms and conditions of this Contract and, subject further to Section IV hereof; and

(l) Relinquish this Contract upon settlement of all other obligations under this Contract. Any unfulfilled financial obligations shall survive the relinquishment of this Contract.

6.3. Good Standing and Compliance

Based on the Certifications issued by the Department of Energy dated March 2026, annexed as Annexures "A", "B" and "C", together with the documents reviewed and information obtained from the Department of Energy and the Company, we confirm the following in respect of each of SC-80, SC-81 and SC-82:

(a) each Service Contract is currently in full force and effect and has not been surrendered, revoked, suspended or cancelled in whole or in part;

(b) no application has been made, or threatened, for the forfeiture, revocation or cancellation of any Service Contract;

(c) there are no proceedings, disputes or investigations (current, pending or threatened) in relation to any Service Contract;

(d) the Company is not in breach or default of any of its obligations under the Service Contracts and no notices of default, breach or non-compliance have been issued or received by the Company;

(e) all rents, fees, levies, bonds and other payments due under or in connection with the Service Contracts have been paid when due;

(f) the Company has complied with its minimum work commitment and minimum exploration expenditure obligations under each Service Contract to date; and

(g) there are no royalty agreements, overriding royalty interests, farm-in or farm-out agreements, encumbrances, caveats or other third-party interests affecting any of the Service Contracts.

6.4. Access and ability to conduct activities

Based on the Certificates of Non-Overlap issued by the National Commission on Indigenous Peoples, together with related certifications and documents reviewed and information obtained from the Department of Energy and the Company, the contract areas for SC-80, SC-81 and SC-82 have not been identified in the materials reviewed as overlapping with ancestral domains or protected areas under the National Integrated Protected Areas System (NIPAS).

The materials reviewed further indicate that no Free, Prior and Informed Consent (FPIC) requirements are presently applicable in respect of the contract areas. Copies of the relevant Certificates of Non-Overlap issued by the National Commission on Indigenous Peoples are annexed as Annexures “G”, “H” and “I”.

We note that there may be overlapping solar development areas within the areas covered by the Service Contracts. Such overlapping development areas are permitted under applicable Philippine energy law and do not restrict or prohibit the Company’s petroleum exploration activities under the Service Contracts.

7. In conclusion, we confirm that the Company, as a foreign company, is legally allowed to hold petroleum service contracts in the Philippines and is the owner of participating interests in, and operator of, Petroleum

Service Contracts Nos. 80, 81, and 82. Based on the Certifications issued by the Department of Energy dated March 2026 and our enquiries, each of SC-80, SC-81 and SC-82 is in full force and effect, the Company is the registered holder of the participating interests stated in this Report, and the Company has no pending violation with the Department of Energy in respect of any Service Contract.

Disclaimer. This Report is issued solely for the purpose stated in *Section 1* hereof, based on the documents and information made available to us and our review of relevant Philippine laws, rules, regulations, and jurisprudence as of the date hereof, which may be modified, amended, or reinterpreted subsequently. This *Report* is provided solely for the Company's benefit and may not be relied upon, in whole or in part, by any other person for any purpose.

Very truly yours,

PARADA RIVERA EVARDONE AND SALALIMA
ATTORNEYS- AT- LAW
Unit 1802, 18th Floor, West Tower
Tektite Towers (formerly Philippine Stock Exchange Centre)
Exchange Road, Ortigas Center, Pasig City, Philippines
Email address: docket@preslaw.com
Contact No.: (02) 7219 0016

By:

ATTY. NEIL ALLAN D. RIVERA
PTR. No. 3985789; 01/06/2026; Pasig City
IBP Membership Receipt No.: 594593; 01/14/2026
Roll of Attorneys No. 63105
MCLE Compliance No. VIII-0035054
Issued on 20 May 2025

HECTOR DOMINIC D. ALEMAN
PTR. No. 3985784; 01/06/2026; Pasig City
IBP Membership Receipt No.: 588734; 01/05/2026
Roll of Attorneys No. 93871
MCLE Compliance No. N/A
Admitted to the Bar 2025

ANNEXURE A

BAGONG PILIPINAS

CERTIFICATION

This is to certify that **Tetragon Energy (Philippines) Pty. Ltd.** (the "Company") is a member of two (2) Petroleum Service Contracts (SC) as listed below:

Service Contract	Participating Interest
SC No. 80 (Sulu Sea)	37.50%
SC No. 81 (Sulu Sea)	37.50%

This is to further certify that the abovementioned SCs are still valid and subsisting and that the company has no pending violation with the Department of Energy and the Ministry of Environment, Natural Resources, and Energy.

The certification is issued upon request of the Company for any transaction in relation to its Service Contracts and for other legal purposes it may serve.

Given this 18th day of March 2026, Bonifacio Global City, Taguig City, Metro Manila

DEMUJIN F. ANTIPORDA
OIC – Director
Energy Resource Development Bureau

NASIRI B. ABAS
Director General for Energy
MENRE

ANNEXURE B

CERTIFICATION

This is to certify that **Tetragon Energy (Philippines) Pty. Ltd.** (the "Company") is a member of two (2) Petroleum Service Contracts (SC) as listed below:

Service Contract	Participating Interest
SC No. 80 (Sulu Sea)	37.50%
SC No. 81 (Sulu Sea)	37.50%

This is to further certify that the abovementioned SCs are still valid and subsisting and that the company has no pending violation with the Department of Energy and the Ministry of Environment, Natural Resources, and Energy.

The certification is issued upon request of the Company for any transaction in relation to its Service Contracts and for other legal purposes it may serve.

Given this 18th day of March 2026, Bonifacio Global City, Taguig City, Metro Manila

DEMUJIN F. ANTIPORDA
OIC – Director
Energy Resource Development Bureau

NASIRI B. ABAS
Director General for Energy
MENRE

ANNEXURE C

Republic of the Philippines
Department of Energy
(Kagawaran ng Enerhiya)

BAGONG PILIPINAS

CERTIFICATION

This is to certify that **Tetragon Energy (Philippines) Pty. Ltd.** (the "Company") is the operator of Petroleum Service Contract (SC) No. 82 and holds 100% participating interest in the Contract.

SC 82, located in the Cagayan Basin in Luzon covering an area of Four hundred and eighty thousand (480,000.00) hectares, was awarded by the Department of Energy on 24 September 2025 pursuant to Presidential Decree No. 87. SC 82 was signed by the President of the Republic of the Philippines, Ferdinand R. Marcos Jr., and was presented to the Company on 08 October 2025.

This is to further certify that SC 82 is still valid and subsisting and that the company has no pending violation with the Department of Energy.

The certification is issued upon request of the Company for any transaction in relation to its SC 82 and for other legal purposes it may serve.

Given this 12th day of March 2026, Bonifacio Global City, Taguig City, Metro Manila

DEMUJIN F. ANTIPORDA
OIC - Director
Energy Resource Development Bureau

Energy Center, Rizal Drive cor. 34th Street, Bonifacio Global City, Taguig City
Philippines 1632 Tel. No. (Trunkline) (632) 8479-2900
Website: www.doe.gov.ph; E-mail: infocenter@doe.gov.ph

ANNEXURE D

SECTION V
MINIMUM WORK COMMITMENT AND MINIMUM EXPLORATION EXPENDITURES

5.01 The CONTRACTOR shall begin to perform the Exploration Operations from the Effectivity of the Contract.

5.02 The CONTRACTOR shall fulfill the minimum exploration work commitment for each Sub-Phase of the Exploration Period in accordance with the following provisions:

(a) During the 1st Sub-Phase of the Exploration Period covering Contract Years One (1) and Two (2) (being 24 months) the CONTRACTOR shall conduct data gathering and G&G studies, 3D Pre-Stack Depth Migrated Data reprocessing, and seismic interpretation and geological studies. The expected equivalent total minimum expenditure for Sub-Phase 1 is One Million US Dollars (US$ 1,000,000.00).

(b) During the 2nd Sub-Phase of the Exploration Period covering Contract Years Three (3) and Four (4) (being 24 months), the CONTRACTOR shall conduct advanced geophysical studies including inversion, acoustic impedance studies or Artificial Intelligence Interpretations (AI). The CONTRACTOR shall also conduct seismic interpretation and geological studies, resource and risk analysis, preliminary well planning, and scoping development & economics studies. The expected equivalent total minimum expenditure for Sub-Phase 2 is One Million US Dollars (US$ 1,000,000.00).

(c) During the 3rd Sub-Phase of the Exploration Period covering Contract Year Five (5) until the First Half of Contract Year Six (6) (being 18 months), the CONTRACTOR shall conduct well planning and drilling studies, drill one (1) exploration well with minimum depth of 3000m TVDSS, and conduct post-well G&G studies in addition to development and commercial studies. The expected equivalent total minimum expenditure for Sub-Phase 3 is Fifteen Million Five Hundred Thousand US Dollars (US $15,500,000.00).

(d) During the 4th Sub-Phase of the Exploration Period covering the Second Half of Contract Year Six (6), until the End of Contract Year Seven (7) (being 18 months), the CONTRACTOR shall drill one (1) exploration well or appraisal well. The expected equivalent total minimum expenditure for Sub-Phase 4 is Fifteen Million US Dollars (US$ 15,500,000.00).

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(02) 7219 0016 | 09171281157
www.preslawfirm.com

(e) If the CONTRACTOR is able to drill one (1) Deep Well, then such Deep Well drilling shall be considered as equivalent to drilling two (2) Exploration Wells committed under this Contract.

5.03 At least thirty (30) calendar days before the end of each Sub-Phase of the Exploration Period, the CONTRACTOR, based on the following options in accordance with the provisions of this Contract shall notify in writing the GOVERNMENT either to:

(a) enter the next Sub-Phase and continue exploration upon prior approval by the GOVERNMENT; or

(b) conduct only an Appraisal Work Program in the Petroleum discoveries awaiting appraisal based on procedures under Section VIII of the Contract, and/or Development and Marketing Operations as approved by the GOVERNMENT, provided that the minimum obligations during the current exploration Sub-Phase have been fulfilled; and the areas under Section IV hereof have been relinquished; or

(c) terminate the Contract.

5.04 If the CONTRACTOR fails to comply with the work obligations during any Sub-Phase provided for in this Contract, it shall pay to the GOVERNMENT the amount it should have spent but did not in direct execution of its work obligations. If the CONTRACTOR elects to terminate the Contract before the end of any Sub-Phase during the Exploration Period and there are unfulfilled work obligations in the Sub-Phase in question, the CONTRACTOR shall pay the value of the unfulfilled balance of the minimum exploration work commitment for such Sub-Phase in US Dollars. However, if the minimum exploration work commitment for any Sub-Phase during the Exploration Period is fulfilled while its expected corresponding minimum exploration expenditures are not fulfilled, the unspent part shall be deemed as a saving and shall not be paid to the GOVERNMENT.

5.05 Subject to the approval of the GOVERNMENT and provided that the work commitments in the Work Program and Budget for the preceding Sub-Phase have been fulfilled, the CONTRACTOR may commence to the next Sub-Phase during the Exploration Period earlier than the scheduled date.

ANNEXURE E

SECTION V

MINIMUM WORK COMMITMENT AND MINIMUM EXPLORATION EXPENDITURES

5.01 The CONTRACTOR shall begin to perform the Exploration Operations from the Effectivity of the Contract.

5.02 The CONTRACTOR shall fulfill the minimum exploration work commitment for each Sub-Phase of the Exploration Period in accordance with the following provisions:

(a) During the 1st Sub-Phase of the Exploration Period covering Contract Years One (1) and Two (2) (being 24 months) the CONTRACTOR shall conduct initial data gathering and G&G studies, reprocess at least 1,600 square kilometers of vintage 3D seismic data, reprocess at least 1,000 line-kilometers of 2003 2D vintage seismic data, and conduct seismic interpretation and geological studies. The expected equivalent roral minimum expenditure for Sub-Phase 1 is One Million US Dollars (US$ 1,000,000.00).

(b) During the 2nd Sub-Phase of the Exploration Period covering Contract Years Three (3) and Four (4) (being 24 months), the CONTRACTOR shall conduct geophysical studies, seismic interpretation and geological studies, resource and risk analysis, preliminary well planning, and scoping development and economics studies. The expected equivalent total minimum expenditure for Sub-Phase 2 is One Million US Dollars (US$ 1,000,000.00).

(c) During the 3rd Sub-Phase of the Exploration Period covering Contract Year Five (5) until the First Half of Contract Year Six (6) (being 18 months), the CONTRACTOR shall conduct well planning and drilling studies, drill one (1) exploration well with minimum 2000m TVDSS, and conduct post-well G&G studies, and development and commercial studies. The expected equivalent total minimum expenditure for Sub-Phase 3 is Fifteen Million Five Hundred Thousand US Dollars (US $15,500,000.00).

(d) During the 4th Sub-Phase of the Exploration Period covering the Second Half of Contract Year Six (6) until the end of Contract Year Seven (7) (being 18 months), the CONTRACTOR shall conduct well planning and drilling a further new exploration or appraisal well. The expected equivalent total minimum expenditure for Sub-Phase 4 is Fifteen Million Five Hundred Thousand US Dollars (US$ 15,500,000.00).

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www.preslawfirm.com

(e) If the CONTRACTOR is able to drill one (1) Deep Well, then such Deep Well drilling shall be considered as equivalent to drilling two (2) Exploration Wells committed under this Contract.

5.03 At least thirty (30) calendar days before the end of each Sub-Phase of the Exploration Period, the CONTRACTOR, based on the following options in accordance with the provisions of this Contract shall notify in writing the GOVERNMENT either to:

(a) enter the next Sub-Phase and continue exploration upon prior approval by the GOVERNMENT; or

(b) conduct only an Appraisal Work Program in the Petroleum discoveries awaiting appraisal based on procedures under Section VIII of the Contract, and/or Development and Marketing Operations as approved by the GOVERNMENT, provided that the minimum obligations during the current exploration Sub-Phase have been fulfilled; and the areas under Section IV hereof have been relinquished; or

(c) terminate the Contract.

5.04 If the CONTRACTOR fails to comply with the work obligations during any Sub-Phase provided for in this Contract, it shall pay to the GOVERNMENT the amount it should have spent but did not in direct execution of its work obligations. If the CONTRACTOR elects to terminate the Contract before the end of any Sub-Phase during the Exploration Period and there are unfulfilled work obligations in the Sub-Phase in question, the CONTRACTOR shall pay the value of the unfulfilled balance of the minimum exploration work commitment for such Sub-Phase in US Dollars. However, if the minimum exploration work commitment for any Sub-Phase during the Exploration Period is fulfilled while its expected corresponding minimum exploration expenditures are not fulfilled, the unspent part shall be deemed as a saving and shall not be paid to the GOVERNMENT.

5.05 Subject to the approval of the GOVERNMENT and provided that the work commitments in the Work Program and Budget for the preceding Sub-Phase have been fulfilled, the CONTRACTOR may commence to the next Sub-Phase during the Exploration Period earlier than the scheduled date.

ANNEXURE F

SECTION V

MINIMUM WORK COMMITMENT AND MINIMUM EXPLORATION EXPENDITURES

5.01 The CONTRACTOR shall begin to perform the Exploration Operations from the Effectivity of the Contract.

5.02 The CONTRACTOR shall fulfill the minimum exploration work commitment for each Sub-Phase of the Exploration Period in accordance with the following provisions:

(a) During the 1st Sub-Phase of the Exploration Period covering Contract Years One (1) and Two (2) (being 24 months), the CONTRACTOR shall source, secure, and reprocess a total of 3,600 line-km. of 2D seismic data; source and digitize a total of

25 well data; and, conduct G&G and geochemical studies (with corresponding G&A cost) amounting to an expected equivalent total minimum expenditure of Four Hundred and Twenty Five Thousand United States Dollars (US$ 425,000.00).

(b) During the 2nd Sub-Phase of the Exploration Period covering Contract Years Three (3) and Four (4) (being 24 months), the CONTRACTOR shall conduct seismic interpretation; stratigraphic and structural studies; prospect screening for seismic acquisition; and, G&G studies (with corresponding G&A cost) amounting to an expected equivalent total minimum expenditure of Four Hundred and Fifty Thousand United States Dollars (US$ 450,000.00).

(c) During the 3rd Sub-Phase of the Exploration Period covering the Contract Year Five (5) (being 12 months), the CONTRACTOR shall conduct acquisition of 200 line-km of geophysical data (Aero Gravity and Magnetic); and, G&G studies (with corresponding G&A cost) amounting to an expected equivalent total minimum expenditure of Five Hundred Thousand United States Dollars (US$ 500,000.00).

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(d) During the 4th Sub-Phase of the Exploration Period covering Contract Year Six (6) (being 12 months), the CONTRACTOR shall conduct well planning; and, G&G studies (with corresponding G&A cost) amounting to an expected equivalent total minimum expenditure of Seven Hundred Thousand United States Dollars (US$ 700,000.00).

(e) During the 5th Sub-Phase of the Exploration Period covering Contract Year Seven (7) (being 12 months), the CONTRACTOR shall drill one (1) Exploration Well; and, conduct G&G studies (with corresponding G&A cost) amounting to an expected equivalent total minimum expenditure of Five Million and Two Hundred Thousand United States Dollars (US$ 5,200,000.00).

(f) If the CONTRACTOR is able to drill one (1) Deep Well, then such Deep Well drilling shall be considered as equivalent to drilling two (2) Exploration Wells committed under this Contract.

5.03 At least thirty (30) calendar days before the end of each Sub-Phase of the Exploration Period, the CONTRACTOR, based on the following options in accordance with the provisions of this Contract shall notify in writing the DEPARTMENT either to:

(a) enter the next Sub-Phase and continue exploration upon prior approval by the DEPARTMENT; or

(b) conduct only an Appraisal Work Program in the Petroleum discoveries awaiting appraisal based on procedures under Section VIII of the Contract, and/or Development and Marketing Operations as approved by the DEPARTMENT, provided that the minimum obligations during the current exploration Sub-Phase have been fulfilled; and the areas under Section IV hereof have been relinquished; or

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(c) terminate the Contract.

5.04 If the CONTRACTOR fails to comply with the work obligations during any Sub-Phase provided for in this Contract, it shall pay to the DEPARTMENT the amount it should have spent but did not in direct execution of its work obligations. If the CONTRACTOR elects to terminate the Contract before the end of any Sub-Phase during the Exploration Period and there are unfulfilled work obligations in the Sub-Phase in question, the CONTRACTOR shall pay the value of the unfulfilled balance of the minimum exploration work commitment for such Sub-Phase in United States Dollars. However, if the minimum exploration work commitment for any Sub-Phase during the Exploration Period is fulfilled while its expected corresponding minimum exploration expenditures are not fulfilled, the unspent part shall be deemed as a saving and shall not be paid to the DEPARTMENT.

5.05 Subject to the approval of the DEPARTMENT and provided that the work commitments in the Work Program and Budget for the preceding Sub-Phase have been fulfilled, the CONTRACTOR may commence to the next Sub-Phase during the Exploration Period earlier than the scheduled date.

ANNEXURE G

Republic of the Philippines
Bangsamoro Autonomous Region in Muslim Mindanao
MINISTRY OF INDIGENOUS PEOPLES' AFFAIRS
San Isidro Street, Rosary Heights 10
Cotabato City 9600
mipa@bangsamoro.gov.ph

CERTIFICATE OF NON-OVERLAP

TO WHOM IT MAY CONCERN:

THIS IS TO CERTIFY that the site/area applied for the issuance of a Certificate of Non-Overlap (CNO) of the **TRIANGLE ENERGY (Global) LIMITED, SUNDA ENERGY PLC, PXP ENERGY CORPORATION and PHILODRILL CORPORATION (CONSORTIUM)** with office address on ***Suite 2, Ground Floor, 100 Havelock St., West Perth WA 6005, Australia*** for their ***"PDA-BP No. 2 under the 1st BARMM Conventional Energy Bid Round for Petroleum Exploration covering 780, 000 hectares"*, DOES NOT AFFECT NOR OVERLAP ANY ANCESTRAL DOMAIN/LAND/WATER OF THE INDIGENOUS CULTURAL COMMUNITIES/INDIGENOUS PEOPLES**. The said applied area is situated in the Sulu Sea Basin.

THIS CERTIFICATION is issued based on the Field-Based Investigation Report conducted by this Ministry as prescribed by MIPA Guidelines on FPIC Process and in accordance with Article IX, Section 3, letter (e) Free, Prior, and Informed Consent of the Republic Act No. 11054 of 2018.

CERTIFIES FINALLY, that this Certificate of Non-Overlap (CNO) is relevant only to the above-mentioned proposed projects/activities and may be cancelled/revoked upon the receipt of any order contrary to this Certification as the case may be.

Issued this **25th day of November 2024 at MIPA-BARMM Regional Office**, Cotabato City.

MELANIO U. ULAMA
Minister

Bangsamoro Autonomous Region in Muslim Mindanao
Ministry of Indigenous Peoples' Affairs
Record Section
RELEASED
Name:
Date: 11-25-24 Time: 11:21

Control No. 044
Series of 2024

ANNEXURE H

Republic of the Philippines
Bangsamoro Autonomous Region in Muslim Mindanao
MINISTRY OF INDIGENOUS PEOPLES' AFFAIRS
San Isidro Street, Rosary Heights 10
Cotabato City 9600
mipa@bangsamoro.gov.ph

CERTIFICATE OF NON-OVERLAP

TO WHOM IT MAY CONCERN:

THIS IS TO CERTIFY that the site/area applied for the issuance of a Certificate of Non-Overlap (CNO) of the **TRIANGLE ENERGY (Global) LIMITED, SUNDA ENERGY PLC, PXP ENERGY CORPORATION and PHILODRILL CORPORATION (CONSORTIUM)** with office address on ***Suite 2, Ground Floor, 100 Havelock St., West Perth WA 6005, Australia*** for their ***"PDA-BP No. 3 under the 1st BARMM Conventional Energy Bid Round for Petroleum Exploration covering 532, 083 hectares"***, **DOES NOT AFFECT NOR OVERLAP ANY ANCESTRAL DOMAIN/LAND/WATER OF THE INDIGENOUS CULTURAL COMMUNITIES/INDIGENOUS PEOPLES**. The said applied area is situated in the Sulu Sea Basin.

THIS CERTIFICATION is issued based on the Field-Based Investigation Report conducted by this Ministry as prescribed by MIPA Guidelines on FPIC Process and in accordance with Article IX, Section 3, letter (e) Free, Prior, and Informed Consent of the Republic Act No. 11054 of 2018.

CERTIFIES FINALLY, that this Certificate of Non-Overlap (CNO) is relevant only to the above-mentioned proposed projects/activities and may be cancelled/revoked upon the receipt of any order contrary to this Certification as the case may be.

Issued this **25th day of November 2024 at MIPA-BARMM Regional Office**, Cotabato City.

MELANIO U. ULAMA
Minister

Bangsamoro Autonomous Region in Muslim Mindanao
Ministry of Indigenous Peoples' Affairs
Record Section
RELEASED
Name:
Date: 11-25-24 Time: 11:51

Control No. 047
Series of 2024

ANNEXURE I

REPUBLIC OF THE PHILIPPINES
OFFICE OF THE PRESIDENT
NATIONAL COMMISSION ON INDIGENOUS PEOPLES
REGIONAL OFFICE NO. 02

Control No. CNO-Region II-EVOSS-2025-006-I-004

CERTIFICATE OF NON-OVERLAP

TO WHOM IT MAY CONCERN:

THIS IS TO CERTIFY that the applied area for the **Oil and Gas Exploration and Production** of the **Triangle Energy (Global) Limited** with office address at Suite 2, Ground Floor 100 Havelock St., West Perth, WA 6005 Australia located at the Provinces of Cagayan, Isabela and Quirino covering a total area of 480,000 hectares **DOES NOT OVERLAP** any Ancestral Domain/Land of Indigenous Cultural Communities/ Indigenous Peoples based on the assessment of secondary data and field-based investigation conducted in accordance with National Commission on Indigenous Peoples Administrative Order No. 3, Series of 2012.

THIS IS TO CERTIFY FURTHER that the proponent is required to undergo Free and Prior Informed Consent (FPIC) process in accordance with the Affidavit of Undertaking, in the event it is determined that there is, in fact, an overlap, in whole or in part, with any ancestral domain/land.

This Office, however, reserves whatever action needed to be undertaken to protect the rights and interest of the Indigenous Cultural Communities/Indigenous Peoples concerned, including the cancellation/revocation of this certification, as the case maybe.

Issued in compliance with Section 59 of Republic Act No. 8371, otherwise known as the Indigenous Peoples Rights Act (IPRA) of 1997.

Issued on April 15, 2025 at Tuguegarao City, Cagayan.

Certified:

RONALDO M. DAQUIOAG, CESO III
Regional Director

Concurred:

SIMPLICIA P. HAGADA
Commissioner

Copy Furnished:
1. **ADO**
2. **Office of the Ethnographic Commissioner**
3. **ATTY. MARVIN CHAN**
   Triangle Energy Global Limited
   Suite 2, Ground Floor 100 Havelock St.,
   West Perth, WA 6005 Australia
4. **Isabela PO**
5. **Quirino PO**
6. **Cagayan CSC**
7. **File**

Republic of the Philippines
Department of Energy
(Kagawaran ng Enerhiya)

BAGONG PILIPINAS

07 April 2025

ATTY. RONALDO M. DAQUIOAG
Regional Director
National Commission on Indigenous Peoples (NCIP) Region II
Dalan na Paccorofun, Carig Sur, Tuguegarao City
(02) 875 1200 Local 0200
Email: region2@ncip.gov.ph

Subject: **Endorsement for Triangle Energy (Global) Limited (Triangle) for the Issuance of Certificate of Non-Overlap or Certification Precondition**

Dear **Dir. Daquioag**:

The Department of Energy (DOE) would like to endorse Triangle to the NCIP for the issuance of Certificate of Non-Overlap or Certification Precondition, whichever is applicable.

Triangle is a Petroleum Service Contract (PSC) applicant of the DOE for Nominated Area No. 11 (NA-11) (located in the Cagayan Basin) under the Philippine Conventional Energy Contracting Program (PCECP). In line with this request, attached is the map of NA-11 for NCIP's reference.

NCIP's favorable and prompt action on the matter is highly appreciated. Thank you very much.

Very truly yours,

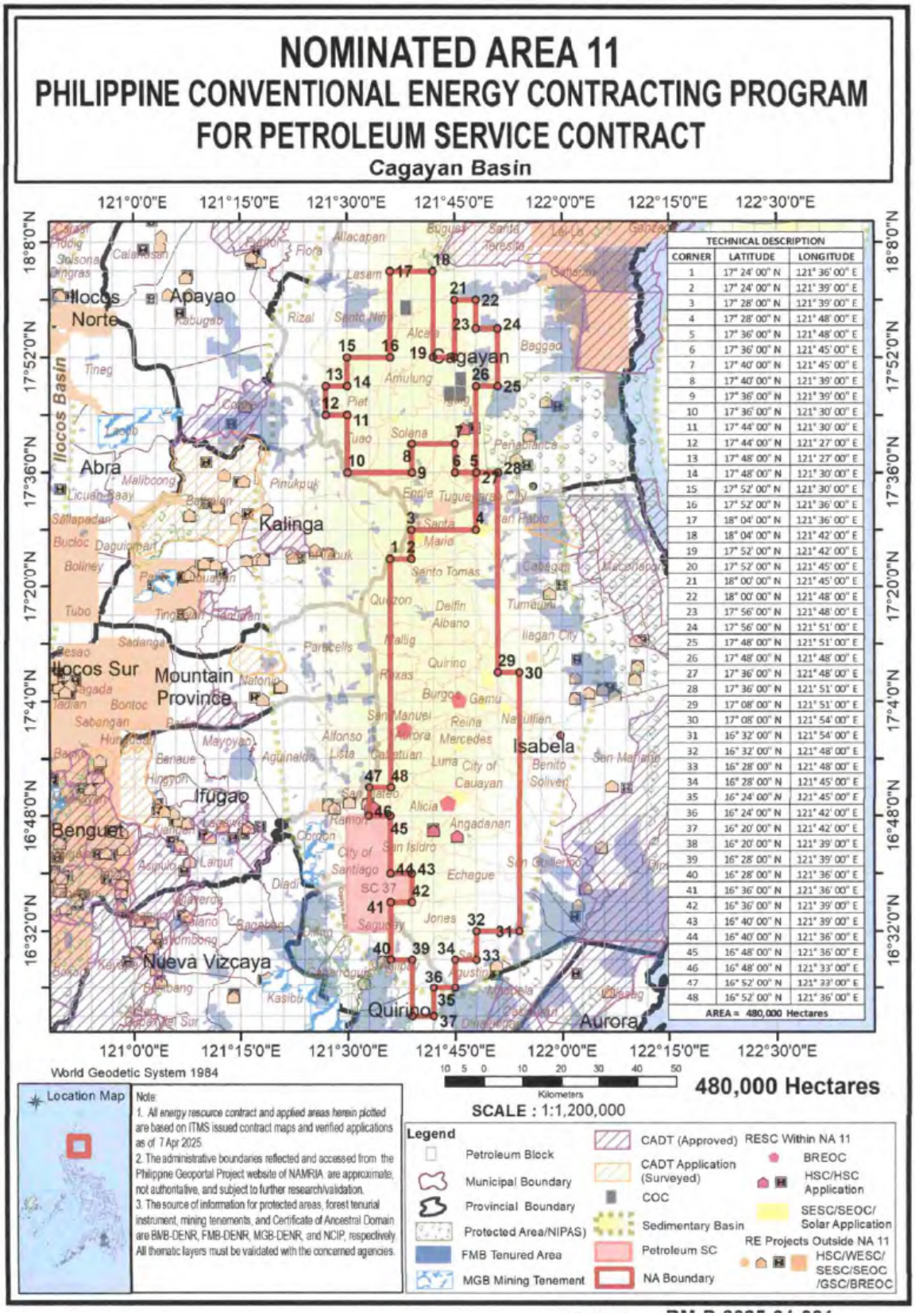
NENITO C. JARIEL, JR.
Director IV
Energy Resource Development Bureau

Cc:
Atty. Arthur K. Herman
Director IV, Ancestral Domains Office (ADO)
NCIP

Mr. Marvin A. Chan
Chief Financial Officer
Triangle Energy (Global) Limited

Ms. Simplicia P. Hagada
Ethnographic Commissioner, Region II
NCIP

NOMINATED AREA 11
PHILIPPINE CONVENTIONAL ENERGY CONTRACTING PROGRAM
FOR PETROLEUM SERVICE CONTRACT
Cagayan Basin



TECHNICAL DESCRIPTION		
CORNER	LATITUDE	LONGITUDE
1	17° 24' 00" N	121° 36' 00" E
2	17° 24' 00" N	121° 39' 00" E
3	17° 28' 00" N	121° 39' 00" E
4	17° 28' 00" N	121° 48' 00" E
5	17° 36' 00" N	121° 48' 00" E
6	17° 36' 00" N	121° 45' 00" E
7	17° 40' 00" N	121° 45' 00" E
8	17° 40' 00" N	121° 39' 00" E
9	17° 36' 00" N	121° 39' 00" E
10	17° 36' 00" N	121° 30' 00" E
11	17° 44' 00" N	121° 30' 00" E
12	17° 44' 00" N	121° 27' 00" E
13	17° 48' 00" N	121° 27' 00" E
14	17° 48' 00" N	121° 30' 00" E
15	17° 52' 00" N	121° 30' 00" E
16	17° 52' 00" N	121° 36' 00" E
17	18° 04' 00" N	121° 36' 00" E
18	18° 04' 00" N	121° 42' 00" E
19	17° 52' 00" N	121° 42' 00" E
20	17° 52' 00" N	121° 45' 00" E
21	18° 00' 00" N	121° 45' 00" E
22	18° 00' 00" N	121° 48' 00" E
23	17° 56' 00" N	121° 48' 00" E
24	17° 56' 00" N	121° 51' 00" E
25	17° 48' 00" N	121° 51' 00" E
26	17° 48' 00" N	121° 48' 00" E
27	17° 36' 00" N	121° 48' 00" E
28	17° 36' 00" N	121° 51' 00" E
29	17° 08' 00" N	121° 51' 00" E
30	17° 08' 00" N	121° 54' 00" E
31	16° 32' 00" N	121° 54' 00" E
32	16° 32' 00" N	121° 48' 00" E
33	16° 28' 00" N	121° 48' 00" E
34	16° 28' 00" N	121° 45' 00" E
35	16° 24' 00" N	121° 45' 00" E
36	16° 24' 00" N	121° 42' 00" E
37	16° 20' 00" N	121° 42' 00" E
38	16° 20' 00" N	121° 39' 00" E
39	16° 28' 00" N	121° 39' 00" E
40	16° 28' 00" N	121° 36' 00" E
41	16° 36' 00" N	121° 36' 00" E
42	16° 36' 00" N	121° 39' 00" E
43	16° 40' 00" N	121° 39' 00" E
44	16° 40' 00" N	121° 36' 00" E
45	16° 48' 00" N	121° 36' 00" E
46	16° 48' 00" N	121° 33' 00" E
47	16° 52' 00" N	121° 33' 00" E
48	16° 52' 00" N	121° 36' 00" E
AREA = 480,000 Hectares		

Unit 1802, 18th Floor, West Tower, Tektite Towers (formerly Philippine Stock Exchange Centre)
Exchange Road, Ortigas Center, Pasig City, Philippines, 1605
docket@preslawfirm.com
(02) 7219 0016 | 09171281157
www.preslawfirm.com

HLB MANN JUDD
ADVISORY AND ACCOUNTING

14 May 2026

The Board of Directors
Tetragon Energy Limited
Suite 2, Ground Floor
100 Havelock Street
West Perth WA 6005

Dear Board Members

INDEPENDENT LIMITED ASSURANCE REPORT ON THE HISTORICAL FINANCIAL INFORMATION AND PRO FORMA FINANCIAL INFORMATION OF TETRAGON ENERGY LIMITED

Introduction

This Independent Limited Assurance Report ("Report") has been prepared for inclusion in a prospectus to be dated on or around 15 May 2026 ("Prospectus") and issued by Tetragon Energy Limited ("the Company") in relation to the Company's offer of 20,000,000 fully paid ordinary shares in the capital of the Company at an issue price of $0.20 per share to raise $4,000,000 (before costs) ("the Public Offer").

This Report has been included in the Prospectus to assist potential investors and their financial advisers to make an assessment of the financial position and performance of the Company. All amounts are expressed in Australian dollars (unless otherwise stated) and expressions defined in the Prospectus have the same meaning in this Report.

This Report does not address the rights attaching to the shares to be issued in accordance with the Public Offer, nor the risks associated with accepting the Public Offer. HLB Mann Judd ("HLB") has not been requested to consider the prospects for the Company, nor the merits and risks associated with becoming a shareholder, and accordingly has not done so, nor purports to do so. HLB has not made and will not make any recommendation, through the issue of this Report, to potential investors of the Company, as to the merits of the Public Offer and takes no responsibility for any matter or omission in the Prospectus other than the responsibility for this Report.

Further declarations are set out in Section 7 of this Report.

Structure of Report

This Report has been divided into the following sections:

1. Scope of Report;
2. Directors' Responsibility;
3. Our Responsibility;
4. Conclusions;
5. Restriction on Use;
6. Liability; and
7. Declarations.

1. Scope of Report

We have been engaged to perform a limited assurance engagement and to report on the Financial Information as set out in Section 6 of the Prospectus.

This Report has been prepared for inclusion in the Prospectus. HLB disclaims any assumption of responsibility for any reliance on this Report or on the Financial Information to which this Report relates for any purposes other than the purpose for which it was prepared. This Report should be read in conjunction with the Prospectus.

Historical Financial Information

The historical financial information, as set out in Section 6 of the Prospectus, comprises:

- the historical Statement of Profit or Loss and Other Comprehensive Income for the period from the Company's incorporation, 6 February 2025 to 31 March 2026;
- the historical Statement of Cash Flows for the period from the Company's incorporation, 6 February 2025 to 31 March 2026; and
- the historical Statement of Financial Position as at 31 March 2026,

(together the "Historical Financial Information").

The Historical Financial Information has been prepared in accordance with the recognition and measurement principles of Australian Accounting Standards (including the Australian Accounting Interpretations) adopted by the Australian Accounting Standards Board and the Corporations Act. The Historical Financial Information is presented in an abbreviated form insofar as it does not include all the presentation, disclosures, statements or comparative information as required by Australian Accounting Standards applicable to annual financial reports prepared in accordance with the Corporations Act or International Financial Reporting Standards.

Pro Forma Financial Information

The pro forma financial information, as set out in Section 6 of the Prospectus, comprises:

- the Pro Forma Statement of Financial Position of the Group as at 31 March 2026, prepared on the basis that the pro forma adjustments and subsequent events had occurred as at 31 March 2026; and
- the Notes to the Pro Forma Historical Financial Information,

(together, the "Pro Forma Financial Information").

References to "the Group" relate to the Company and its wholly owned subsidiary, Tetragon Energy (Philippines) Pty Ltd.

The Pro Forma Financial Information has been derived from the Historical Financial Information of the Company, after adjusting for the effects of subsequent events adjustments and pro forma adjustments as described in Section 6 of the Prospectus. The stated basis of preparation is the recognition and measurement principles contained in Section 6 of the Prospectus, as if those event(s) or transaction(s) had occurred at 31 March 2026. Due to its nature, the Pro Forma Financial Information does not represent the Group's actual or prospective financial position, financial performance or cash flows.

This Report has been prepared for inclusion in the Prospectus. HLB disclaims any assumption of responsibility for any reliance on this Report or on the Financial Information to which this Report relates for any purpose other than the purposes for which it was prepared. This Report should be read in conjunction with the Prospectus.

2. Directors' Responsibility

The Directors of the Company are responsible for the preparation and presentation of their respective Historical Financial Information and the Pro Forma Financial Information, including the selection and determination of pro forma adjustments made to the Historical Financial Information and included in the Pro Forma Financial Information.

This includes responsibility for such internal controls as the directors determine are necessary to enable the preparation of the Historical Financial Information and Pro Forma Financial Information that are free from material misstatement, whether due to fraud or error.

3. Our Responsibility

Our responsibility is to express a limited assurance conclusion on the Financial Information based on the procedures performed and evidence we have obtained. Our engagement was conducted in accordance with Standard on Assurance Engagements ASAE 3450 *Assurance Engagements involving Corporate Fundraisings and/or Prospective Financial Information*.

A review consists of making enquiries, primarily of persons responsible for financial and accounting matters, and applying analytical and other review procedures. A review is substantially less in scope than an audit conducted in accordance with Australian Auditing Standards and consequently does not enable us to obtain reasonable assurance that we would become aware of all significant matters that might be identified in an audit. Accordingly, we do not express an audit opinion.

Our engagement did not involve updating or reissuing any previously issued audit or review report on any financial information used as a source of the financial information.

In relation to the information presented in this Report:

a) support by another person, corporation or an unrelated entity has not been assumed; and

b) the amounts shown in respect of assets do not purport to be the amounts that would have been realised if the assets were sold at the date of this Report.

4. Conclusions

Historical Financial Information

Based on our review, which was not an audit, nothing has come to our attention that causes us to believe that the Historical Financial Information of the Group, as set out in Section 6 of the Prospectus, is not presented fairly in accordance with the measurement and recognition requirements (but not all of the presentation and disclosure requirements) of applicable Australian Accounting Standards and other mandatory professional reporting requirements.

Pro Forma Financial Information

Based on our review, which was not an audit, nothing has come to our attention that causes us to believe that the Pro Forma Financial Information of the Group as set out in Section 6 of the Prospectus is not presented fairly, in all material respects, with the measurement and recognition requirements (but not all of the presentation and disclosure requirements) of applicable Australian Accounting Standards and other mandatory professional reporting requirements.

5. Restriction on Use

Without modifying our conclusion, we draw attention to Section 6 of the Prospectus, which describes the purpose of the Financial Information, being for inclusion in the Prospectus. As a result, the Financial Information may not be suitable for use for another purpose.

6. Liability

The liability of HLB is limited to the inclusion of this Report in the Prospectus. HLB makes no representation regarding, and has no liability for, any other statements or other material in, or omissions from, the Prospectus.

7. Declarations

a) HLB will be paid its usual professional fees based on time involvement, for the preparation of this Report and review of the Financial Information, which is estimated to be $20,000 plus GST;

b) Apart from the aforementioned fee, neither HLB, nor any of its associates will receive any other benefits, either directly or indirectly, for or in connection with the preparation of this Report;

c) Neither HLB, nor any of its employees or associated persons has any interest in the Company or the promotion of the Company or any of its subsidiaries;

d) HLB Mann Judd are appointed as the Company's auditors;

e) Unless specifically referred to in this Report, or elsewhere in the Prospectus, HLB was not involved in the preparation of any other part of the Prospectus and did not cause the issue of any other part of the Prospectus. Accordingly, HLB makes no representations or warranties as to the completeness or accuracy of the information contained in any other part of the Prospectus; and

f) HLB has consented to the inclusion of this Report in the Prospectus in the form and context in which it appears.

Yours faithfully

HLB Mann Judd
Chartered Accountants

L Di Giallonardo
Partner

www.tetragonenergy.com.au

ACN 684 303 660