Indus Energy NL

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BOARD & MANAGEMENT

Mr Jonathan Whyte
Non-Executive Director
and Company Secretary

Mr Rhys Bradley
Non-Executive Director

Mr Michael Jardine
Non-Executive Director

ABN
22 009 171 046

ASX CODE
IND

ASX Announcement

INDUS TO ACQUIRE NEW ERA OIL AND GAS

26 June 2019

HIGHLIGHTS

- **Indus Energy NL (Indus) and New Era Oil and Gas Pty Ltd (New Era) execute binding Share Sale Agreement to proceed with RTO and re-admission to trading on ASX**
- **Key transaction terms include:**
  - **Indus to issue 100m shares to New Era shareholders in consideration for the acquisition of New Era**
  - **Indus to issue 135m New Options to New Era majority shareholders**
  - **New Era has secured farm-in rights to four attractive exploration & appraisal opportunities within the historically proven & producing Cooper/Eromanga Basin**
  - **Indus to be renamed New Era Oil and Gas NL**
  - **Near-term news flow from drilling on the Bargie Project later in 2019**
  - **Further opportunities identified and being evaluated to add scale post re-listing**
  - **Capital Raising to raise $4m to $5m**
  - **Adelaide Equity Partners appointed as Corporate Adviser and Nascent Capital Partners appointed as Lead Manager to the Capital Raising**
- **Board changes bring a highly experienced Cooper/Eromanga Basin team with a proven track record of success in the region**
- **Notice of Meeting lodged with regulators for review and Prospectus being finalised.**

Summary

As previously advised in October 2018, Indus Energy NL (**Indus** or the **Company**) had entered into a non-binding term sheet to acquire 100% of the issued capital of South Australian based private oil and gas company New Era Oil and Gas Pty Ltd (**New Era**). Indus and New Era have now executed a binding share sale agreement (**SSA**) for the purposes of completing a reverse takeover and Indus/New Era being re-admitted to trading on the ASX (**Acquisition**). A draft Notice of Meeting containing all resolutions required to complete the Acquisition including an Independent Expert's Report (**Notice of Meeting**) will be despatched to Indus shareholders shortly and a Prospectus is currently being finalised.

Subject to shareholder approval Indus will be renamed New Era Oil and Gas NL

New Era has farm-in rights to several oil and gas permits in the Cooper/Eromanga Basin, South West Queensland, Australia (**New Era Projects**). The New Era Board and management includes a team of highly experienced oil and gas professionals who will drive the exploration and development process on the acquisition assets and lead a strategy to grow the Company's asset portfolio. The focus of New Era will be on acquiring further onshore Australian assets, specifically in the Cooper/Eromanga Basin. Details of the New Era Projects and proposed Board and management team are detailed below.

Indus director Jonathan Whyte stated "Indus is very pleased to have reached agreement with New Era on a transaction that, subject to the required approvals and conditions precedent being satisfied, will see the Company re-instated to trading in the near future. At completion the Company will be headed up by a first class technical and corporate management team, led by Mr. Gordon Moseby, who have an intimate knowledge of the Cooper/Eromanga Basin and a track record of exploration success in the region. The Board feel confident that New Era will be able to add scale and build value through both the rapid development of the existing asset portfolio and also through the identification, evaluation and acquisition of additional assets."

OVERVIEW OF NEW ERA PROJECTS

New Era is a privately owned company, which was incorporated in July 2011. It is an upstream hydrocarbon company that was created to identify and secure prospective oil and gas exploration and production projects. New Era has entered into two binding farm-in agreements with experienced exploration and production company Bridgeport Energy (Qld) Pty Ltd (**Bridgeport**), a wholly-owned subsidiary of the New Hope Group of companies.

New Era has assessed and secured four attractive opportunities (covered by two separate farm-in agreements) within the upstream hydrocarbon value chain. These opportunities provide New Era with exposure to projects with a wide range of risk and return metrics within the historically proven and producing Cooper & Eromanga basin sequences. All of these opportunities have been commercially structured to enable New Era to further assess the opportunities through astute expenditure, whilst providing future flexibility to minimise or maximise future exposure as further evaluation results become available.

The first two opportunities are collectively known as the **Bargie Project**. On 23 May 2019, New Era executed a farm-in agreement (the **Bargie Farm-in Agreement**) with Bridgeport to enter into two Joint Ventures: the **Bargie-Glenvale Joint Venture** and the adjacent **ATP 948 Joint Venture.** New Era has the right to earn a participating interest of 30% of each of these Joint Ventures in exchange for funding earn in obligations. Both of these permits are located in the proximity of the Kenmore and Bodalla oil fields on the Eastern flank of the Queensland Cooper/Eromanga Basin.

On 23 May 2019 New Era executed a binding farm-in agreement with Bridgeport to farm-in to ATPs 2023 & 2024 (**2023/2024 Farm-in Agreement**), two under-explored, prospective permits located in the Cooper/Eromanga Basin. The farm-in will allow for New Era to earn up to a 50% participating interest in the permits once granted, with a defined four-year work program. Any expenditure by New Era on ATP 2023 & 2024 is subject to the finalisation of Native Title Agreements for the permits and subsequent granting of the permits to Bridgeport (pending at the date of this announcement).

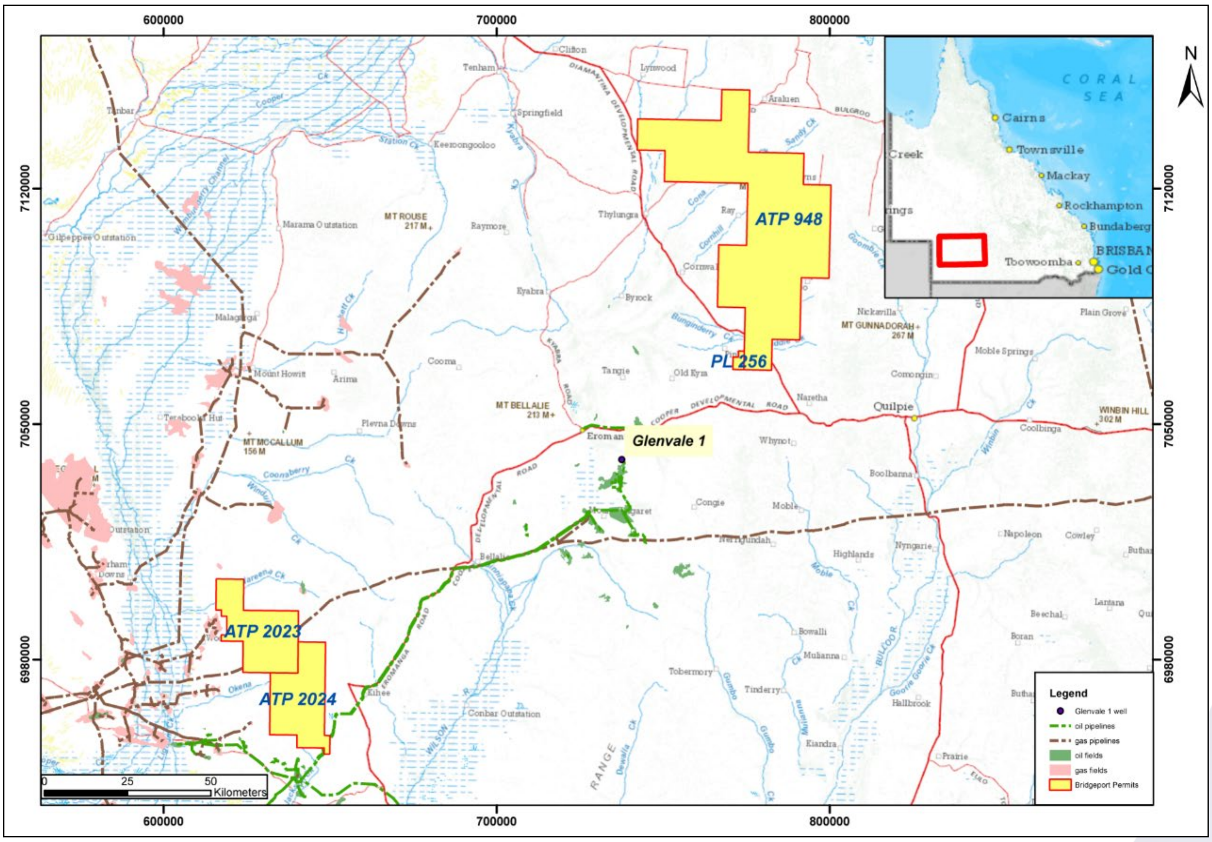

Figure 1: Project location map showing surrounding infrastructure (Source: SRK Consulting)

An Independent Technical Specialist Report containing further details of the Bargie Project and ATPs 2023 & 2024 has also been prepared for inclusion in the Notice of Meeting and an Independent Geologist's Report has been prepared for inclusion in the Prospectus. A copy of that Independent Geologist's Report is attached to this announcement as Schedule 1.

Set out below is a table showing the current reserve and resource estimates for the two projects as set out in the Independent Geologist's Report:

Permit	Field	Gross reserves and Resources (100% Equity)						
		Reserves (Mbbl) (PD+PDNP)			Prospective Resources (Mbbl)			
		1P	2P	3P	Low (P90)	Preferred (P50)	High (P10)	
PL 256	Bargie + Glenvale – 1	17.9	29.9	41.9	81	319	770	As at 31 March 2019
ATP 948	Exploration				1252	4565	16625	As at 31 March 2019
ATP 2023/ ATP2024	Exploration				2800	24700	88500	As at 31 March 2019

Table 1: Current Reserve and Resource Estimates. Mbbl = Thousands of barrels

Refer to the Independent Geologist's Report attached to this announcement as Schedule 1 for further details.

Bargie Project

Key aspects of the Bargie Farm-In Agreement include:

The Bargie Farm-in Agreement provides that, in order to earn a 30% participating interest in the two Joint Ventures, New Era will be required to pay 60% of the cost of drilling a well to a minimum depth of 1,650m to the base of the Basal Jurassic (Poolowanna) stratigraphic formation, up to a maximum of:

- $1,000,000 at the Bargie-Glenvale Joint Venture; and
- $1,060,000 at ATP 948.

Once those maximum amounts have been met, Bridgeport will fund 70% of any excess and New Era will fund the remaining 30% to complete the drilling. Bridgeport will remain as Operator of the permits the subject of the joint venture arrangements, with the location of the well at each permit to be defined by Bridgeport in consultation with New Era following completion of future technical work.

Within 30 days of completing the earning obligations referred to above, New Era will have the right to receive a 30% participating interest in the two Joint Ventures.

A summary of the key terms of the Bargie Farm-in Agreement will be included in the Notice of Meeting.

Key aspects of the Bargie Project include:

- PL 256, contains the Bargie oil field, with a currently suspended producing well awaiting workover (**Bargie-1**), and within which an updip attic appraisal drilling location has been identified through the acquisition and reprocessing of additional modern seismic.

  The existing Bargie-1 well was discovered in the 1990's and has since produced over 170,000 barrels of oil. An opportunity exists to restore this well to production, and produce the remaining reserves, by downhole stimulation and pump repair however this is secondary to the opportunity to drill an appraisal well updip of this existing producer. Significantly the Bargie-1 well is only producing at approximately 50% watercut which, combined with a mapped updip volume, supports the presence of additional recoverable hydrocarbons in the Bargie field.

  The new seismic interpretation has been assessed by independent experts and a resource volume up to 770,000 bbls (P10 gross) has been estimated. New Era will contribute to the drilling of this updip resource volume for the option to earn 30% equity in the production licence. **Figure 2** shows the new mapping of the Bargie field and three locations updip of Bargie-1 producer, of which the Bargie AB location is favoured for the Bargie-5 appraisal well.

- Reserves and production associated with the Glenvale-1 well, which is to the west of PL256 in a different production licence (PL 483) but within the same PL256 Joint Venture.

- The ATP 948 exploration block which abuts the Bargie 256 production licence, and within which have been identified a number of exploration prospects. The new modern seismic which has been acquired in this permit is in the process of being finalised and interpreted to provide the Joint Venture with the best location for drilling the New Era farm-in well. The Operator will conclude this work over the coming months in order to finalise the drilling locations for the October – December 2019 drilling campaign window.

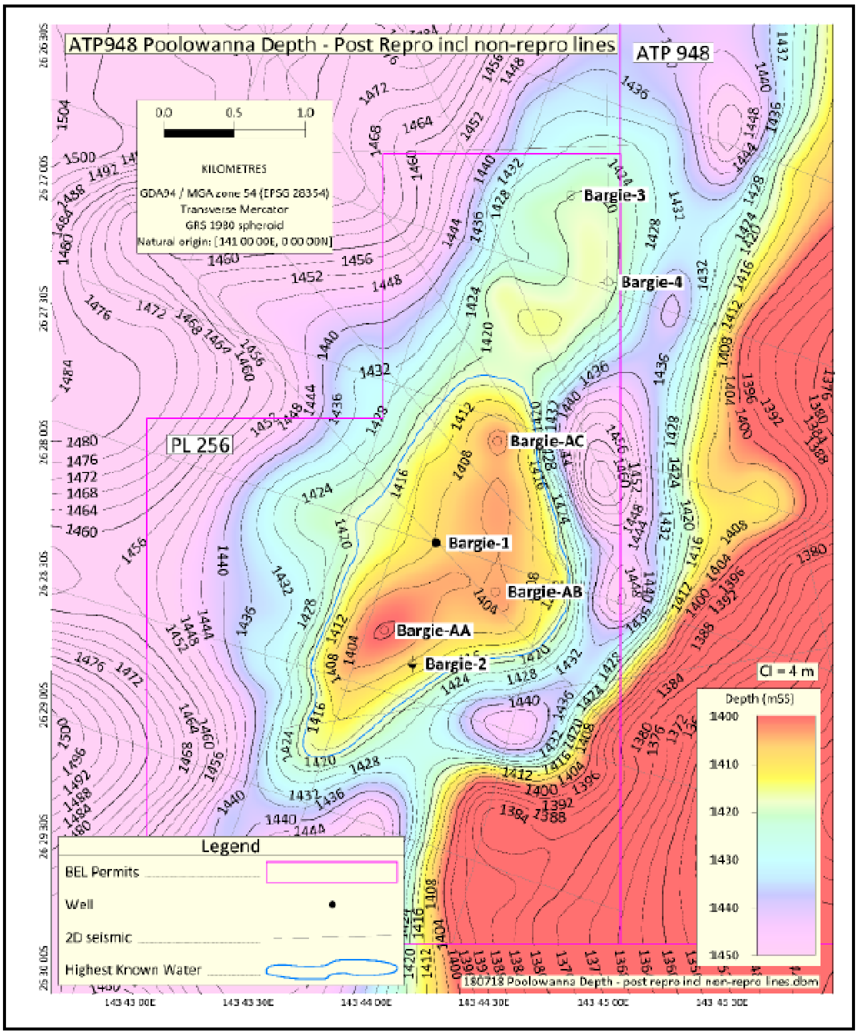

Figure 2: Well locations in Bargie Field Development Plan

ATP 2023 & 2024

Key aspects of the ATP 2023 & 2024 Project and the 2023/2024 Farm-in Agreement include:

- The applications for ATPs 2023 & 2024 are located proximal to numerous existing oil and gas fields to the west and south, including Jackson (Hutton Oil), Ghina (Toolachee gas), Tartulla (Toolachee gas) and Kercummurra (Wyandra Oil). **Figure 3** is an illustration of the proximal historical oil and gas production.

- Analysis of existing seismic data indicates the presence of structures prospective for multiple oil & gas plays. **Figure 4** indicates the prospects currently identified at Hutton (oil) formation level within the blocks. Many structures are also identified at the deeper gas horizons. The considerable prospectivity of these blocks is supported by the large volume of prospective hydrocarbons assessed by the Independent Technical Expert (see Table 1).

- Grant of ATPs 2023 & 2024 is subject to a land access agreement being finalised with relevant native title parties. Bridgeport is currently negotiating the required land access agreement, and New Era expects the agreement and grant to occur shortly.
- Bridgeport will remain as Operator of the all permits the subject of the Bargie and ATP 2023/2024 joint venture arrangements.
- The 2023/2024 Farm-in Agreement allows for New Era to earn up to a 50% interest in the permits, by contributing to the defined four-year work program which includes modern 3D seismic and exploration drilling. Any expenditure by New Era on ATP 2023 & 2024 is subject to the permits being unconditionally granted to Bridgeport (pending at time of this Notice).
- Whilst the entire permit commitments for both blocks would require further funding for New Era, the only obligation for the company is to fund an initial $525,000 for the geological and geophysical review across both blocks in Year 1 of the farm-in. This will enable the company to target future exploration expenditure in a more prudent manner.
- New Era may elect not to proceed into Year 2, or to proceed into Year 2 for one or both blocks. If New Era elects to proceed into Year 2 for either or both of the blocks, it must contribute 50% of the Year 2 work program for a block (with New Era's contribution capped at $2,250,000 per block) to receive an option to acquire an initial 25% interest in the block. To receive the 25% equity New Era will also be required to pay a equity share of past administration and Native Title costs, which are currently undefined (as the Native Title process is incomplete) but are estimated to be less than $100,000 for New Era's 25% equity. New Era will have the option to increase its interest in a block from 25% to 50% by contributing 60% of the Year 3 work program for a block.
- In summary, after the initial $525,000 for the first year, the staged farm-in program enables New Era to earn an interest of 25% to 50% in one or both blocks and is available by spending from $3.3 million (to receive a 25% interest in one of the blocks) up to $9.5 million (to receive a 50% interest in both of the blocks), and exposure to the considerable resource upside within these prospective permits adjacent to existing large Cooper/Eromanga basin discoveries.

A summary of the key terms of the ATP 2023 /2024 Farm-in Agreement entered into with Bridgeport will be included in the Notice of Meeting.

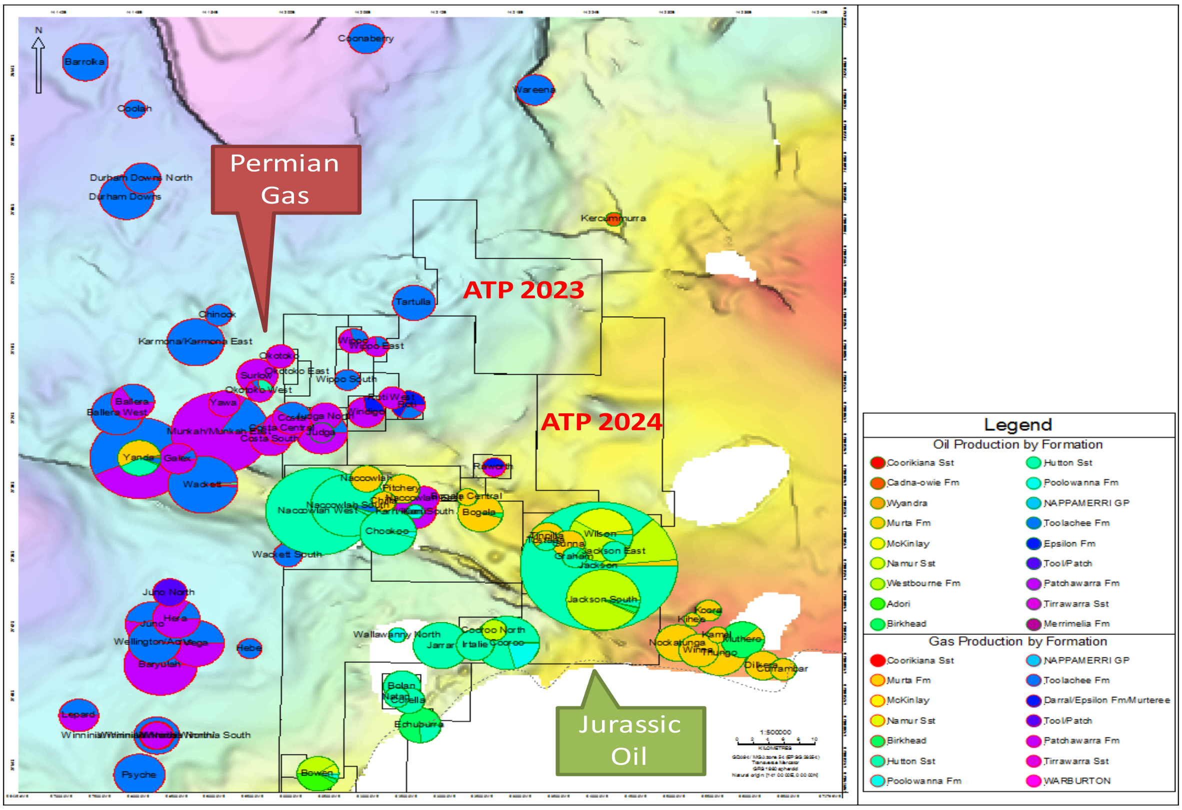

Figure 3: ATP 2023 & ATP 2024 historical production

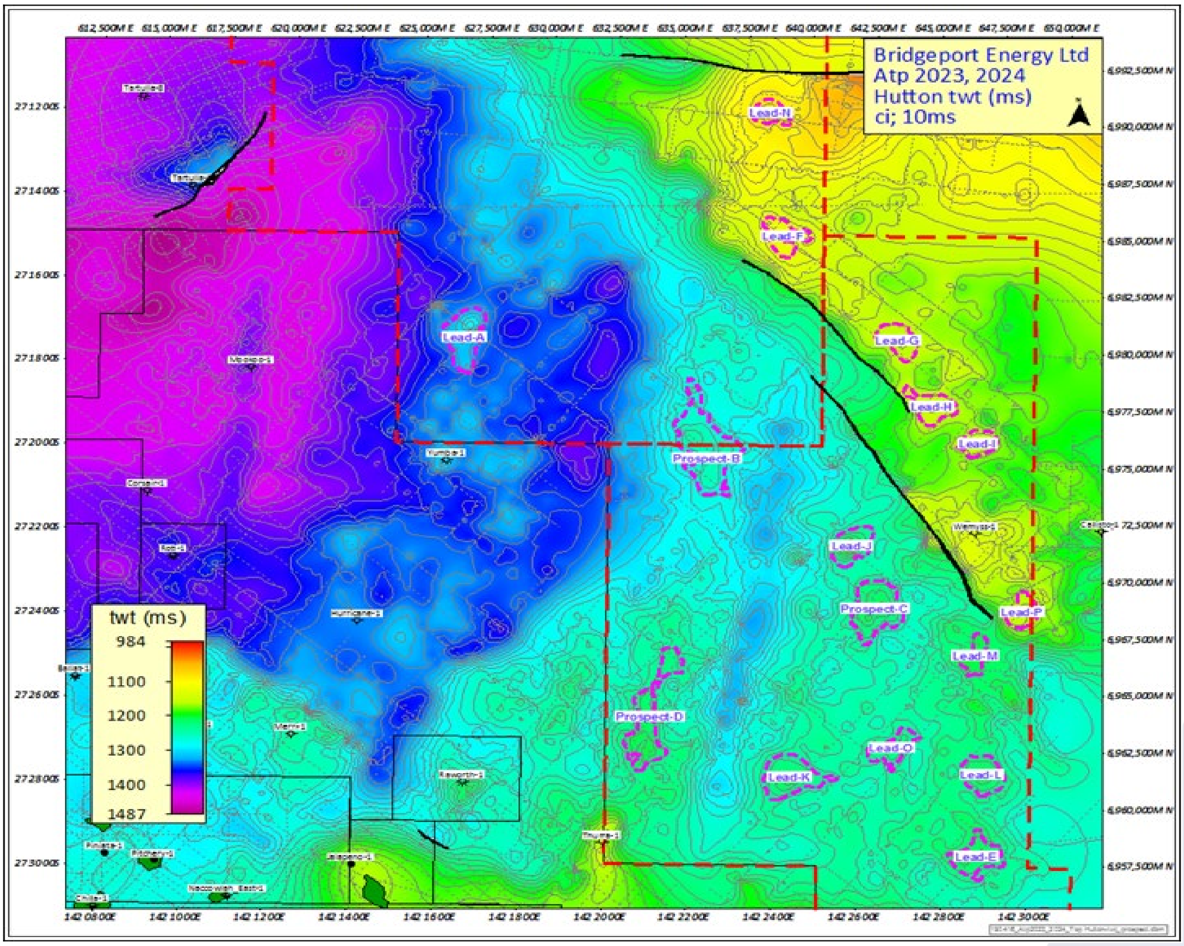

Figure 4: ATP 2023 & ATP 2024 Prospect and Lead Map (Hutton Formation)

CONSOLIDATION

Indus is required to undertake the Consolidation under ASX policy in order to raise equity at less than $0.20 per share. The Notice of Meeting contains a resolution seeking Shareholder approval to consolidate the number of Shares on issue on a 5 for 2 basis, thereby reducing the number of Shares on issue from 165,644,076 to 66,257,630. A timetable for the consolidation will be distributed to Indus shareholders in due course in the Notice of Meeting. Consolidation of Indus' existing share capital was a condition of the ASX waiver referred to below.

KEY TERMS OF THE ACQUISTION

The key terms of the Acquisition are as follows:

(**Consideration**): Subject to shareholder approval, Indus will issue 100,000,000 Shares (on a post-Consolidation basis) to the New Era Shareholders in consideration for the Acquisition.

(**Capital Raising**): Pursuant to the Prospectus, Indus will issue 200,000,000 Shares at an issue price of $0.02 per Share to raise $4,000,000 (before costs) (**Offer**). Oversubscriptions of up to a further 50,000,000 Shares at an issue price of $0.02 per Share to raise up to a further $1,000,000 may be accepted. Indus shareholders will be offered a priority allocation under the Offer.

The Offer will not be underwritten. However, the Company has entered into a mandate for lead manager and corporate advisory services with:

- Nascent Capital Partners Pty Ltd (authorised representative number 415 728) of Nascent Financial Services Pty Ltd (AFSL 402 234) as lead manager; and
- Adelaide Equity Partners Ltd (AFSL 313 143) as corporate advisor.

Provided that the minimum subscription of $4,000,000 (before costs) is achieved, Nascent Capital Partners and Adelaide Equity Partners will receive the following fees for providing those services:

- a management fee of 1% of the gross proceeds raised under the Capital Raising (to be split equally between Nascent Capital Partners and Adelaide Equity Partners); and
- a capital raising fee of 5% of the gross proceeds raised under the Capital Raising (to be split equally between Nascent Capital Partners and Adelaide Equity Partners, after payment of any selling fees payable to third party brokers).

All existing Indus and incoming New Era directors have indicated that they will participate in the Offer.

(**New Options**): Subject to shareholder approval Indus will issue New Options exercisable at $0.04 with an expiry date 3 years from the date of issue to majority New Era Shareholders, comprising:

- 45,000,000 New Options to be issued to Gordon Moseby (as trustee for The ROMM Trust); and
- 45,000,000 New Options to be issued to Icon Holdings Pty Ltd (an entity controlled by Karl Paganin, as trustee for the KJ & AS Family Trust),

as incentives in connection with their appointment as Directors of the Company following (and subject to) completion of the Acquisition; and

- 45,000,000 New Options to Marbel Capital Pty Ltd (an entity controlled by Mark Lindh, as trustee for the M & B Lindh Family Trust) as an introduction and facilitation fee payable in connection with the Acquisition.

(**Conditions Precedent**): Completion of the Acquisition is conditional upon the satisfaction or waiver of the following outstanding conditions precedent:

- each of the New Era Shareholders agreeing to sell their shares in New Era to the Company under the terms of the Acquisition;
- Indus preparing a Prospectus to complete the Capital Raising, lodging the prospectus with ASIC and receiving valid acceptances under the Prospectus totalling $4,000,000 (the **Minimum Subscription**);

- the Company obtaining all necessary shareholder approvals in relation to the Acquisition and to re-comply with the admission and quotation requirements of ASX; and
- the Company obtaining conditional approval for reinstatement of the Company's quoted securities to official quotation on ASX following settlement of the Acquisition.

The SSA also contains a number of indemnities, representations and warranties that are considered standard for an agreement of this nature.

BOARD AND MANAGEMENT CHANGES

On completion of the Acquisition, existing Directors Jonathan Whyte and Rhys Bradley will resign, existing Director Michael Jardine will remain a Director, and three new Directors will be appointed, such that the Board of the Company upon listing on the ASX will be comprised of:

- **Gordon Moseby – (*Managing Director*)**

  Mr Moseby is a petroleum engineer with 25 years' experience in Australasian petroleum basins with a focus on the appraisal, development and production of hydrocarbons (Santos Limited (ASX: STO) (Santos), Oil Search Limited (ASX:OSH), Beach Energy Limited (ASX:BPT) (Beach Energy). Mr Moseby pioneered the Western Flank engineering and production operation capabilities for Beach Energy where the lowest cost operation in the Basin was delivered. Mr Moseby was also involved in the delivery of significant value accretion to early stage development as well as mature assets throughout Beach Energy's Portfolio.

- **Karl Paganin – (*Non-Executive Chairman*)**

  Mr Paganin has over 20 years' experience in investment banking, specialising in transaction structuring, equity and capital markets, M&A and strategic advice to listed companies. He is currently a non-executive director of ASX listed companies Southern Cross Electrical Engineering Limited, Veris Limited and Poseidon Nickel Limited.,

- **Michael Jardine – (*Executive Director, Corporate Development*)**

  Mr Jardine has extensive finance and investment experience across a number of sectors, in both Australia and the UK. Having acted in both executive and board roles for several ASX listed resource companies, Mr Jardine has particular expertise in business development, strategic planning and capital management. Mr Jardine is currently a non-executive director of Indus and also TNT Mines Limited (ASX:TIN).

- **Oliver Foster – (Non-Executive Director)**

  Mr Foster has 20 years of experience as a petroleum geologist, resources analyst and in corporate finance. Mr Fosters oilfield experience was gained working as a petroleum geologist on various exploration and production rigs offshore Australia and Asia. Following this, he spent 10 years as an oil and gas analyst and Executive Director of a boutique Australian natural resources investment bank before moving into energy corporate finance. Mr Foster has significant experience in analysing, marketing and raising equity for various ASX listed energy companies, raising more than $1bn in new equity during his tenure as an analyst. He is the current Commercial Director, and former CEO, of CarbonScape Ltd.

Mr Jonathan Whyte and Mr Rhys Bradley will step down from the Board at the completion of the Acquisition.

PRO-FORMA CAPITAL STRUCTURE

	Minimum Subscription		Maximum Subscription	
	Shares	Options	Shares	Options
Current issued capital	165,644,076	-	165,644,076	-
Consolidation (5:2)	66,257,630	-	66,257,630	-
Issue of Consideration Shares to New Era Shareholders	100,000,000	-	100,000,000	-
Issue of Shares under Capital Raising	200,000,000	-	250,000,000	-
New Options[1]	-	135,000,000[2]	-	135,000,000[2]
Issue of Options to Oliver Foster[3]	-	15,000,000[2]	-	15,000,000[2]
Issue of Shares to Existing Directors[4]	7,500,000	-	7,500,000	-
Issue of Shares to Existing Directors under Salary Sacrifice Program[5]	6,000,000	-	6,000,000	-
Total	**379,757,630**	**150,000,000**	**429,757,630**	**150,000,000**

Notes:

[1] Comprising 45,000,000 New Options to be issued to each of Gordon Moseby (as trustee for The ROMM Trust) and Icon Holdings Pty Ltd (as trustee for the KJ & AS Family Trust), an entity controlled by Karl Paganin, as an incentive in connection with their appointment as Directors of the Company following completion of the Acquisition; and 45,000,000 New Options to be issued to Marbel Capital Pty Ltd (as trustee for the M & B Lindh Family Trust), an entity controlled by Mark Lindh, as an introduction and facilitation fee payable in connection with the Acquisition.

[2] Unlisted Options exercisable at $0.04 (on a post-Consolidation basis) on or before three years from the issue date.

[3] To be issued to Mr Foster as a term of his appointment as a non-executive director of the Company (subject to shareholder approval). Mr Foster's options will be subject to a 2 year service based vesting condition.

[4] To be issued to the existing directors of the Company (subject to shareholder approval) on successful completion of the Acquisition and the Offer in recognition of the additional workload assumed as a result of those transactions.

[5] To be issued to the existing directors of the Company (subject to shareholder approval) under the Company's salary sacrifice programme in lieu of unpaid director fees.

INDICATIVE TIMETABLE

An indicative timetable for completion of the Acquisition and the associated transactions set out in this Notice is set out below:

Event	Date*
Execution of the SSA	26 June 2019
Notice of Meeting for the Acquisition sent to Shareholders	1 July 2019
Lodgement of Prospectus with ASIC	15 July 2019
Opening date of Capital Raising	16 July 2019
Shareholders meeting to approve the Acquisition	31 July 2019
Closing date of Capital Raising	7 August 2019

Event	Date*
Issue of Securities under the Capital Raising Despatch of holding statements	14 August 2019
Re-quotation on ASX	19 August 2019

KEY RISKS

A non-exhaustive list of the key risk factors affecting the Company following completion of the Acquisition and the Offer will be included in the Notice of Meeting.

CHANGE OF COMPANY NAME

Should the Acquisition complete, the Company will undergo a change of name to shareholder approval to **New Era Oil and Gas NL.** A resolution seeking approval for this change of name is included in the Notice of Meeting.

RE-COMPLIANCE WITH CHAPTERS 1 AND 2 OF THE ASX LISTING RULES

The proposed acquisition will result in a change in the Company's nature and scale of its activities and will require shareholder approval under Chapter 11 of the ASX Listing Rules as well as requiring the Company to re-comply with Chapters 1 and 2 of the ASX Listing Rules and obtaining conditional approval from ASX to have its securities re-admitted to trading.

SHAREHOLDER APPROVALS

The Notice of Meeting will be sent to the Company's shareholders in due course. It is expected that the Company will convene a general meeting in late July 2019 to seek shareholder approval for matters in respect of the Acquisition. Those approvals will include:

- the change in nature and scale of the Company's activities;
- the issue of consideration Shares to the New Era shareholders (including Consideration Shares to be issued to related parties of the Company);
- the issue of Shares under the Offer;
- the election of Karl Paganin and Oliver Foster to the Board;
- the consolidation of the Company's capital;
- the change of the Company's name;
- the issue of Shares to related parties;
- the issue of the New Options to the majority New Era Shareholders in connection with the Acquisition (including New Options to be issued to related parties of the Company); and
- the issue of Options to Mr Foster as a term of his appointment as a Non-Executive Director.

The Company's securities have been suspended from quotation on ASX since 3 August 2016 and, subject to shareholder approval being obtained, will remain suspended until the Company has re-complied with Chapters 1 and 2 of the ASX Listing Rules and the Acquisition has completed. If the Company has not been reinstated to quotation by 3 August 2019, ASX policy is that the Company will be removed from ASX. If the Company's shareholders have approved the Acquisition and the Offer, and the Company has lodged the Prospectus in relation to the Offer prior to that date, the Company intends to seek a short 3 month extension from ASX to allow time (if required) to complete the Acquisition and the Offer and re-comply with Chapters 1 and 2 of the ASX Listing Rules. There is no guarantee that ASX will grant that extension.

ASX APPROVALS AND WAIVERS REQUIRED

ASX Listing Rules 1.1 (Condition 12) and 2.1 (Condition 2)

ASX Listing Rule 1.1 (Condition 12) provides that if an entity has options on issue the exercise price for each underlying security must be at least 20 cents in cash. ASX Listing Rules 2.1 (Condition 2) provides that the issue price or sale price of all the securities for which an entity seeks quotation (except options) must be at least 20 cents in cash.

The Company has sought a conditional waiver from the requirements of ASX Listing Rules 1.1 (Condition 12) and 2.1 (Condition 2) to allow the Company to have on issue Options with an exercise price which is less than 20 cents, and to offer Shares under the Prospectus with an issue price which is less than 20 cents. A condition of this waiver was that the Company's share capital be consolidated.

ASX Listing Rules 10.13.3

ASX Listing Rule 10.11 requires a listed company to obtain Shareholder approval by ordinary resolution prior to the issue of equity securities, or agreement to issue equity securities, to a related party of the Company.

ASX Listing Rule 10.13 sets out the requirements for Shareholder approval under ASX Listing Rule 10.11. In particular, ASX Listing Rule 10.13.3 provides that the notice of meeting must (inter alia) state the date by which the entity will issue the securities and that the securities must be issued no later than 1 month after the date of the meeting or such later date as may be permitted by any ASX waiver or modification of the ASX Listing Rules.

The Company has sought a conditional waiver from the requirements of ASX Listing Rule 10.13.3 to allow the Company to issue the Shares to related parties later than 1 month after the date of the General Meeting.

For further information please contact our office on (08) 9380 9920.

Yours Sincerely

The Board of Indus Energy

SCHEDULE 1: INDEPENDENT GEOLOGIST'S REPORT

Independent Geologist's Report on the Petroleum Assets of New Era Oil and Gas Pty Ltd

Prepared for

Indus Energy NL

(To be renamed New Era Oil and Gas NL)

Prepared by

SRK Consulting (Australasia) Pty Ltd

IDS001

June 2019

Independent Geologist's Report on the Petroleum Assets of New Era Oil and Gas Pty Ltd

Indus Energy NL

Unit 32, Level 3
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SRK Project Number: IDS001

June 2019

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Carl D'Silva

26 June 2019

SRK Project No: IDS001

The Company Secretary
Indus Energy NL
Unit 32, Level 3
22 Railway Road
SUBIACO EAST WA 6008

Attention: Mr Jonathan Whyte

Dear Mr Whyte

Independent Geologist's Report on the Petroleum Assets of New Era Oil and Gas Pty Ltd

At the request of Indus Energy NL (Indus), SRK Consulting (Australasia) Pty Ltd (SRK) has reviewed the following four assets, which Indus plans to, acquire for a share consideration in privately owned New Era Oil and Gas Pty Ltd (New Era). SRK has prepared this Independent Geologist's Report (IGR or the Report) for inclusion in Indus' Prospectus (the Prospectus) seeking re-admission to the Australian Securities Exchange (ASX).

New Era has entered into two separate term sheet agreements with Bridgeport Energy (QLD) Pty Ltd (Bridgeport) to farm-in to multiple oil and gas prospects in the prolific Cooper-Eromanga basins of western Queensland, including:

1 A 30% interest in PL (Petroleum Lease) 256 and the Glenvale-1 well
2 A 30% interest in ATP (Authority to Prospect) 948
3 Up to 50% interest in ATP 2023 in two stages; Stage 1 is a 25% interest.
4 Up to 50% interest in ATP 2024 in two stages; Stage 1 is a 25% interest.

Collectively, these permits are known as the "Petroleum Assets" throughout this report. The four petroleum permits are located approximately 970 km west of Brisbane, Queensland.

The objective of this report is to (1) provide an overview of the geological setting of the Petroleum Assets; (2) present a geological description for each project; (3) outline the recent exploration work undertaken on each project; (4) comment on the designed work programs and associated budgets, and (5) comment on the exploration potential of the project areas.

This report has been prepared in accordance with the ASX Listing Rules, under which reporting in accordance with the guidelines of the JORC Code (2012) and VALMIN Code (2015) mineral reporting codes (as defined here within) is required.

The report was compiled by Mr Carl D'Silva, BSc (Hons), MAAPG, MPESA. Mr D'Silva is an Associate Principal Consultant of SRK and experienced in assessing Petroleum Reserves and Resources estimates with over 15 years' relevant experience. Mr D'Silva has adhered to the ASX Listing Rules Guidance Note 32 and his qualifications and experience meet the requirements to act as a Competent Person to report Petroleum Reserves under PRMS (2018) and assess assets under the VALMIN Code (2015). Mr D'Silva consents to the inclusion of this report in Indus' Prospectus based on this information in the form and context in which it appears.

Information basis of this report

For the preparation of this report, SRK's opinion contained herein is based on information provided to SRK by New Era, Indus and Bridgeport throughout the course of SRK's investigations as described in this report, which in turn reflect various technical and economic conditions at the time of writing. SRK has taken such technical information as provided by New Era and Bridgeport in good faith. SRK has not independently verified historical Petroleum Resources estimates by means of recalculation.

This report includes technical information, which requires subsequent calculations to derive subtotals, totals, averages and weighted averages. Such calculations may involve a degree of rounding. Where such rounding occurs, SRK does not consider them to be material.

As far as SRK has been able to ascertain, the information provided by New Era, Indus and Bridgeport was complete and not incorrect, misleading or irrelevant in any material aspect.

Legal matters

SRK notes that it is not qualified to make legal representations with regards to the ownership and legal standing of the Petroleum Assets that are the subject of this report. SRK has not attempted to confirm the legal status of the tenements with respect to acquisition or joint venture (JV) agreements, native title, local heritage or potential environmental or land access restrictions. Instead, SRK has relied on information provided by Bridgeport and New Era. SRK has prepared this report on the understanding that all the tenements of New Era are currently in good standing or pending and that there is no cause to doubt the eventual granting of any tenement applications.

Statement of SRK independence

Neither SRK nor any of the authors of this report have any material present or contingent interest in the outcome of this report, nor do they have any pecuniary or other interest that could be reasonably regarded as being capable of affecting their independence or that of SRK.

SRK is qualified to provide such reports for the purposes of inclusion in public company documents. The Effective Date of the report is 31 May 2019.

SRK has no beneficial interest in the outcome of the technical assessment informing this report being capable of affecting its independence.

Consulting fees

SRK's estimated fee for completing this report is based on its normal professional daily rates plus reimbursement of incidental expenses. The fees are agreed based on the complexity of the assignment, SRK's knowledge of the assets and availability of data. The fee payable to SRK for this engagement exclusive of expenses is estimated at approximately A$15,000. The payment of this professional fee is not contingent upon the outcome of the Prospectus.

Warranties and indemnities

New Era and Bridgeport have confirmed in writing to SRK, that full disclosure has been made of all material information and that to the best of their knowledge and understanding, the information provided by New Era, Indus and Bridgeport was complete, accurate and true and not incorrect, misleading or irrelevant in any material aspect. SRK has no reason to believe that any material facts have been withheld.

As recommended by the VALMIN Code, New Era has provided SRK with an indemnity under which SRK is to be compensated for any liability and/ or any additional work or expenditure resulting from any additional work required:

- which results from SRK's reliance on information provided by New Era and Bridgeport or from New Era not providing material information; or
- which relates to any consequential extension workload through queries, questions or public hearings arising from this report.

Consent

SRK has reviewed the Prospectus and consents to the publication of the reference to the SRK Report in the form and context provided as part of the Independent Geologist's Report and not for any other purpose. SRK provides this consent on the basis that the technical assessments expressed in the Summary and in the individual sections of this report be considered with, and not independently of, the information set out in the complete report and the Cover Letter.

SRK confirms that to the best of its knowledge and belief (having taken all reasonable care to ensure that such is the case), the information contained in the report is in accordance with the facts and does not omit anything likely to affect the import of such information.

SRK confirms that nothing has come to its attention to indicate any material change to what is stated in the report.

Yours faithfully

For and on behalf of SRK Consulting (Australasia) Pty Ltd

Carl D'Silva, *BSc(Hons), MAAPG, MPESA*
Principal Consultant (Petroleum)

Executive Summary

At the request of Indus Energy NL (Indus), SRK Consulting (Australasia) Pty Ltd (SRK) has reviewed the following four assets which Indus plans to acquire in privately owned New Era Oil and Gas Pty Ltd (New Era). New Era has entered into two term sheet agreements with Bridgeport Energy (QLD) Pty Ltd (Bridgeport) to farm-in to multiple oil and gas prospects in the prolific Cooper-Eromanga Basins in south western Queensland.

Collectively, these projects are known as the “Petroleum Assets” throughout this report (Figure ES-1). The four petroleum permits are:

1 A 30% interest in PL (Petroleum Lease) 256 and the Glenvale-1 well

2 A 30% interest in ATP (Authority to Prospect) 948

3 Up to 50% interest in ATP 2023 in two stages; Stage 1 is a 25% interest.

4 Up to 50% interest in ATP 2024 in two stages; Stage 1 is a 25% interest.

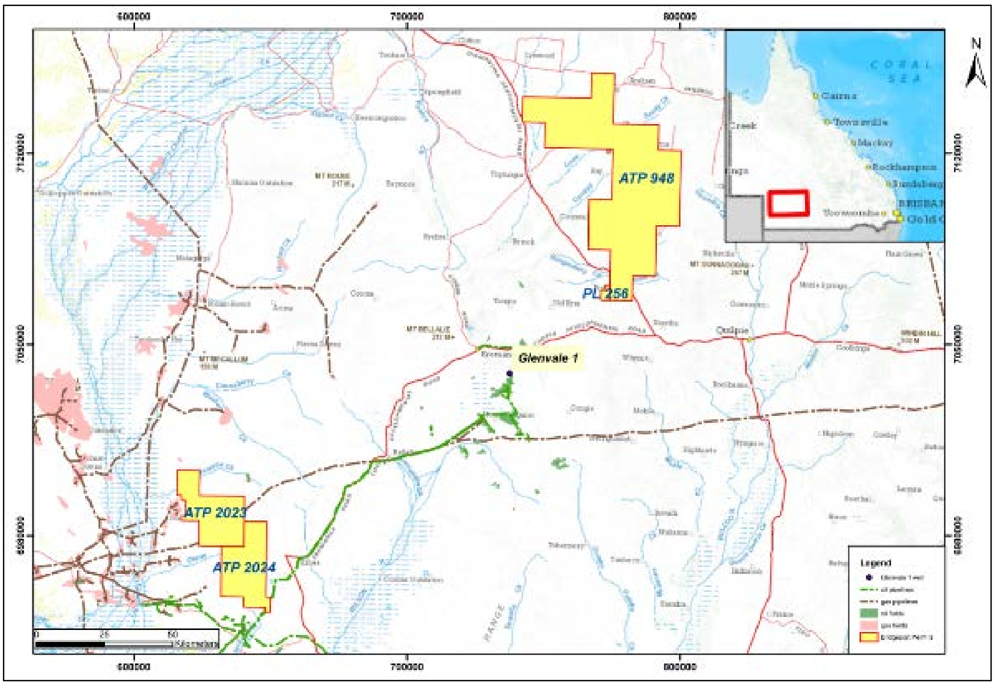

Figure ES-1: Permit location map showing surrounding infrastructure

Source: SRK

It is SRK’s understanding that this Independent Geologist’s Report (IGR) will be included in a Prospectus dated and lodged on or about 15 June 2019, which includes a proposal to acquire the Petroleum Assets subject to shareholder approval and for an offer of up to 200,000,000 shares at an issue price of A$0.02 per share to raise A$4,000,000 (Public Offer). Oversubscriptions of up to a further 50,000,000 shares at an issue price of A$0.02 per share to raise up to a further A$1,000,000 may be accepted.

Petroleum Assets

SRK has previously provided a statement of Petroleum Reserves (1P, 2P, 3P) and Resources within the Bargie and Glenvale Blocks and exploration areas, ATP 948, ATP 2023 and ATP 2024, as part of the Independent Technical Specialist Report (ITSR), incorporating a technical assessment, valuation and statement assessing the proposed plans as at 31 March 2019.

SRK undertook the following work program for the ITSR:

- Assess and compile the available technical data
- Update the 1P, 2P, 3P Petroleum Reserves for the producing Bargie Field and Glenvale-1 well (PL 256)
- Review and audit the technical work undertaken by Bridgeport on the volumetrics of the up-dip potential of the Bargie Field
- Estimate the Petroleum Resource potential of exploration blocks, namely ATP 948, ATP 2023 and ATP 2024.

Based on this work, SRK outlined the following Oil Reserves and Resources within the four permit areas that are the subject of this report, with further details of these assets outlining in the subsequent sections of this report.

Table ES-1: Summary of Reserves and Resources (100% equity basis)

Permit	Field	Gross reserves and Resources (100% equity)						
		Reserves (Mbbl) (PD+PDNP)			Prospective Resources (Mbbl)			
		1P	2P	3P	Low (P90)	Preferred (P50)	High (P10)	
PL 256	Bargie + Glenvale -1	17.9	29.9	41.9	81	319	770	As at 31/03/2019
ATP 2023/ ATP2024	Exploration				2,800	24,700	88,500	As at 31/03/2019

Permit	Field	Gross reserves and Resources (100% equity)						
		Reserves (M BOE) (PD+PDNP)			Prospective Resources (M BOE)			
		1P	2P	3P	Low (P90)	Preferred (P50)	High (P10)	
ATP 948	Exploration				1,252	4,565	16,625	As at 31/03/2019

Source: SRK

Notes:
1. Reserves for Bargie Oil Field have been independently verified by SRK using probabilistic analysis (see additional 3P upside potential in Reserves for Bargie Oil Field).
2. Glenvale-1 well is a single well producer with no field area designated. Glenvale-1 is included as part of the PL 256 Glenvale-Bargie JV. The Glenvale-1 Field Reserves were estimated from decline curve analysis.
3. Potential exists to upgrade Prospective Resources to Undeveloped Contingent Resources following the completion of the 2019 Dayboro reprocessing and volumetric work associated with the up-dip Bargie well location.
4. Reserves/ Prospective Resource volumes were estimated by SRK independent of Bridgeport.
5. ATP 948 – P&L inventory is combination of Hutton oil and Toolachee gas. The conversion factor used was 1boe = 6000 Cubic Feet Gas. The gross prospective numbers for ATP 948 referred above are M BOE rather than M bbl.

PL 256 and ATP 948

SRK reviewed the conceptual project development of targeting the undeveloped reserves (P50 case) within the Bargie Oil Field. Bargie Oil Field development is based on a two-well development scenario – Bargie-5 targeting undeveloped reserves and a second well targeting the remaining Prospective Resource.

Reserves are ascribed to that volume recovered to the date of the economic limit; production beyond that time is classified as Prospective Resource. Economic calculations were determined using the discounted cashflow (DCF) method for the above cases. The techno-economic model inputs comprise future technical production forecasts of developed and undeveloped reserves and forecasts of associated capital and operating costs.

SRK has reviewed the input to the techno-economic models and is satisfied that these are reasonable. SRK has reviewed the sum of cash flows and is satisfied that the models reflect the fiscal terms applying under the respective permits. The model and data inputs have been determined on a 100% asset cashflow basis. The share of reserves of each asset has been determined by the working interest to the recoverable volumes based on the economic cut-off. Oil used for fuel and flare has not been subtracted from reported Reserve volumes.

New Era will earn a 30% participating interest in PL 256 and ATP 948 but will be required to pay 60% of the cost of drilling a well in each permit to a minimum depth of 1,650 m to the base of the Basal Jurassic (Poolowanna) stratigraphic formation, up to a maximum of:

(A) A$1,000,000 at PL 256 (Bargie-Glenvale JV)

(B) A$1,060,000 at ATP 948.

ATP 2023 and ATP 2024

The forward works program for ATP 2023 and ATP 2024 is to acquire 3D (three dimensional) seismic geophysical data to advance the understanding and mitigate risk over currently high-graded leads identified in the permit. SRK considers the work program to be reasonable and appropriate for the continued exploration of the permit.

In total, acquisition of 600 km^2 of 3D seismic surveying in Year 2 work program commitments will increase the Geological Chance of Success (GCOS) by the acquisition of modern 3D seismic data. In terms of funding, New Era's earning obligations and right to participating interest in ATP 2023 and ATP 2024 will occur in two stages:

a) A$525,000 in respect of the Year 1 work program across both permits to earn a 25% working interest.
b) A 50% contribution towards the Year 2 work program (up to a maximum of A$2,250,000 per permit).

New Era intends to fund the initial A$525,000 in respect of the Year 1 work program for geophysical and geological studies. New Era will not be under any obligation to fund the Year 2 earning obligations and will make an assessment as to whether it wishes to do so while the Year 1 work program is in progress. New Era will be required to notify Bridgeport at least 1 month prior to the end of Year 1 whether it intends to proceed with the Year 2 earning obligations.

Proposed budget

The proposed use of funds from the Public Offer in support of the proposed work programs within PL 256, ATP 948, ATP 2023 and ATP 2024 is shown in Table ES-2.

Table ES-2: Proposed use of funds from capital raising

Funds Available / Allocation	Minimum subscription - A$4,000,000	Percentage of funds (%)	Maximum subscription - A$5,000,000	Percentage of funds (%)
Funds Available				
Existing cash reserves of Indus	A$800,000		A$800,000	
Funds raised from the Offer	A$4,000,000		A$5,000,000	
Total	**A$4,800,000**	**100%**	**A$5,800,000**	**100%**
Allocation of Funds				
PL 256 Bargie-5 Appraisal Drilling farm-in	A$1,000,000	20.8%	A$1,000,000	17.2%
ATP 948 Exploration well farm-in	A$1,060,000	22.1%	A$1,060,000	18.3%

ATP 2023 & ATP 2024 studies	A$525,000	10.9%	A$525,000	9.1%
Expenses of the Offer	A$500,000	10.4%	A$460,000	9.8%
Corporate Overheads	A$500,000	10.4%	A$500,000	8.6%
Working Capital	A$1,215,000	25.3%	A$2,250,000	37.0%
Total	**A$4,800,000**	**100%**	**A$5,800,000**	**100%**

Source: New Era Oil and Gas

Within 30 days of completion of all of the earning obligations in all four permits, New Era may either/or:

- Notify all parties of its election to accept an assignment of each of its Farm-in interests (or some of them) including future obligations and liabilities.
- Notify all parties that it does not wish to proceed with an assignment of its Farm-in interest (or some of them) and the Farm-in agreement will terminate with immediate effect (in respect of the relevant Permit) and the parties will each release the other from any further obligations and liabilities.

In SRK's opinion, the use of funds is consistent with the exploration and appraisal opportunities present and the proposed work program. SRK cautions that the Year 2 work programs are dependent on the results achieved in Year 1 and may be different to that initially proposed.

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Disclaimer

The opinions expressed in this Report have been based on the information supplied to SRK Consulting (Australasia) Pty Ltd (SRK) by New Era Oil and Gas Pty Ltd (New Era) and Bridgeport Energy (QLD) Pty Ltd (Bridgeport). The opinions in this Report are provided in response to a specific request from Indus Energy NL (Indus) to do so. SRK has exercised all due care in reviewing the supplied information. While SRK has compared key supplied data with expected values, the accuracy of the results and conclusions from the review are entirely reliant on the accuracy and completeness of the supplied data. SRK does not accept responsibility for any errors or omissions in the supplied information and does not accept any consequential liability arising from commercial decisions or actions resulting from them. Opinions presented in this Report apply to the site conditions and features as they existed at the time of SRK's investigations, and those reasonably foreseeable. These opinions do not necessarily apply to conditions and features that may arise after the date of this Report, about which SRK had no prior knowledge nor had the opportunity to evaluate.

List of Abbreviations

Abbreviation	Meaning
1P	Equivalent to Proved Reserves or Proved in-place quantities, depending on context
2P	The sum of Proved and Probable Reserves or in-place quantities, depending on context
3P	The sum of Proved, Probable and Possible Reserves or in-place quantities, depending on the context
2D	Two-dimensional
A$	Australian dollars
ASX	Australian Securities Exchange
ATP	Authority to Prospect
Bbls	Barrels
BCF	Billions of standard cubic feet
BOE	Barrels of oil equivalent
BOPD	Barrels of oil per day
cc/g	Cubic centimetres per gram
DCF	Discounted cashflow
DNRME	Department of Natural Resources Mines and Energy
DST	Drill stem test
EA	Environmental Authority
EUR	Estimated ultimate recovery
g/cc	Grams per cubic centimetre
GJ	Gigajoules
GCOS	Geological chance of success
IER	Independent Expert Report
IOR	Inland Oil (Production) Pty Ltd
ITSR	Independent Technical Specialist Report
JORC Code	Australasian Code for Reporting of Exploration Reports, Mineral Resources and Ore Reserves prepared by the Joint Ore Reserves Committee of the Australian Institute of Geoscientist and Minerals Council of Australia (JORC), December 2012
kg	Kilograms
km	Kilometres
km^2	Square kilometres
kPa	Kilopascals
LCC	Lowest closing contour
LDP	Later Development Plan
LKG	Lowest known gas
LOLA	Land and Other Legislation Amendment
LPG	Liquid petroleum gas
M	Thousand
MM	Millions
m	Metres

Abbreviation	**Meaning**
1P	Equivalent to Proved Reserves or Proved in-place quantities, depending on context
Ma	Mega-annum (million years)
Mscf/d	Thousands of cubic feet per day
mAHD	Metres (elevation relative to) Australian Height Datum
mD	Millidarcies
MMbbl	Million Barrels
MMboe	Million Barrels of Oil Equivalent
MMcf	Millions of cubic feet
MMcf/d	Millions of cubic feet per day
mSS	Metres sub sea
Mstb	Thousand stock tank barrels
NPV	Net Present Value
NSW	New South Wales
OCA	Oil Company of Australia
OGIIP	Original gas initially in place
OIIL	Oil initially in place
OOIP	Original oil in-place
PHIE	Effective porosity derived from petrophysics
PRMS	Petroleum Resources Management System (PRMS, 2018) issued by Society of Petroleum Engineers, American Association of Petroleum Geologists, World Petroleum Council, Society of Petroleum Evaluation Engineers, Society of Exploration Geophysicists, Society of Petrophysicists and Well Log Analysts and European Association of Geologists and Engineers
PJ	Petajoule
PL	Petroleum Lease
psi/ft	Pounds per square inch per foot
QLD	Queensland
SPE	Society of Petroleum Engineers
SRK	SRK Consulting (Australasia) Pty Ltd
STOIP	Stock tank oil in-place
SWE	Effective water saturation derived from petrophysics
TCF	Trillions of standard cubic feet
US$	US dollar
VALMIN Code	Australasian Code for the Public Reporting of Technical Assessments and Valuations of Mineral Assets 2015
WPC	World Petroleum Council

1 Introduction

At the request of Indus Energy NL (Indus), SRK Consulting (Australasia) Pty Ltd (SRK) has reviewed the following four assets which Indus plans to acquire in privately owned New Era Oil and Gas Pty Ltd (New Era). New Era has entered into two separate term sheet agreements with Bridgeport Energy (QLD) Pty Ltd (Bridgeport) to farm-in to multiple oil and gas prospects in the prolific Cooper-Eromanga basins:

1 A 30% interest in PL (Petroleum Lease) 256 and the Glenvale-1 well

2 A 30% interest in ATP (Authority to Prospect) 948

3 Up to 50% interest in ATP 2023 in two stages; Stage 1 is a 25% interest.

4 Up to 50% interest in ATP 2024 in two stages; Stage 1 is a 25% interest.

Collectively, these projects are known as the “Petroleum Assets” throughout this report. The four petroleum permits are located approximately 970 km west of Brisbane, Queensland, as shown in Figure 1-1. The nearest townships to the New Era permits include Quilpie and Eromanga.

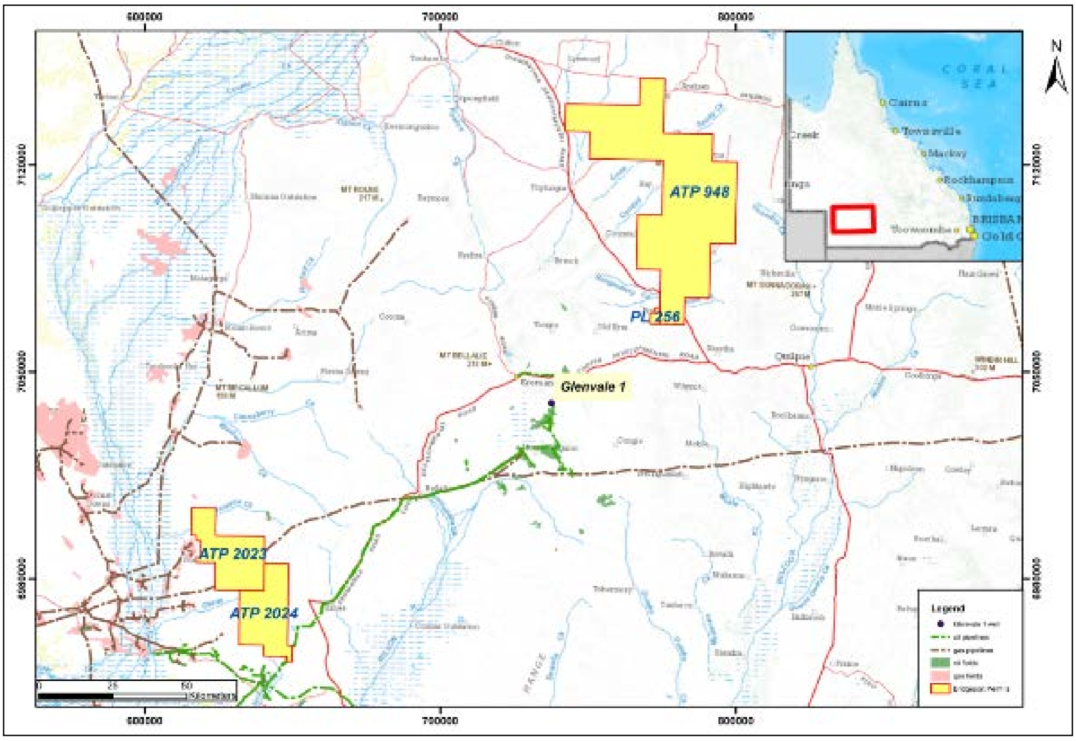

Figure 1-1: Permit location map showing surrounding infrastructure
Source: SRK

1.1 Background

New Era is a privately owned company, which was incorporated in July 2011. It is an upstream hydrocarbon company that was created to identify and secure prospective oil and gas exploration and production projects. New Era has entered into a number of term sheet arrangements with experienced exploration and production company, Bridgeport Energy (QLD) Pty Ltd, a wholly owned subsidiary of the New Hope Group of companies.

Indus Energy NL (ASX: IND) is an Australian public company which has been listed on the Official List of the Australian Securities Exchange (ASX) since February 1987. Most recently, Indus activities have consisted of pursuing acquisition opportunities, predominantly in the resources sector. Indus has been suspended from official quotation since 3 August 2016, as it has been without a significant asset for some time.

As announced on 20 March 2019, Indus entered into a binding share sale agreement with the majority shareholders of New Era (Acquisition Agreement), pursuant to which the Company has agreed to acquire 100% of the issued capital in New Era Oil and Gas Pty Ltd (ACN 152 048 292) (New Era) and completing a backdoor listing of New Era. Indus' current corporate structure is shown in Figure 1-2.

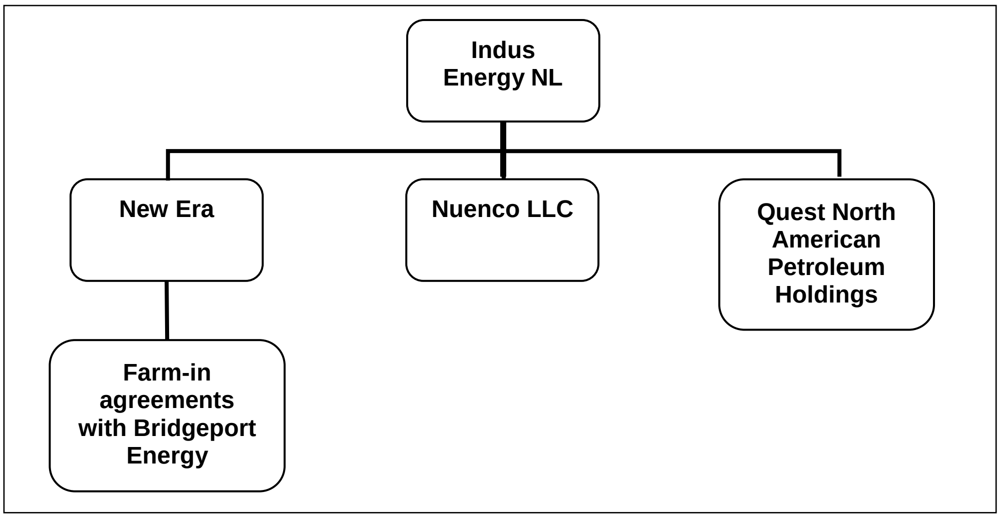

Figure 1-2: Corporate structure of Indus Energy NL
Source: New Era Oil and Gas

The four petroleum assets to be acquired by Indus under the Proposed Transaction are summarised in the following subsections:

- The first two opportunities are collectively known as the Bargie Project. On 25 February 2019, New Era executed a farm-in term sheet agreement with Bridgeport to enter into two joint ventures (JVs) – the Bargie-Glenvale JV and the adjacent ATP 948 JV. New Era has the right to earn a participating interest of 30% of each of these JVs in exchange for funding earn-in obligations. Both permits are located in the proximity of the Kenmore and Bodalla oil fields on the eastern flank of the Cooper-Eromanga basins in southwestern Queensland.
- New Era also finalised an agreement with Bridgeport on 23 May 2019 to farm-in to ATP 2023 and ATP 2024, two under-explored, prospective permits located in the Cooper-Eromanga basins. The farm-in will allow New Era to earn up to a 50% participating interest in the permits, with a defined 4-year work program. Any expenditure by New Era on ATP 2023 and ATP 2024 is subject to the finalisation of Native Title Agreements for the permits and subsequent granting of the permits to Bridgeport (currently pending at date of this report).

It is SRK's understanding that this report will be used in a Prospectus dated and lodged on or about 30 June 2019, which includes a proposal to acquire the Petroleum Assets subject to shareholder approval and for an offer of up to 200,000,000 shares at an issue price of A$0.02 per share to raise A$4,000,000 (Public Offer). Oversubscriptions of up to a further 50,000,000 shares at an issue price of $0.02 per share to raise up to a further A$1,000,000 may be accepted.

1.2 Reporting compliance, reporting standard and reliance

1.2.1 Reporting compliance

This report has been prepared to the standard of, and is considered by SRK to be, an Independent Geologist's Report under the guidelines of the VALMIN Code (2015). It should be noted that the author of this report is a Member of American Association of Petroleum Geologists (AAPG) and Petroleum Exploration Society of Australia (PESA), as such, is bound by both the VALMIN Code and the PRMS Code.

For the avoidance of doubt, this report has been prepared according to:

- 2015 VALMIN edition of the Australasian Code for the Public Reporting of Technical Assessments and Valuations of Mineral Assets (VALMIN, 2015)
- 2018 PRMS and 2011(Guideline) Editions of the Petroleum Resource Management System of the Society of Petroleum Engineers (PRMS, 2011, 2018).

1.2.2 Reliance on SRK

SRK is responsible for this report and declares that it has taken all reasonable care to ensure that the information contained in the report is, to the best of its knowledge, in accordance with the facts and contains no omission likely to affect its import.

SRK considers that its opinion must be considered as a whole and that selecting portions of the analysis or factors considered by it, without considering all factors and analyses together, could create a misleading view of the process underlying the opinions presented in this report. The preparation of a report is a complex process and does not lend itself to partial analysis or summary.

SRK has no obligation or undertaking to advise any person of any development in relation to the Petroleum Assets which comes to its attention after the date of this report or to review, revise or update the report or opinion in respect of any such development occurring after the date of this report and its 'no material change' statement.

1.3 Base technical information, effective date and publication date

The base technical information date, and the Effective Date of the report is 31 May 2019 (the Effective Date). The technical information has been prepared as at the Effective Date. As at the publication date of this report, SRK is not aware that any material change has occurred since the Effective Date. This includes, inter alia, no material changes to the technical information as reported in this report.

1.4 Verification and validation

This report is dependent on technical, financial and legal input. In respect of the technical information as provided by the Company and taken in good faith by SRK, and other than where expressly stated, any figures presented have not been independently verified by means of re-calculation. However, SRK has conducted a review and assessment of all material technical issues likely to influence the technical information included in this report, which included the following:

- SRK reviewed the historical data made available by Bridgeport and New Era in respect of the Petroleum Assets.

- SRK notes that the VALMIN Code (2015) recommends that a site inspection be completed should it be 'likely to reveal information or data that is material to the report'. A site visit was not undertaken for the purposes of this report due to the nature of the assets including exploration permits and single producing well-fields.
- SRK made enquiries of New Era, Indus and Bridgeport's key project and head office personnel, contractors and consultants between April 2019 and May 2019.

Accordingly, Bridgeport and New Era have provided technical data (geological and well information, seismic survey mapping, exploration programs) to SRK for the purpose of this review and inclusion in the report. SRK confirms that it has performed all necessary validation and verification procedures deemed necessary and/ or appropriate by SRK in order to place an appropriate level of reliance on such technical information.

1.5 Limitation, reliance on information, declaration, consent and cautionary statements

1.5.1 Limitations

The technical information supplied to SRK relies on assumptions regarding certain forward-looking statements. These forward-looking statements are estimates and involve a number of risks and uncertainties that could cause actual results to differ materially. The projections as presented and discussed herein have been proposed by New Era's management and cannot be assured. They are necessarily based on economic assumptions, many of which are beyond the control of the Company. Future cashflows and profits derived from such forecasts are inherently uncertain and actual results may be significantly more or less favourable. Unless otherwise expressly stated all the opinions and conclusions expressed in this report are those of SRK.

1.5.2 Statement of SRK independence

Neither SRK, nor any of the authors of this Report, have any material present or contingent interest in the outcome of this Report, nor do they have any pecuniary or other interest that could be reasonably regarded as being capable of affecting their independence or that of SRK.

SRK has no prior association with either New Era or Bridgeport regarding to the petroleum assets that are the subject of this Report. SRK has no beneficial interest in the outcome of the technical assessment being capable of affecting its independence.

Technical Reliance

SRK's opinion contained herein is based on information provided to SRK by New Era and Bridgeport throughout the course of SRK's investigations as described in this report, which in turn reflect various technical and economic conditions at the time of writing. SRK has taken such technical information as provided by New Era and Bridgeport in good faith. SRK has not independently verified historical Petroleum Resources estimates by means of re-calculation.

This report includes technical information, which requires subsequent calculations to derive subtotals, totals, averages and weighted averages. Such calculations may involve a degree of rounding. Where such rounding occurs, SRK does not consider them to be material.

As far as SRK has been able to ascertain, the information provided by New Era and Bridgeport was complete and not incorrect, misleading or irrelevant in any material aspect.

New Era and Bridgeport have confirmed in writing to SRK that full disclosure has been made of all material information and that to the best of their knowledge and understanding, the information provided by New Era and Bridgeport was complete, accurate and true and not incorrect, misleading or irrelevant in any material aspect. SRK has no reason to believe that any material facts have been withheld.

Financial Reliance

In considering all financial aspects relating to the Petroleum Assets, SRK has placed reliance on Bridgeport and New Era that all statutory and regulatory payments [and those due to other third parties] as may be necessary to execute the proposed acquisition and exploration programs is appropriate as at the Effective Date (defined in Section 1.3).

Legal Reliance

In consideration of all legal aspects relating to New Era's Petroleum Assets, SRK has placed reliance on the representations of the Company that the following are correct as of the Effective Date (defined in Section 1.3) and remain correct until the Publication Date (defined below):

- The Company Directors are not aware of any legal proceedings that may have any influence on the rights to explore and develop associated with the Petroleum Assets.
- The legal owners of all mineral and surface rights have been verified.
- No significant legal issue exists which would affect the likely viability of the exploration and production licences as reported herein.

1.5.3 Declaration

Neither SRK nor the persons (as identified in Section 1.7) responsible for authoring this report, nor any Directors of SRK have at the date of this report, nor have had within the previous two years, any shareholding in the Company, the Mineral Assets, or any other economic or beneficial interest (present or contingent) in any of the assets being reported on. SRK is not a group, holding or associated company of the Company. None of SRK's partners or officers are officers or proposed officers of any group, holding or associated company of the Company.

Further, no person involved in the preparation of this report is an officer, employee or proposed officer of the Company or any group, holding or associated company of the Company. Consequently, SRK, the authors and the Directors of SRK consider themselves to be independent of the Company, its directors, senior management and technical consultants.

SRK will receive a fee of A$15,000 for the preparation of this report in accordance with normal professional consulting practices. This fee is not dependent on the findings of this report or the success of the proposed acquisition and SRK will receive no other benefit for the preparation of this report. Neither SRK nor any of the authors have any pecuniary or other interests that could reasonably be regarded as capable of affecting its ability to provide an unbiased opinion in relation to the Mineral Assets.

1.6 Indemnities provided by the Company

As recommended by the VALMIN Code, New Era has provided SRK with an indemnity under which SRK is to be compensated for any liability and/or any additional work or expenditure resulting from any additional work required:

- which results from SRK's reliance on information provided by New Era and Bridgeport or from New Era not providing material information; or

- which relates to any consequential extension workload through queries, questions or public hearings arising from this report.

1.7 Qualifications of Consultants and Competent Persons

The SRK Group comprises over 1,500 staff, offering expertise in a wide range of mining and resource engineering disciplines with 45 offices located on six continents. The SRK Group prides itself on its independence and objectivity in providing clients with resources and advice to assist them in making crucial judgment decisions. For SRK this is assured by the fact that it holds no equity in either client companies/ subsidiaries or petroleum assets.

SRK has a demonstrated track record in undertaking independent assessments of petroleum resources and reserves, project evaluations and audits, Competent Person's Reports, Mineral Resource and Ore Reserve Compliance Audits, Independent Valuation Reports and independent feasibility evaluations to bankable standards on behalf of exploration and mining companies and financial institutions worldwide. SRK has also worked with a large number of major international mining companies and their projects, providing mining industry consultancy service inputs. SRK also has specific experience in commissions of this nature.

This report has been prepared based on a technical and economic review by a team of consultants sourced from SRK's offices in Australia. These consultants have extensive experience in the mining, petroleum and metals sector and are members in good standing of appropriate professional institutions. The consultants comprise specialists in the fields of geology, resource estimation and project evaluation (herein after the "Technical Disciplines").

The report was compiled by Carl D'Silva, BSc(Hons), MAAPG, MPESA. Mr D'Silva is an Associate Principal Consultant of SRK and experienced in assessing Petroleum Reserves and Resources estimates with over 15 years' relevant experience. Mr D'Silva has adhered to the ASX Listing Rules Guidance Note 32 and his qualifications and experience meet the requirements to act as a Competent Person to report Petroleum Reserves under PRMS (2018) and assess assets under the VALMIN Code (2015). Mr D'Silva consents to the inclusion of this report in Indus' acquisition proposal based on this information in the form and context in which it appears.

The Competent Person who has peer reviewed this report is Mr Jeames McKibben, BSc(Hons), MBA, MAusIMM(CP), MAIG, MRICS (Registered Valuer and Chartered Valuation Surveyor), who is a Principal Consultant at SRK's Brisbane office. He is a current member of the VALMIN Code Review Committee. Mr McKibben has 25 years' experience in the mining and metals industry and also has been involved in the preparation of numerous Independent Geologist's Reports comprising technical evaluations of various mineral assets internationally during the past 15 years, which is relevant to the activity which he is undertaking to qualify as a Competent Person as defined in the JORC Code (2012).

Dr. Bruce McConachie, PhD, MAAPG, MPESA, MSPE, MAusIMM also peer reviewed this document. Bruce is a geologist with extensive experience in economic resource evaluation and exploration. His career spans over 35 years and includes production, development and exploration experience in petroleum, coal, bauxite and various industrial minerals, covering petroleum exploration programs, joint venture management, farmin and farmout deals, onshore and offshore operations, field evaluation and development, oil and gas production and economic assessment. His relevant experience includes assessing petroleum Reserves and Resources under the PRMS code (2018) and undertaking mineral and petroleum valuations under the VALMIN (2015) code.

Table 1-1 provides a summary of the key report contributors.

Table 1-1: Summary of responsibilities of key contributors

Competent Persons					
Competent Person	**Position/ Company**	**Responsibility**	**Independent of New Era**	**Date of last site visits**	**Professional designation**
Carl D'Silva	Associate Principal Consultant (Petroleum)/ SRK Consulting (Australasia) Pty Ltd	Overall Report	Yes	None	BSc(Hons),MAAPG, MPESA
Jeames McKibben	Principal Consultant (Project Evaluation)/ SRK Consulting (Australasia) Pty Ltd	Peer Review	Yes	None	BSc(Hons), MBA, MAusIMM(CP), MAIG, MRICS
Dr Bruce McConachie	Associate Principal Consultant/ SRK Consulting (Australasia) Pty Ltd	Technical Peer Review	Yes	None	PhD, MAppSc, BSc, MAusIMM, MAAPG, MSPE, MPESA

2 PL 256 and Glenvale-1 Well

2.1 Location

The Bargie Oil Field (ex ATP 269) is located on the eastern flank of the Cooper-Eromanga basins approximately 970 km west of Brisbane and 38 km northeast of the Bridgeport-operated Kenmore and Bodalla Oil Fields (PL 32). PL 256 covers an area of approximately 15.4 km^2 (Figure 2-1).

The Bargie Oil Field was initially part of ATP 269P JV and was later converted to PL 256 (known as the Glenvale/ Bargie JV). Through a number of changes in operatorship and permit relinquishments, the participants of the permit retained entitlements of Glenvale-1 well. The Glenvale-1 well was drilled by Lasmo Energy Australia Pty Ltd (Lasmo) in September 1986. The well was completed as a single zone Westbourne Formation oil producer. No field area has been designated for this well

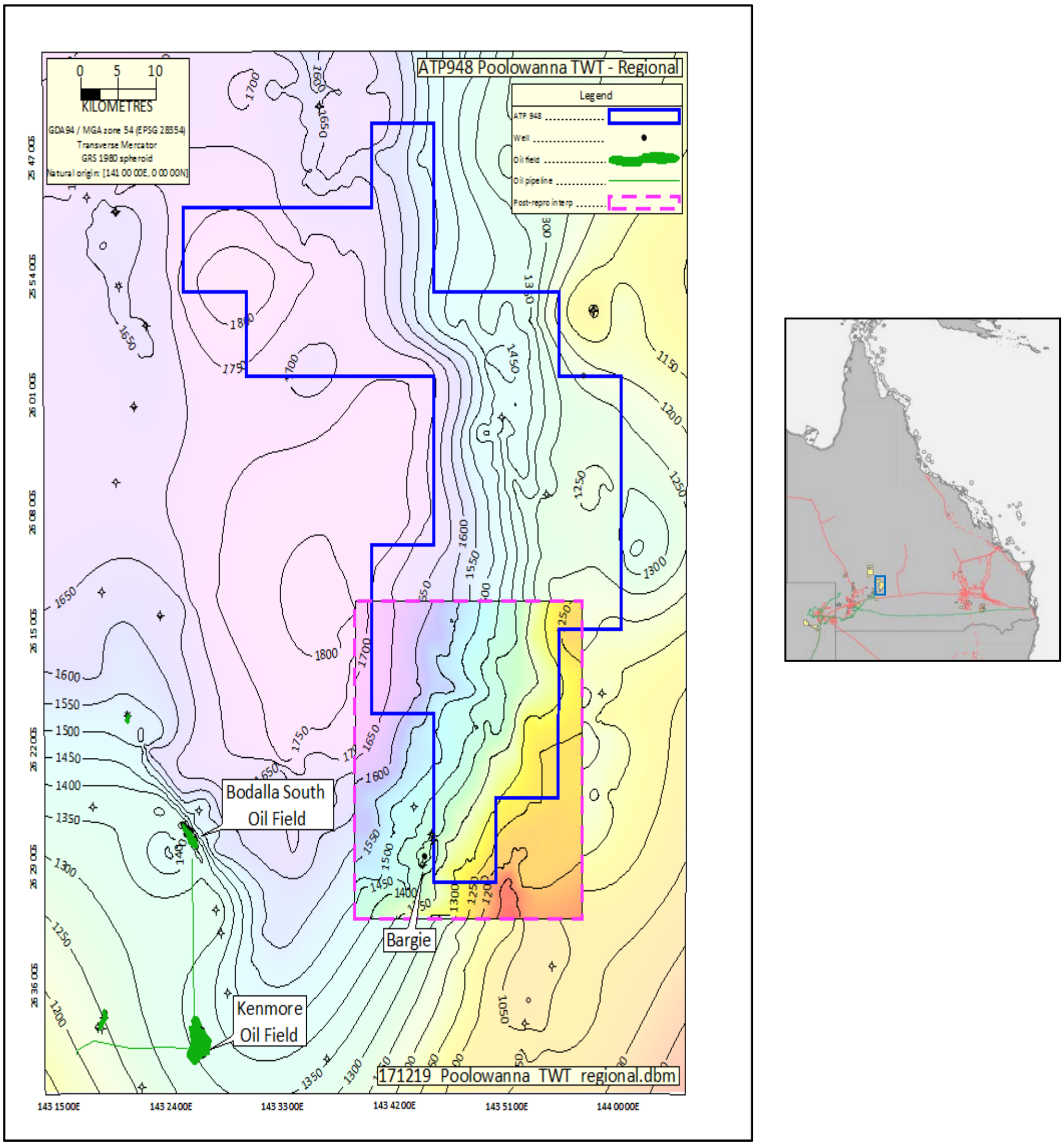

Figure 2-1: PL 256 – Bargie Oil Field with surrounding oil fields

Source: Bridgeport

2.2 Investment rationale

The Cooper Basin is often grouped with the overlying Jurassic–Cretaceous Eromanga Basin and together these form Australia's largest onshore producer of gas and oil from conventional reservoirs. The Cooper-Eromanga basins are Australia's most prolific oil and gas basin and continue to yield new discoveries.

PL 256 contains the Bargie Oil Field, with a currently suspended producer awaiting workover (Bargie-1), and within which an up-dip attic appraisal drilling location has been identified through the acquisition and reprocessing of additional modern seismic geophysical data. The existing Bargie-1 well was discovered in 1994 and has since produced over 177,000 barrels of oil.

An opportunity exists to restore the Bargie-1 well to production, and produce the remaining reserves, by downhole stimulation and pump repair; however, this is secondary to the opportunity to drill an appraisal well up-dip of this existing producer. Significantly, the Bargie-1 well is only producing at approximately 50% water-cut, which combined with a mapped up-dip volume supports the presence of additional recoverable hydrocarbons in the Bargie Oil Field.

New Era has agreed to pay 60% of the cost associated with drilling a well in PL 256 to a minimum depth of 1,650 m in order to intersect the base of the Basal Jurassic (Poolowanna Formation) up to a maximum of A$1.0 million.

2.3 Geology

The Cooper Basin is a Permian to Triassic aged sequence of sediments deposited in a terrestrial fluvial-lacustrine environment. The major source rock units within the Cooper Basin are the Permian aged coals and carbonaceous shales in the Patchawarra and Toolachee formations. Natural gas reservoirs are found in sandstones in multiple formations, including the Patchawarra Formation, Epsilon Formation and Toolachee Formation. The Triassic aged Nappamerri Group sequence provides a regional seal for the Cooper Basin and separates the Cooper Basin from the overlying Eromanga Basin. The Eromanga Basin is Jurassic to Cretaceous in age and is a sequence of sediments varying from fluvial to lacustrine to marine in origin. Oil is commonly found within the high-deliverability sands of the Namur and Hutton sandstone units and within the meandering fluvial, overbank and lacustrine facies which comprise the Poolowanna, Birkhead and Murta Formations. Geochemistry data of surrounding wells shows that the oil is sourced from the underlying Cooper Basin (Figure 2-2).

The Cooper Basin is predominantly gas-producing, with a considerable light liquid hydrocarbon component. By contrast, the overlying Eromanga Basin hosts predominantly liquids that have mostly migrated from the underlying Cooper Basin source kitchen (Boreham & Hill, 1998).

2.4 Exploration history

The Bargie-1 well was completed as a Poolowanna (equivalent to Basal Jurassic) stratigraphy and is the only producer in the field, with a cumulative production of 177.4 Mstb Bbls.

Four wells have been drilled in PL 256 within the Bargie Oil Field (Figure 2-4). Three wells were plugged and abandoned following the intersection of the oil-water contact (OWC) or drilling off-structure (Figure 2-3).

2.5 Permit status and commitments

Bridgeport holds a 93.9% working in PL 256 with Inland Oil (Production) Pty Ltd (IOR) having the residual 6.1% interest. On 25 February 2019, New Era executed a farm-in term sheet agreement with Bridgeport to earn a participating interest of 30% in PL 256 (Bargie) and the Glenvale-1 well in exchange for funding earn-in obligations. Following successful completion of the farm-in obligations, the working interests in the permit will be Bridgeport (63.9%), New Era (30.0%) and IOR (6.1%).

Bridgeport will remain as Operator for these permits. Bridgeport works under a Joint Operating and Production Agreement (effective 5 October 2012) with New Era and IOR. PL 256 was granted under the *Petroleum Act 1923* on 17 April 2014 for a 5-year term expiring on 16 April 2019 (Table 2-1).

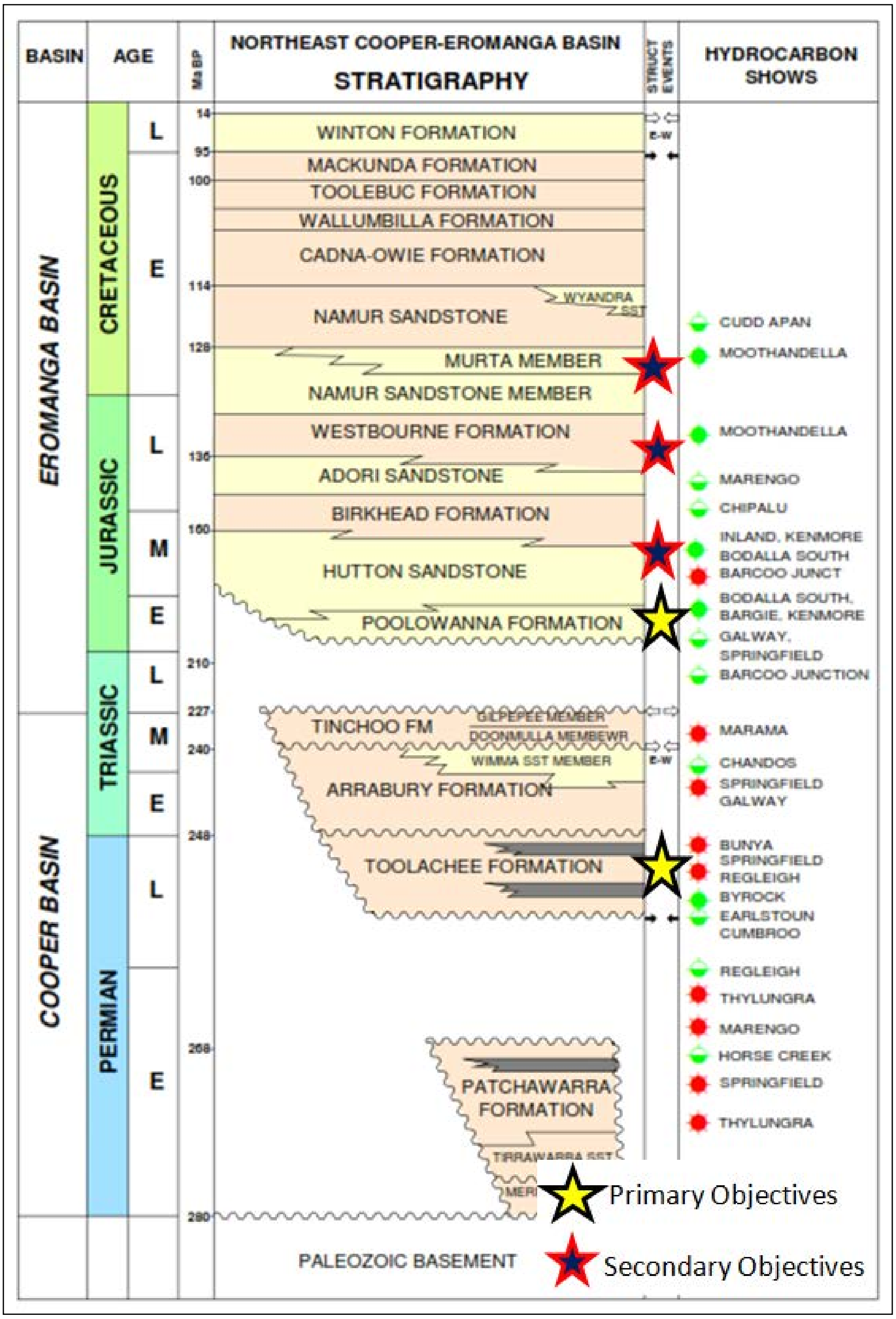

Figure 2-2: Cooper-Eromanga basins stratigraphic column

Source: McKellar, 2013

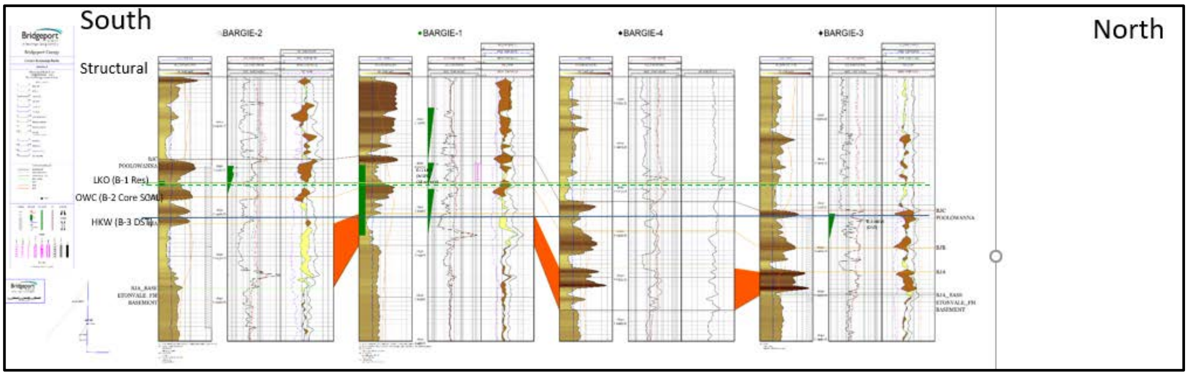

Figure 2-3: Bargie Oil Field Well Section (Bargie-2 to Bargie-1 to Bargie-4 to Bargie-3)

Source: Bridgeport

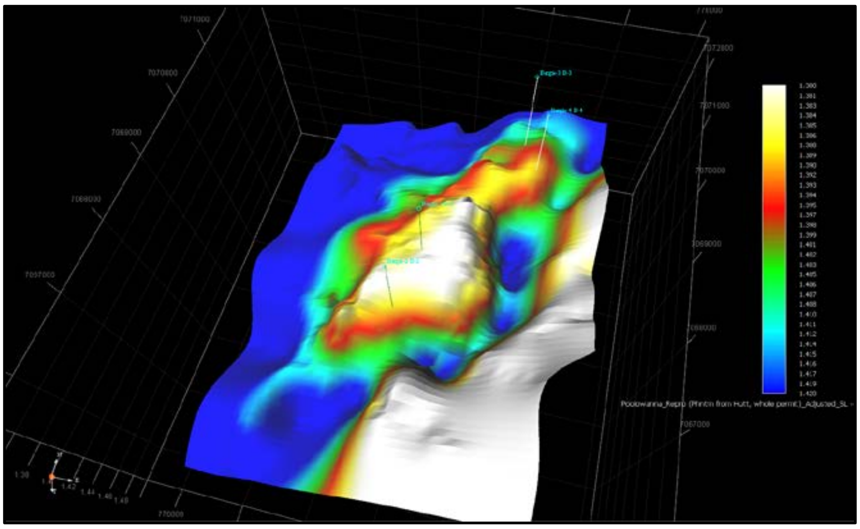

Figure 2-4: Bargie Wells – 3D rendering of Top Poolowanna Structure Map

Source: Bridgeport

Table 2-1: PL 256 work program and commitments

Proposal Later Development Plan (17 April 2019 to 16 April 2024)			
Year	**Proposed activity**	**Location of activity**	**Estimated cost**
2019-2020	Continued production Monitoring and optimisation G, G&E Studies	Bargie-1 – Chemical treatment with Microcure to improve relative permeability to oil	$50,000
2020-2021	Continued production Monitoring and optimisation G, G&E Studies	Bargie-1 – Maintenance on well head and pump rod string as needed	$50,000
2021-2022	Continued production Monitoring and optimisation G, G&E Studies	Bargie-1	$50,000
2022-2023	Continued production Monitoring and optimisation G, G&E Studies	Bargie-1	$50,000
2023-2024	Continued production Monitoring and optimisation G, G&E Studies	Bargie-1	$50,000

Source: Bridgeport

Bridgeport has submitted an Application for Replacement Tenure to the Queensland Department of Natural Resources, Mines and Energy (DNRME), in addition to a Later Development Plan (LDP) and a plan to replace the tenure currently under the *Petroleum Act 1923*, to be replaced with the *Petroleum and Gas Act 2004*. The new title was meant to commence on 17 April 2019 for an additional 5-year term. However, no notification from the DNRME has since been received.

SRK considers this work program to be appropriate for this LDP. To the best of SRK's knowledge, the Queensland Government has allowed the Production Licences in good standing and ongoing production to be extended. Bridgeport has provided SRK with Financial Statements, work plans and budgets for past three financial years.

2.6 Prospectivity

The current field development work program for PL 256 consists of drilling one up-dip appraisal well on the Bargie Oil Field. The proposed well, Bargie-5, will target up to 10 m of up-dip attic appraisal well with more than 1.5 km^2 areal closure up-dip of the producing Bargie-1 well (Figure 2-5).

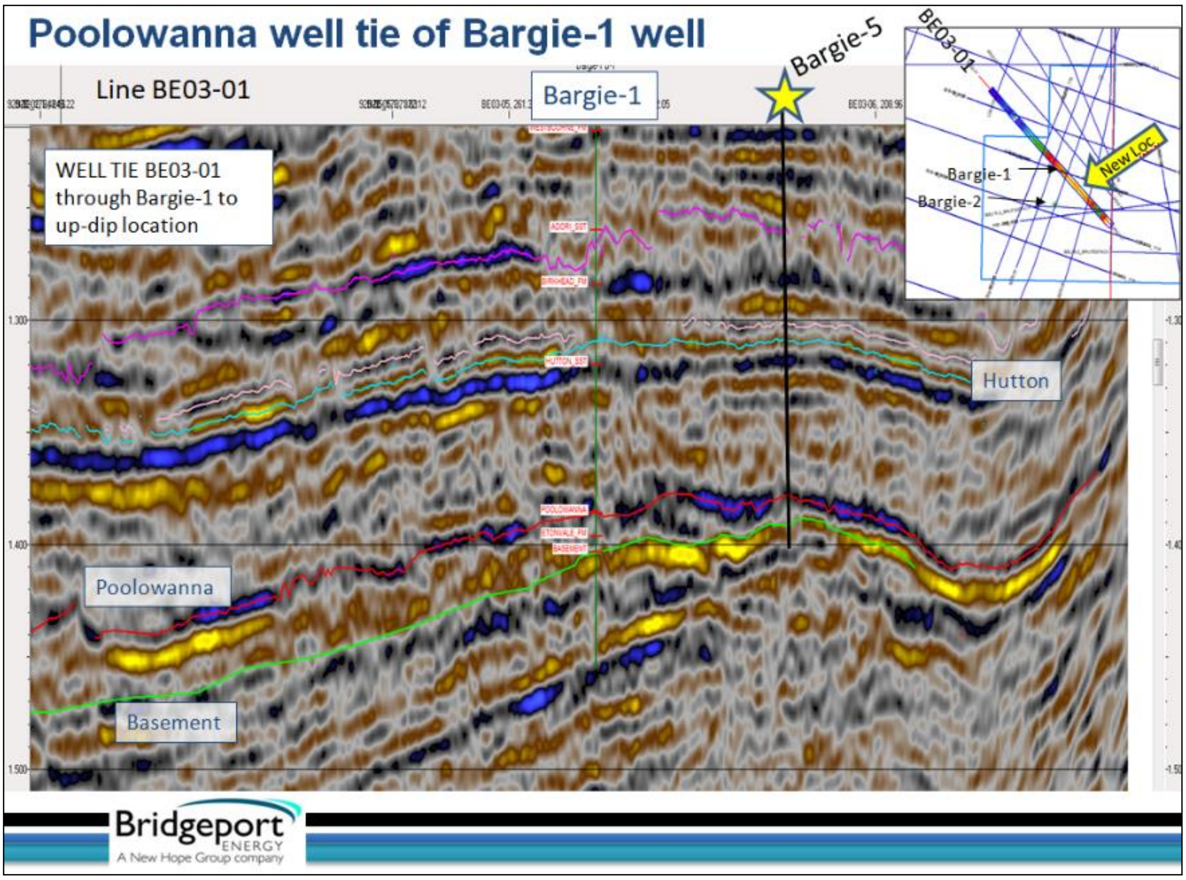

Figure 2-5: Proposed Bargie-5 well location up-dip of Bargie-1 producing well
Source: Bridgeport

The Bargie Oil Field was remapped by Bridgeport in April 2018 using the 2017 reprocessed 2D seismic geophysical and mapping data through interpreting the reprocessed lines and tying the unprocessed lines to the reprocessed set. Using probabilistic analysis, the probability of P1 (1%), 1420 mSS contour was chosen to include the Bargie-3 and Bargie-4 wells due to the chance they were incorrectly drilled. The probability of 10% chance (P10), 1418 mSS contour was chosen based on the highest known water in the Bargie-3 well and the probability of 90% chance (P90) was chosen based on the Bargie-1 contour as a known oil producer (Figure 2-6).

Using volumetric inputs, based on the depth spill point method, petrophysical assumptions, fluid pressure, volume and temperature (PVT) data and a range of recovery factors, SRK has calculated a volume for the crest of the Bargie structure.

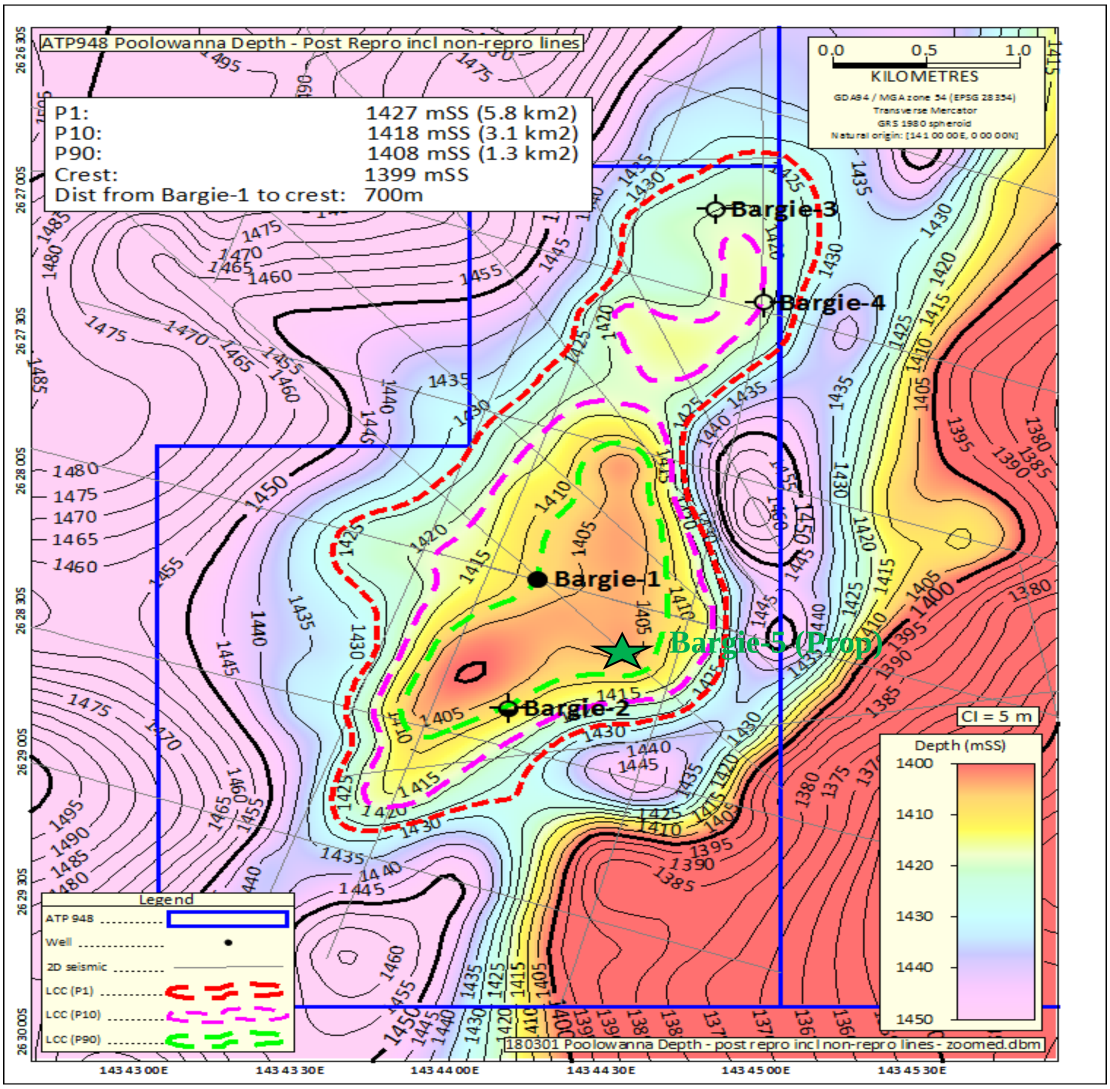

Figure 2-6: Bargie Oil Field – Poolowanna depth structure map (post-2018 reprocessing)
Source: Bridgeport

2.7 Review opinion

The total (1P, 2P, 3P) Reserves for both the Bargie and Glenvale-1 areas are based on decline curve analysis using Val Nav^{TM} software and Excel charts containing historical production data. As the wells have been producing for many years, decline curve analysis was undertaken on a reservoir individual well basis. Each well forecast production has been declined to 1 Bbl/d, which is roughly equal to fuel use.

The Bargie-1 well produced approximately 2.7 BOPD in February 2019 for a cumulative oil production of 177.36 Mstb. The Bargie Oil Field is currently shut-in, awaiting a workover program consisting of a chemical treatment to improve the relative permeability of oil within the wellbore. The historical production and decline curve analysis of Bargie-1 is shown in Figure 2-7.

Similarly, the reservoir performance of the Glenvale-1 well was based on a linear decline analysis to 1 Bbl/day over (Figure 2-8). Currently, the Glenvale-1 well averages 8–10 BOPD with 52.9% water-cut. There is limited geological data available.

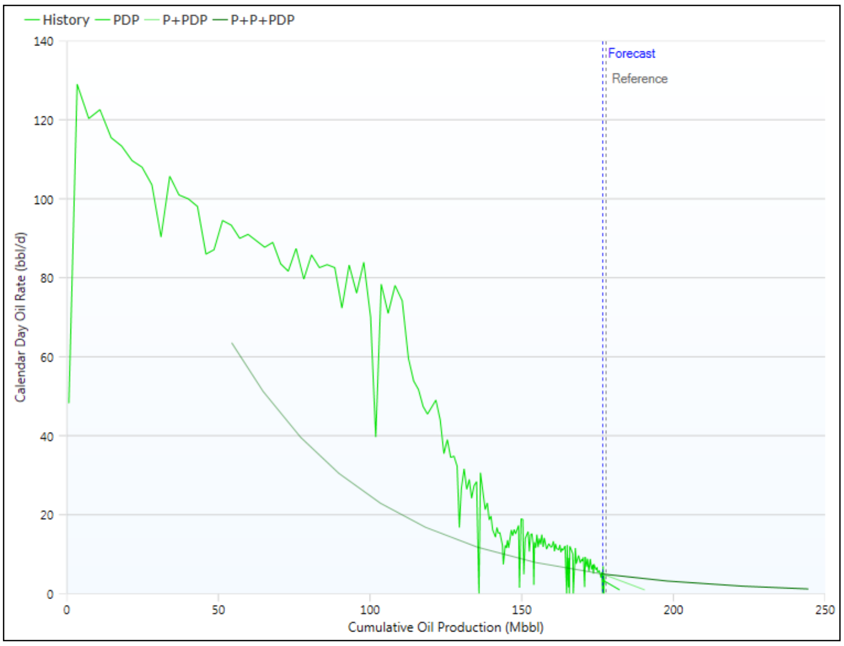

Figure 2-7: Bargie-1 well production forecast (Developed) Reserves

Source: Bridgeport

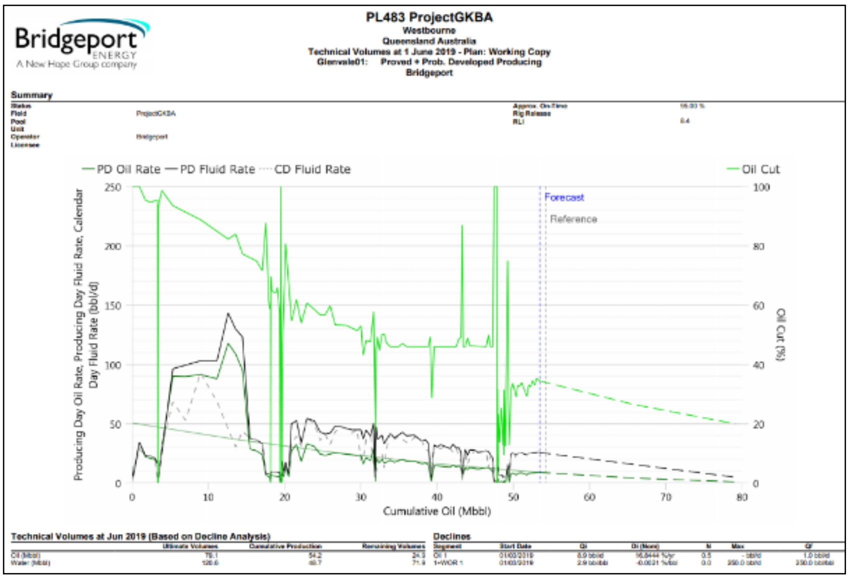

Figure 2-8: Glenvale-1 well production forecast (Developed) Reserves

Source: Bridgeport

SRK considered the upside potential of the existing Bargie structure to be a Prospective Resource and not an “Undeveloped Reserve” that is currently carried internally by Bridgeport. There is potential upgrade of SRK’s Prospective Resources to an Undeveloped Contingent Resource following the completion of the latest geological mapping and reprocessing work. The new geological mapping could identify both a potential for a larger closure area up-dip of Bargie-1 well. SRK independently verified targets by using probabilistic analysis and existing geological mapping of the Bargie structure.

SRK considers that up to two development wells will adequately target the Bargie Oil Field Prospective Resource. A small 3D seismic geophysical survey will better define the up-dip potential and development well locations. The current plan is to drill Bargie-5 on existing 2D (two dimensional) seismic along with the addition of one 2D seismic line from the recent Bargie 2D seismic survey and reprocessing results.

The current Oil Reserves and Prospective Resources in PL 256 are shown in Table 2-2.

Table 2-2: Assessment of Reserves and Resources in PL 256 (Gross & Net to New Era)

Permit	Field	Gross Reserves and Resources (100% Equity)						
		Reserves (Mbbl) (PD+PDNP)			Prospective Resources (Mbbl)			
		1P	2P	3P	Low (P90)	Preferred (P50)	High (P10)	
PL 256	Bargie	14.6	26.6	38.6	81	319	770	As at 31 March 2019
PL 256*	Glenvale-1	3.2	3.2	3.2				As at 31 March 2019
Permit	Field	Net Attributable Reserves and Resources (New Era)						
		Reserves (Mbbl) (PD+PDNP)			Prospective Resources (Mbbl)			
		1P	2P	3P	Low (P90)	Preferred (P50)	High (P10)	
PEL 256*	Bargie + Glenvale-1	5.4	9.0	12.6	24.3	95.7	231	Post Farm-in 30% Equity

Source: SRK analysis

2.8 Field Development review

SRK has considered that a discovery at the Bargie-5 well location would lead to Field Development. The ‘go forward’ costs to put a well online in the Cooper-Eromanga basins in the event of a discovery are about A$200,000. The rest of the field development expenditure would only occur after further evaluation, but a positive discovery means the costs are incrementally small and can be easily managed within the JV with New Era available capital once the A$4.0 million is raised.

SRK has reviewed Bridgeport’s assessment of future recovery and its forecasts and considers that they are classified in accordance with PRMS (2018) and, on aggregate, the remaining volumes are reasonable. Bridgeport and New Era plan to drill the Bargie-5 oil play in late 2019.

3 ATP 948

3.1 Location

ATP 948 is located adjacent to PL 256 and on the north-eastern margin of the Cooper-Eromanga basins in southwest Queensland. ATP 948 is located approximately 85 km northeast of the township of Eromanga within the Quilpie District.

Bridgeport currently holds a 100.0% working interest in ATP 948P.

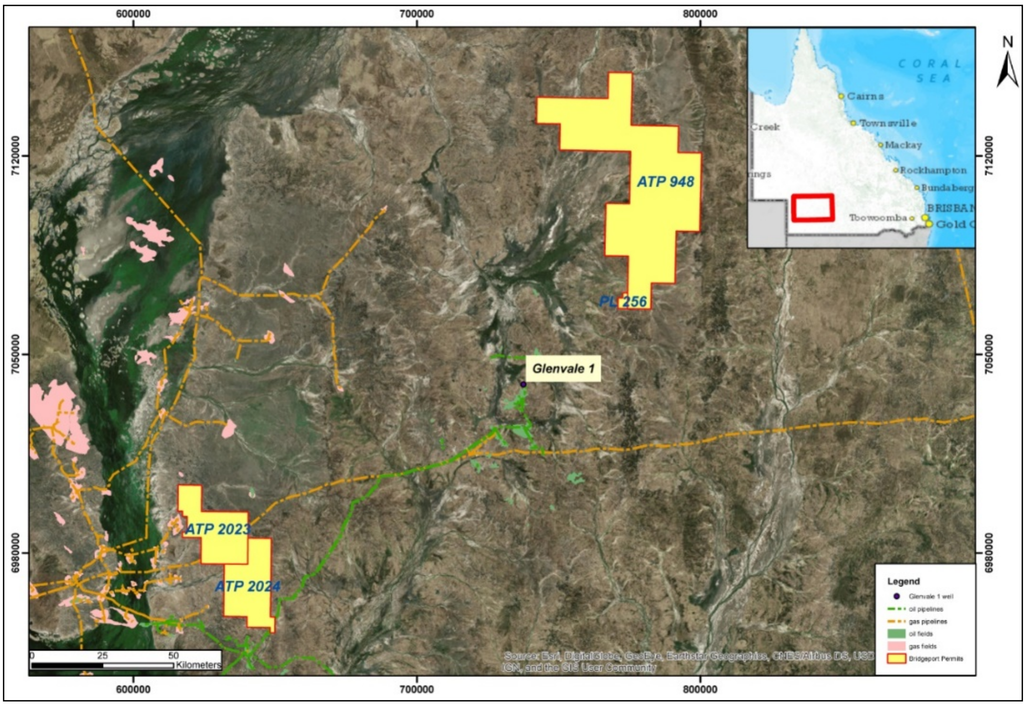

Figure 3-1: ATP 948 location map

Source: SRK

3.2 Investment rationale

New Era will earn up to 30% equity in ATP 948 through an approximately 2:1 promote on drilling one exploration well within ATP 948 to a maximum expenditure cap of A$1.06 million. Upon successful completion of the farm-in obligations, the working interests in the permit would be Bridgeport (70.0%), and New Era (30.0%).

Further development of the Bargie Oil Field along the Triassic and Permian edge will improve prospectivity of nearby leads along the same trend extending into ATP 948. Targeting gas plays in the Permian Patchawarra and oil in the Toolachee Formation inside the edge of the regionally sealing Nappamerri Formation are also attractive targets.

The new 2D seismic geophysical data acquired in August 2018 is in the process of being finalised and interpreted to provide the JV with the best location for drilling the New Era farm-in well. Bridgeport will conclude this work over the coming months in order to finalise the drilling location for the September–November 2019 drilling campaign window. The areal extent of ATP 948 exceeds 2,000 km^2 and provides significant scope for follow-up exploration and opportunity for large discoveries to be made.

The permit is in general proximity of existing oil and gas fields, enabling tie-back to existing infrastructure in the event of a discovery being made.

3.3 Geology

ATP 948 is located on the southern end of the Canaway Ridge on the Permian edge of the Cooper-Eromanga basins (Figure 3-2). PL 256 and ATP 948 share similar geology with source rocks that are mature close to both permits.

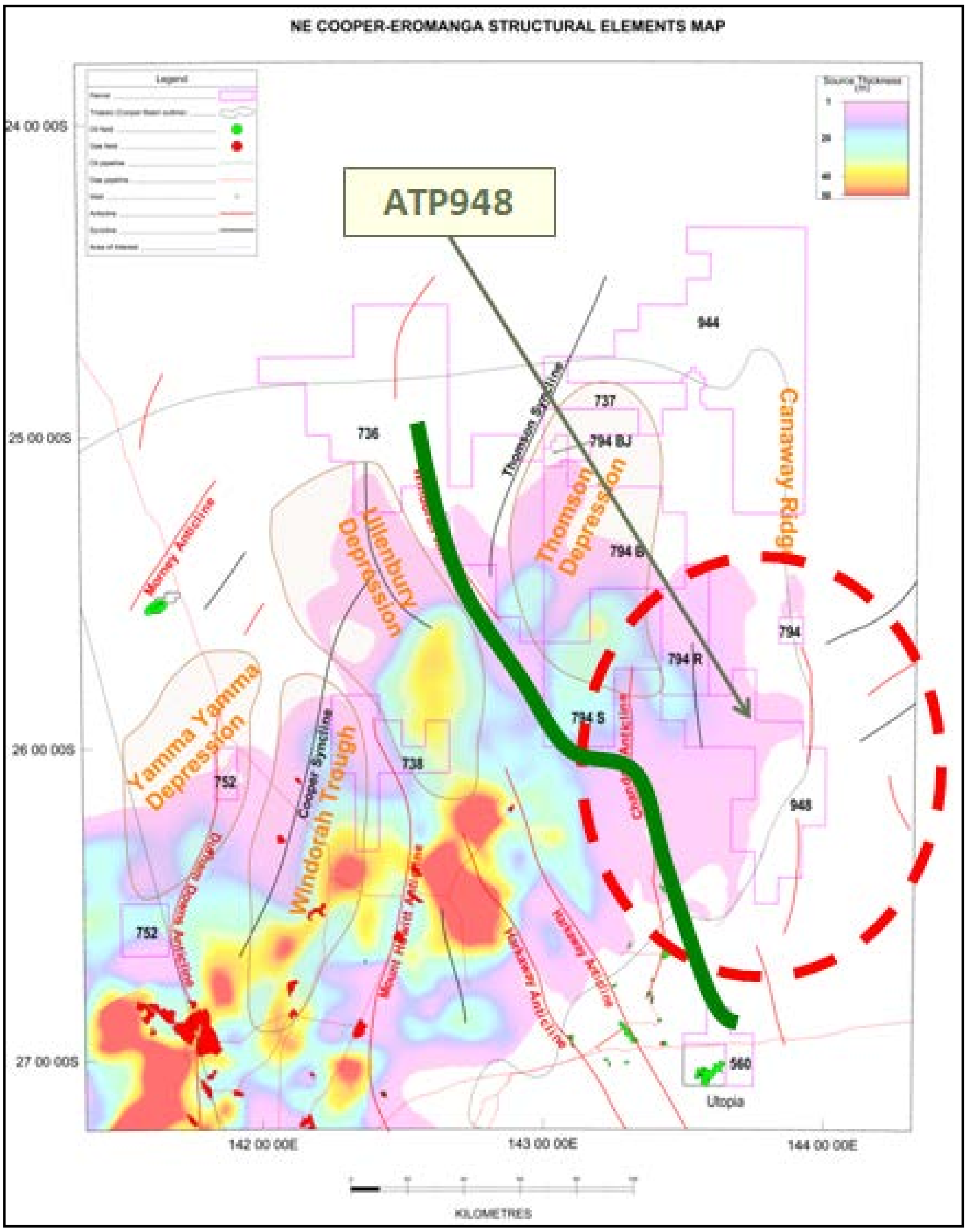

Figure 3-2: Regional structural elements within ATP 948

Source: Bridgeport

3.4 Exploration history

Three wells (Opal-1, Ray-1 and Canaway Downs-2) have been drilled to date in ATP 948, with numerous vintages of 2D seismic data recorded across the permit area (Figure 3-3). A total of 1,550 km of 2D seismic data is available for geological mapping.

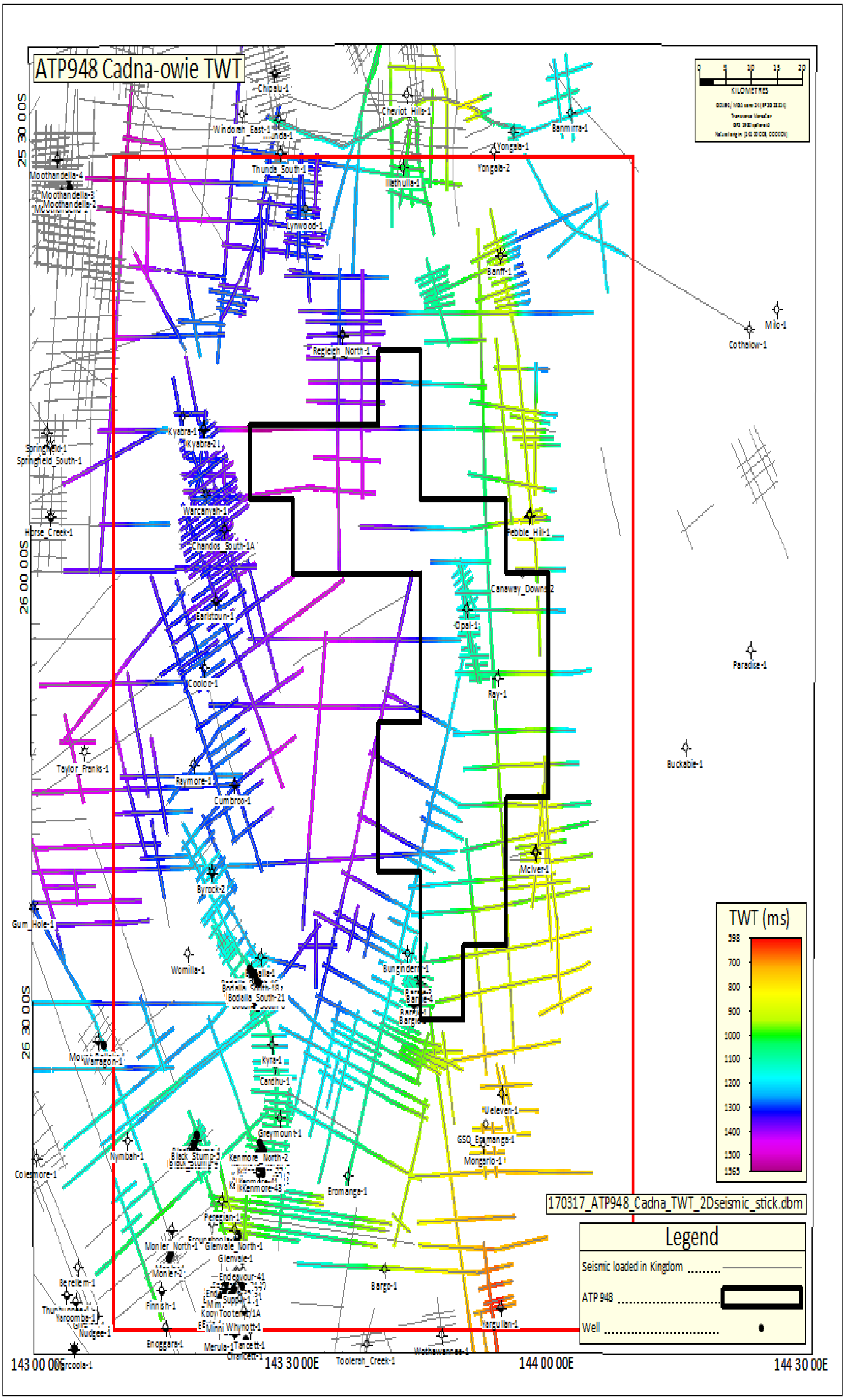

Figure 3-3: Regional wells and 2D seismic data in ATP 948

Source: SRK

3.5 Permit status and commitments

ATP 948 is currently in Year 2 of the permit cycle and the permit has been extended by two years through the *Land and Other Legislation Amendment (LOLA) Bill 2014* to 31 May 2020 by the Queensland Government (Table 3-1). To date, Bridgeport has completed the reprocessing work and also acquired 100 km of 2D seismic geophysical data within ATP 948 in November 2018.

Under the terms of tenure, there is a one-well drilling commitment that remains outstanding that New Era intends to farm-in and meet the work commitment requirements. Bridgeport will be submitting a request for a 'Special Amendment' or 'Variation of Work Commitments' to the DNRME (Petroleum Assessment Hub) to reduce the three-well commitment down to one well. Bridgeport will also commit to including the deferring two wells in this period to the subsequent years, i.e. 1 June 2020 to 31 May 2022.

Table 3-1: ATP 948 work program and commitments

ATP 948 Initial Period (1 June 2014 – 31 May 2020 LOLA)			100%
Year	**Work program**	**Estimated cost ($)**	**Net cost ($)**
Year 1 (ending 31/05/2017)	1,780 km 2D seismic reprocessing	500,000	500,000
Year 2 (ending 31/05/2018)	Acquire 100 km 2D seismic + drill 1 well	2,600,000	2,600,000
Year 3 (ending 31/05/2019)	Drill 1 well	1,600,000	1,600,000
Year 4 (ending 31/05/2020)	Drill 1 well	1,600,000	1,600,000
Total		**6,300,000**	**6,300,000**

Source: Bridgeport

While SRK cannot predict how the discussions with DNRME will progress, having a farm-in partner (New Era) commit to drilling of one well in ATP 948 in this permit year should promote Bridgeport's chances of being successful in future discussions with DNRME.

3.6 Prospectivity

There are two exploration play styles currently present within ATP 948 namely:

a) Oil reservoir in the basal Jurassic Poolowanna Formation in anticlinal traps analogous to the nearby Bargie Oil Field located only 1.3 km from the southwest corner of ATP948

b) Gas in the Permian Patchawarra and oil in the Toolachee Formation inside the edge of the regionally sealing Nappamerri Formation. Oil and gas have been found in wells to the west of ATP 948, with ~10,000 Bbls produced from the Toolachee Formation in Byrock-2 well and a Drill Stem Test (DST) in the Toolachee Formation at the Bunya-2 well of 6.0 mmcfd.

Bridgeport has identified seven prospects and leads (Figure 3-4) on the existing 2D seismic mapping. A 100 km 2D seismic program was recently undertaken by Bridgeport to define the trap size and shape for Lead 1 and Lead 3 to enable them to become drillable targets.

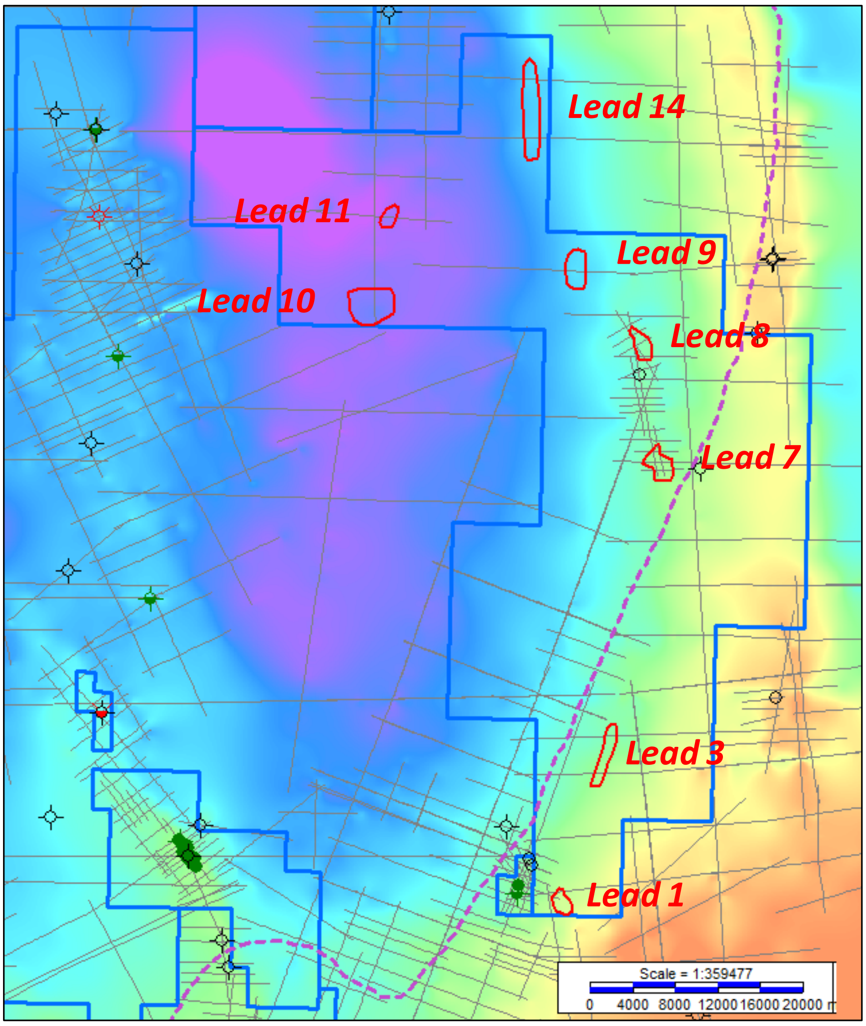

Figure 3-4: Leads identified in ATP 948
Source: Bridgeport

3.7 Review opinion

Initial exploration focus on the Poolowanna leads provides the best potential in ATP 948, with other plays to follow which could potentially emulate the western flank success from other operators working in the Cooper-Eromanga Basin. There are a wide range of P50 Recoverable Poolowanna volumes ranging from 0.4 MM Bbls to 0.88 MM Bbls with a geological chance of success (GCOS) ranging from 16% to 22%. Similarly, the P50 Recoverable Toolachee gas in-place volumes range from 0.98 Bcf to 5.13 Bcf (Table 3-2).

The lowest risk opportunities in ATP 948 lie on trend with the Bargie Oil Field. Lead 1 is closest to the Bargie Oil Field and has been significantly de-risked (with the highest GCOS) with the recent seismic acquisition and reprocessing work undertaken by Bridgeport. Both Lead 1 and Lead 3 are drill-ready candidates.

In SRK's opinion, the Prospective Resources are reasonable and have been prepared in accordance with the definitions and guidelines contained within the Petroleum Resource Management System (PRMS) and generally accepted petroleum engineering and evaluation principles set out in the SPE Reserves Auditing Standards. An extract of the PRMS definitions is included in Appendix A.

SRK's examination included an assessment of the classification and categorisation of the Prospective Resources. SRK's methods incorporated a range of uncertainty to allow the assignment of Low (P90), Best (P50) and High (P10) Prospective Resource categories in accordance with the PRMS (Table 3-3).

Table 3-2: Assessment of Prospect and Lead Inventory in ATP 948

		Poolowanna OIIP (MM bbls) Toolachee GIP (bcf)			Recoverable Poolowanna OIIP (MM bbls) Recoverable Toolachee GIP (bcf)					Risk				
Name	**Formation**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**	**Pmean**	**P90/P10**	**Trap**	**Seal**	**Reservoir**	**Charge**	**GCOS**
Lead 1	Poolowanna	0.59	2.13	7.44	0.11	0.43	1.57	0.71	0.07	0.5	0.9	0.7	0.7	22%
Lead 3	Poolowanna	0.58	2.35	9.18	0.11	0.47	1.93	0.85	0.05	0.4	0.9	0.7	0.6	15%
Lead 7	Poolowanna	1.16	4.44	16.5	0.22	0.88	3.49	1.62	0.06	0.5	0.9	0.7	0.5	16%
Lead 8	Poolowanna	0.57	2.38	9.52	0.11	0.47	2.01	0.87	0.05	0.5	0.9	0.7	0.5	16%
Lead 9	Toolachee	1.09	3.79	13.2	0.67	2.39	8.53	3.87	0.08	0.4	0.9	0.4	0.7	10%
Lead 10	Toolachee	2.63	8.21	25.4	1.62	5.13	16.2	7.63	0.1	0.4	0.9	0.4	0.7	10%
Lead 11	Toolachee	0.47	1.57	5.2	0.28	0.98	3.32	1.53	0.08	0.4	0.9	0.4	0.7	10%
Lead 14	Toolachee	2.66	8.54	27.4	1.64	5.39	17.7	8.21	0.09	0.4	0.9	0.4	0.7	10%
	TOTAL - OIL	**2.90**	**11.30**	**42.64**	**0.55**	**2.25**	**9.00**							**17%**
	TOTAL - GAS	**6.85**	**22.11**	**71.20**	**4.21**	**13.89**	**45.75**							**10%**

Table 3-3: Assessment of Prospective Resources in ATP 948 (Gross & Net to New Era)

Permit	**Field**	**Gross Reserves and Resources (100% Equity)**						
		Reserves (Mbbl) (PD+PDNP)			**Prospective Resources (M BOE)**			
		1P	**2P**	**3P**	**Low (P90)**	**Preferred (P50)**	**High (P10)**	
ATP 948	Exploration				1252	4565	16625	As at 31 March 2019
Permit	**Field**	**Net Attributable Reserves and Resources (New Era)**						**Report by**
		Reserves (Mbbl) (PD+PDNP)			**Prospective Resources (M BOE)**			
		1P	**2P**	**3P**	**P90**	**P50**	**P10**	
ATP 948	Exploration				376	1370	4988	Post Farm-in 30% Equity

Source: SRK analysis

Notes:

1. Volumes reported are 100% gross equity and net entitlement to New Era for ATP 948.
2. SRK agrees with the GCOS estimates by Bridgeport.
3. Estimates are in accordance with the Petroleum Resources Management System (SPE, 2007) and Guidelines for Application of the PRMS (SPE, 2011).
4. Probabilistic methods were used.
5. Original gas in-place (OGIP) excludes shrinkage and fuel
6. Conversion Factor of Toolachee Gas used 1 BOE = 6000 Cubic Feet of Gas. Hence all number reported for ATP 948 are M BOE

4 ATP 2023 and ATP 2024

4.1 Location

Both ATP 2023 and ATP 2024 are located 100 km southwest of Eromanga in the Windorah Trough. There are numerous known oil and gas fields situated to the south and west of the permit areas. These include Jackson Field (Hutton - oil), Ghina (Toolachee - gas), Tartulla (Toolachee - gas) and Kercummurra (Wyandra - oil). The primary targets for ATP 2023 and ATP 2024 include Permian gas within the Toolachee Formation and Jurassic oil with the Hutton Formation (Figure 4-1).

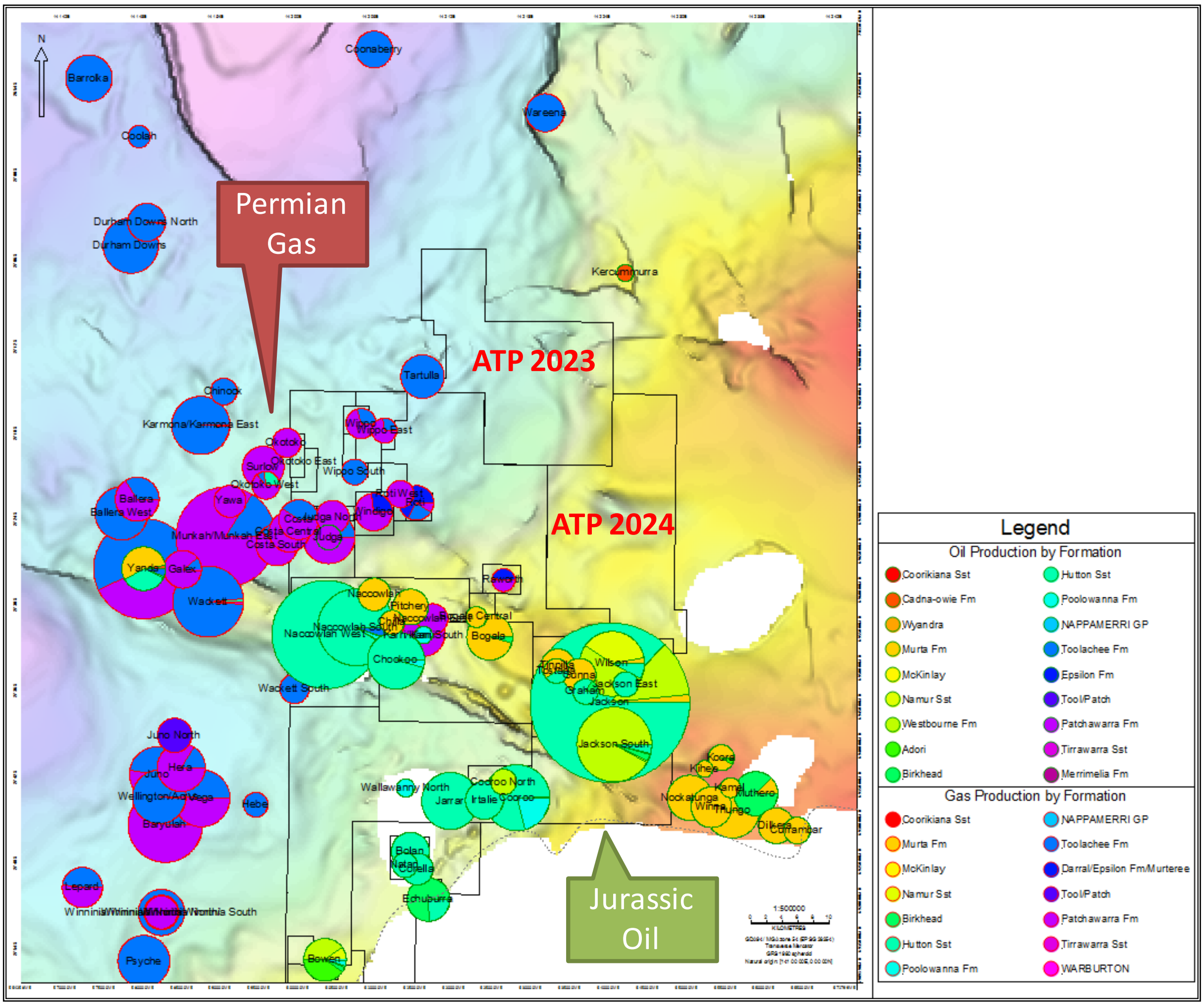

Figure 4-1: ATP 2023 and ATP 2024 historical production bubble map by Formation

Source: Bridgeport

4.2 Investment rationale

New Era is also finalising an agreement with Bridgeport to farm-in to ATP 2023 and ATP 2024, two under-explored, early stages prospective exploration permits located in the Cooper-Eromanga basins. The farm-in will allow New Era to earn up to a 50% participating interest in the permits, with a defined 4-year work program.

Any expenditure by New Era on ATP 2023 and ATP 2024 is subject to the finalisation of Native Title Agreements for the permits and subsequent granting of the permits to Bridgeport (currently pending grant).

4.3 Geology

The primary geological plays in ATP 2023 and ATP 2024 include Jurassic oil plays within the Murta Formation and Hutton Formation primarily set along the Jackson-Naccowlah-Wackett Fault Margin set in structural traps within ATP 2024. Additional targets present include Toolachee Gas potential in ATP 2023, where the Nappamerri Formation thickens to provide a regional seal.

4.4 Exploration history

No wells have been drilled in ATP 2023. Three wells – Wemyss-1, Thurra-1 and Thurra-2 – were previously drilled in ATP 2024 between 1984 and 1992 (Table 4-1). Seismic geophysical data over the two permits includes a grid of vintage 2D seismic data across both permit areas. There is a good coverage of 2D seismic data in ATP 2023 and the northern portion of ATP 2024. The seismic data coverage becomes sparse at the southern end of ATP 2024.

The North Naccowlah 3D and Naccowlah-Jackson 3D seismic surveys both finish at the western edge of the permit boundaries (Figure 4-2).

Table 4-1: ATP 2024 existing wells

Well	Resource	Type	Drilled year	Total depth (m)	Operator	Shows
Wemyss-1	Conventional	Exploration	1988	1848.6	Delhi Petroleum Pty Ltd	• 40-50% fluor at Top Hutton Sst, water saturated • Trace to 20% shows in Namur, Westbourne, Adori and Birkhead
Thurra-1	Conventional	Exploration	1984	2118.4	Delhi Petroleum Pty Ltd	• Cadna-owie and Adori - Trace to 10% fluor • Birkhead - Tr- 15% fluor in thin poor quality Sst near base • Hutton - Tr-10% shows through fm. Porosity in top thin Sst 15-17%, Sw 100% • Patchawarra - Top 6 m had trace shows
Thurra-2	Conventional	Exploration	1992	1830.0	Santos Limited	• No fluor observed in any formation and gas values remained low

Source: SRK

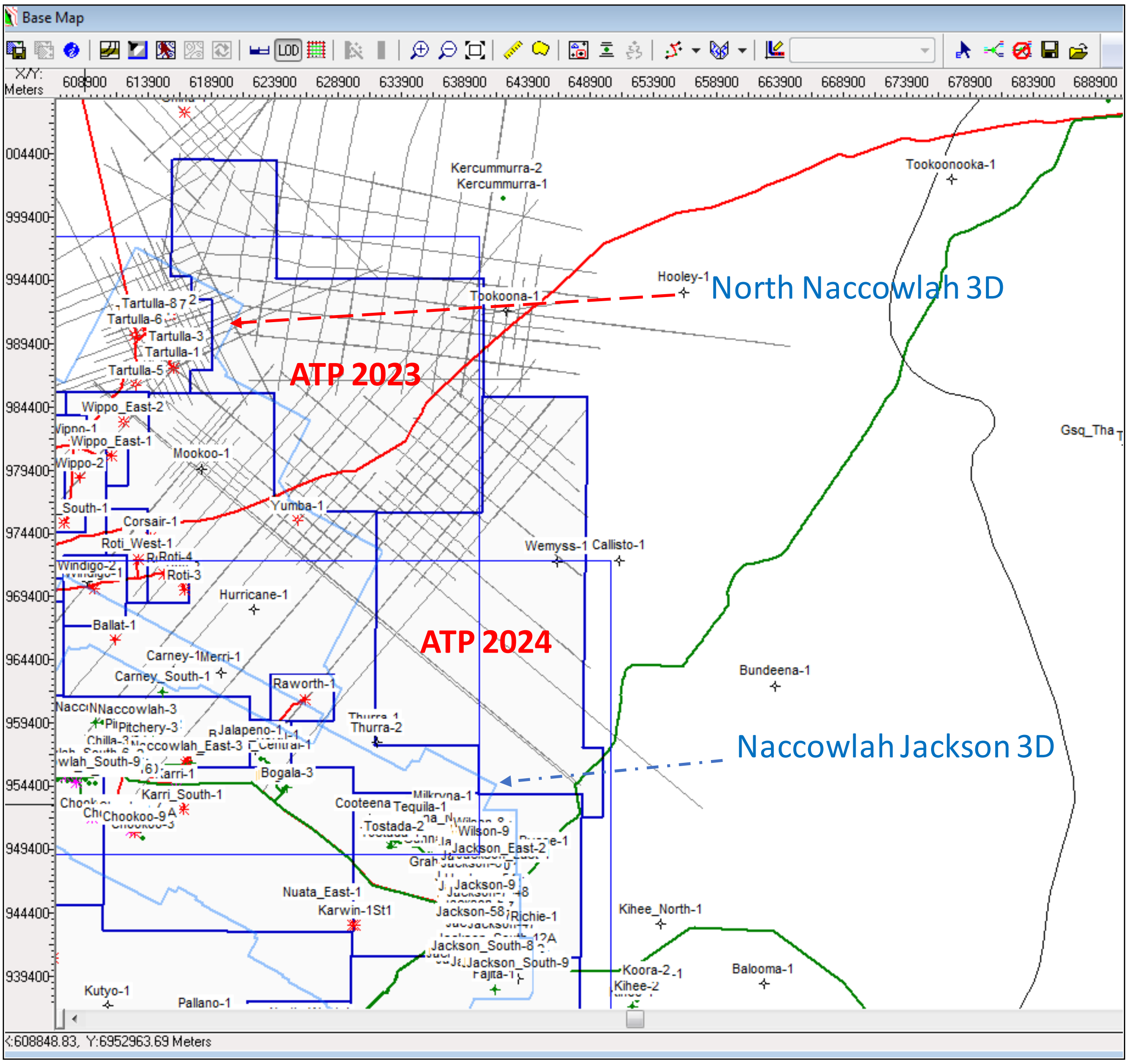

Figure 4-2: ATP 2023 and ATP 2024 well and seismic data coverage

Source: SRK

4.5 Permit status and commitments

The Approved Initial Work Program and Expenditure for ATP 2023 totals A$9.35 million across four years, and A$9.3 million for ATP 2024. Currently, Bridgeport has 100% equity in both permits (Table 4-2). The Queensland DNRME accepted Bridgeport as the preferred tenderer for ATP 2023 and ATP 2024 in December 2016. Native title and cultural clearance as part of the pre-grant release (Year 0) of ATP 2023 and ATP 2024 is still ongoing but progressing well. The DNRME has yet to grant title across both permits.

Table 4-2: ATP 2023 and ATP 2024 work program and commitments

ATP 2023 (1 January 2017 – 31 May 2021) - 100%			
Year	**Work program**	**Estimated cost ($)**	**Net cost ($)**
Year 0 (ending 31/12/2017)	Native title and cultural clearance	100,000	100,000
Year 1 (ending 31/12/2018)	Seismic reprocessing and Geological & Geophysical studies (G&G)	550,000	550,000
Year 2 (ending 31/12/2019)	Acquire 300 km^2 of 3D seismic	4,500,000	4,500,000
Year 3 (ending 31/12/2020)	G&G	200,000	200,000
Year 4 (ending 31/12/2021)	Drill two wells	4,000,000	4,000,000
Total		**9,350,000**	**9,350,000**

ATP 2024 (1 January 2017 – 31 December 2021) - 100%			
Year	**Work Program**	**Estimated cost ($)**	**Net cost ($)**
Year 0 (ending 31/12/2017)	Native title and cultural clearance	100,000	100,000
Year 1 (ending 31/12/2018)	Seismic reprocessing and G&G	500,000	500,000
Year 2 (ending 31/12/2019)	Acquire 300 km^2 of 3D seismic	4,500,000	4,500,000
Year 3 (ending 31/12/2020)	G&G	200,000	200,000
Year 4 (ending 31/12/2021)	Drill two wells	4,000,000	4,000,000
Total		**9,300,000**	**9,300,000**

Source: Bridgeport

4.6 Prospectivity

Bridgeport has identified several prospects and leads which are outlined in Table 4-3, with a Prospect and Lead (P&L) map shown in Figure 4-3.

SRK has reviewed the methodology and input parameters for the ATP 2023 and ATP 2024 lead inventory and confirmed the Prospective Resource estimates.

Table 4-3: Prospective Resources within ATP 2023 and ATP 2024 P&L Inventory

Prospect Lead	STOIIP - Whole Trap - MMSTB				Oil (MMSTB)				GCOS	Risked
	Mean	P90	P50	P10	Mean	P90	P50	P10	(%)	
Lead A	10.4	0.7	7	24.9	3.1	0.2	2	7.6	10	0.31
Prospect B	25.3	3	19.6	55.9	7.6	0.8	5.6	17.1	10	0.76
Prospect C	15.3	0.9	9.9	37.4	4.6	0.3	2.8	11.3	20	0.92
Prospect D	16.7	1.2	11.2	40	5	0.3	3.2	12.1	15	0.75
Lead E	6.7	0.6	4.5	15.5	2	0.2	1.3	4.7	14	0.28
Lead F	4.5	0.5	3.2	10.3	1.4	0.1	0.9	3.1	11	0.15
Lead G	5.1	0.5	3.7	11.7	1.5	0.1	1	3.6	11	0.17
Lead H	5.1	0.5	3.7	11.7	1.5	0.1	1	3.6	11	0.17
Lead I	3.1	0.3	2.1	7.2	0.9	0.1	0.6	2.2	11	0.1
Lead J	5.5	0.5	3.9	12.9	1.6	0.1	1.1	3.9	11	0.18
Lead K	11.7	0.8	7.9	28.1	3.5	0.2	2.3	8.5	14	0.49
Lead L	5.3	0.4	3.6	12.3	1.6	0.1	1	3.8	14	0.22
Lead M	2.2	0.2	1.5	5.2	0.7	0	0.4	1.6	14	0.1
Lead N	2.5	0.2	1.7	5.9	0.7	0.1	0.5	1.8	11	0.08
Lead O	5.1	0.5	3.7	11.7	1.5	0.1	1	3.6	14	0.21
Total	**124.5**	**10.8**	**87.2**	**290.7**	**37.2**	**2.8**	**24.7**	**88.5**		**4.90**

Source: Bridgeport

SRK has reviewed the current 2D seismic geophysical data and associated interpretations used to identify the prospect and leads within ATP 2023 and ATP 2024. Bridgeport provided risk assessments for Hutton Formation Prospects and Leads based on proximity to the interpreted hydrocarbon kitchen, proximity to analogous discoveries or hydrocarbon indications, depth, and robustness of structural interpretation due to seismic density and quality. Due to the variation of parameters, a 10%–20% GCOS is considered to cover the level of risk associated with these Prospects and Leads.

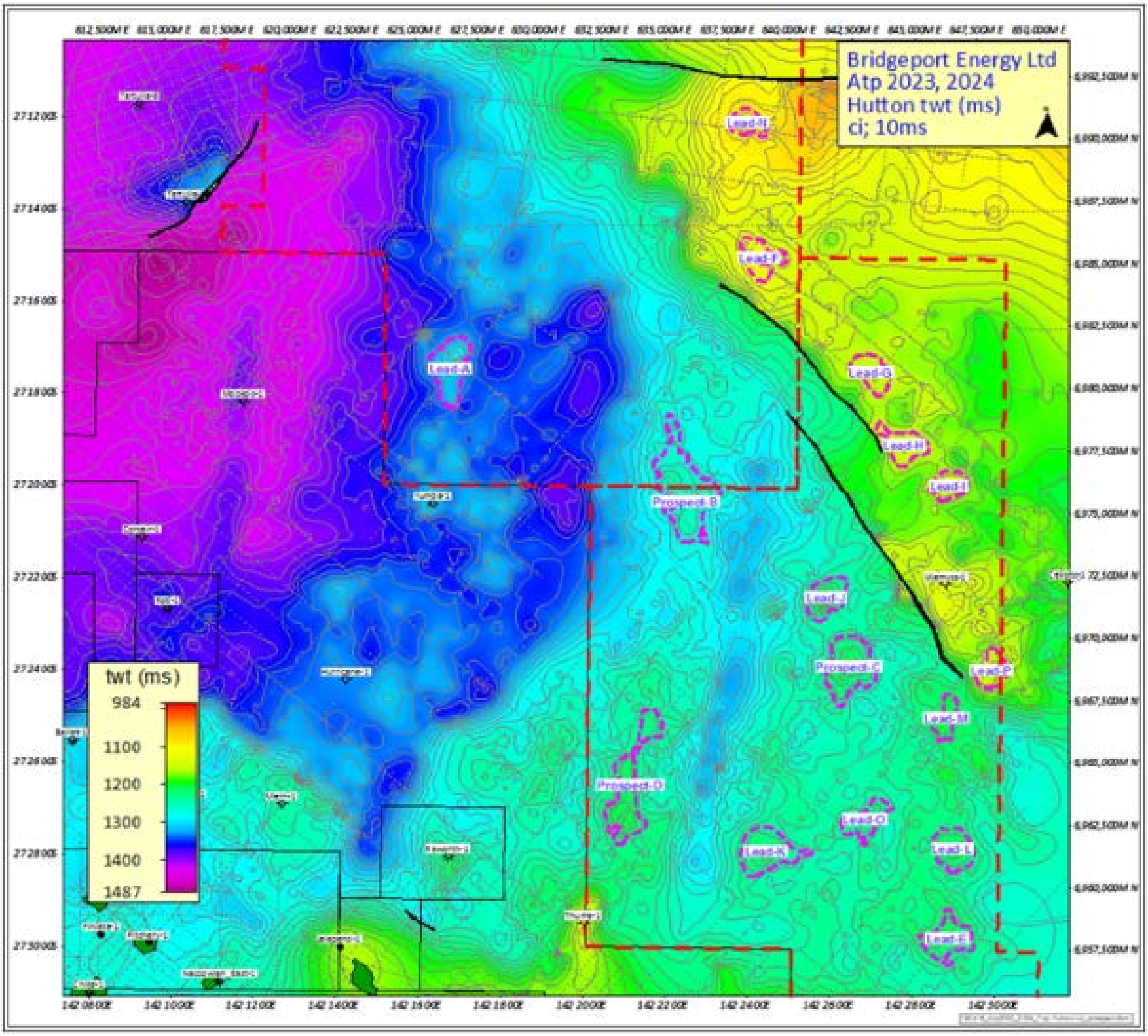

Figure 4-3: ATP 2023 and ATP 2024 Prospect and Lead map (Hutton Formation)
Source: Bridgeport

4.7 Review opinion

SRK considers these estimates for ATP 2023 and ATP 2024 to be high risk due to limited exploration in the permit areas to date and the requirement for further geological and geophysical work to be undertaken in these permits to convert the leads to drillable prospects. The acquisition of 600 km^2 of 3D seismic surveying as part of the Year 2 work program commitments will increase the GCOS.

It is SRK's opinion that the Prospective Resources within ATP 2023 and ATP 2024 as shown in Table 4-4 are reasonable and have been prepared in accordance with the definitions and guidelines contained in the PRMS and generally accepted petroleum engineering and evaluation principles set out in the SPE Reserves Auditing Standards.

SRK's examination included a probabilistic assessment of the classification and categorisation of the Prospective Resources. SRK's methods incorporated a range of uncertainty to allow the assignment of Low (P90), Best (P50) and High (P10) Prospective Resource categories in accordance with the PRMS.

Table 4-4: Assessment of Prospective Resources in ATP 2023 and ATP 2024 (Gross & Net to New Era)

Permit	Field	Gross Reserves and Resources (100% Equity)						
		Reserves (Mbbl) (PD+PDNP)			Prospective Resources (Mbbl)			
		1P	2P	3P	Low (P90)	Preferred (P50)	High (P10)	
ATP 2023/ATP 2024	Exploration				2800	24700	88500	As at 31 March 2019
Permit	**Field**	**Net Attributable Reserves and Resources (New Era)**						**Report by**
		Reserves (Mbbl) (PD+PDNP)			**Prospective Resources (Mbbl)**			
		1P	2P	3P	P90	P50	P10	
ATP 2023/ATP 2024	Exploration				1400	12350	44250	Post Farm-in 50% Equity

Source: SRK analysis

Notes:

1. Volumes reported are 100% gross equity and net entitlement to New Era for ATP 2023 and ATP 2024.
2. SRK agrees with the GCOS estimates by Bridgeport.
3. Estimates are in accordance with the Petroleum Resources Management System (SPE, 2007) and Guidelines for Application of the PRMS (SPE, 2011).
4. Probabilistic methods were used.
5. Original gas in-place (OGIP) excludes shrinkage and fuel.

5 Proposed Work Programs and Expenditure

For the purpose of determining the respective budgets for individual permits, SRK considered the permit commitment and estimated expenditures for the permit work programs (Table 5-1). SRK is not in a position to verify if all parties will require additional funding to undertake these work commitments and/ or if the work commitments will be completed prior to the title expiry.

Within 30 days of completion of all of the earning obligations in all four permits, New Era may either/or:

- Notify all parties of its election to accept an assignment of each of its Farm-in interests (or some of them) including future obligations and liabilities.
- Notify all parties that it does not wish to proceed with an assignment of its Farm-in interest (or some of them) and the Farm-in agreement will terminate with immediate effect (in respect of the relevant Permit) and the parties will each release the other from any further obligations and liabilities.

Table 5-1: Bridgeport/ New Era farm-in work commitments

Stage	Description	Gross cost (A$ million)	New Era to Fund	New Era Spend Cap (A$ million)	New Era to Earn
1a	PL 256 (Bargie/ Glenvale JV) – Drill offset well to Bargie-1	1.75	60%	1.00	**30%**
1b	ATP 948 – Drill one well	1.80	60%	1.06	
2a	ATP 2023/ ATP 2024 – Year 1 of Work Program Commitments	1.05	50%	0.53	**25%**
2b	ATP 2023/ ATP2024 – Year 2 of Work Program Commitments (600 km ^{2} seismic program)	9.00	50%	4.50	
2c	ATP 2023/ ATP 2024 – Year 3 of Work Program Commitments (four-well Commitment)	8.00	60%	4.80	**50%**
2d	ATP 2023/ ATP 2024 – Year 4 of Work Program Commitments	0.40	50%	0.20	
Total work program		**22.00**		**12.09**	

Source: SRK analysis

5.1 PL 256 and ATP 948

New Era will earn a 30% participating interest in PL 256 and ATP 948 but will be required to pay 60% of the cost of drilling a well in each permit to a minimum depth of 1,650 m to the base of the Basal Jurassic (Poolowanna) stratigraphic formation, up to a maximum of:

(A) A$1,000,000 at PL 256 (Bargie-Glenvale JV)

(B) A$1,060,000 at ATP 948.

5.2 ATP 2023 and ATP 2024

The forward works program for ATP 2023 and ATP 2024 is to acquire 3D seismic geophysical data to advance the understanding and mitigate risk over currently high-graded leads identified in the permit. SRK considers the work program to be reasonable and appropriate for the exploration of the permit.

In total, acquisition of 600 km^2 of 3D seismic surveying in Year 2 work program commitments will increase the GCOS by the acquisition of modern 3D seismic data.

In terms of funding, New Era's earn-in obligations and right to participating interest in ATP 2023 and ATP 2024 will occur in two stages:

a) A$525,000 in respect of the Year 1 work program across both permits to earn a 25% working interest.

b) 50% of the Year 2 work program (up to a maximum of A$2,250,000 per permit).

New Era intends to fund the initial A$525,000 in respect of the Year 1 work program for geophysical and geological studies. New Era will not be under any obligation to fund the Year 2 earning obligations and will make an assessment on whether it wishes to do so while the Year 1 work program is in progress. New Era may elect to proceed with the Year 2 earning obligations in respect of either of both of the permits. If New Era does not proceed with the Year 2 earn-in obligations, it will not earn any participating interest in the permits.

New Era can earn 25% in one block or up to 50% in each block by spending an additional $3.3 to $9.5mm depending upon the number of blocks and equity. New Era will be able to elect to receive the 25% participating interest at the end of Year 1 by pre-paying the Year 2 earn-in obligation to Bridgeport, in which case Bridgeport will immediately transfer a 25% working interest in the permits to New Era (subject to Ministerial approval of the transfer and the parties agreeing the terms of a formal Joint Operating Agreement (based on the AIPN/AMPLA Model Joint Operating Agreement and agreed key terms which will be set out in the ATP 2023/ATP 2024 Farm-in Agreement).

SRK considers New Era approach for both blocks reasonable and appropriate. The only obligation for New Era is to fund an initial A$525,000 to undertake the geological and geophysical review in the first year. This can be easily managed using New Era's available capital once the A$4.0 million is raised. Any subsequent work commitment will require additional funding.

5.3 Proposed work program

The proposed use of funds from the Public Offer in support of the proposed work programs within PL 256, ATP 948, ATP 2023 and ATP 2024 is shown in Table 5-2.

Table 5-2: Proposed use funds from the capital raising

Funds Available / Allocation	Minimum subscription - A$4,000,000	Percentage of funds (%)	Maximum subscription - A$5,000,000	Percentage of funds (%)
Funds Available				
Existing cash reserves of Indus	A$800,000		A$800,000	
Funds raised from the Offer	A$4,000,000		A$5,000,000	
Total	**A$4,800,000**	**100%**	**A$5,800,000**	**100%**
Allocation of Funds				
PL 256 Bargie-5 Appraisal Drilling farm-in	A$1,000,000	20.8%	A$1,000,000	17.2%
ATP 948 Exploration well farm-in	A$1,060,000	22.1%	A$1,060,000	18.3%
ATP 2023 & ATP 2024 studies	A$525,000	10.9%	A$525,000	9.1%
Expenses of the Offer	A$500,000	10.4%	A$460,000	9.8%
Corporate Overheads	A$500,000	10.4%	A$500,000	8.6%
Working Capital	A$1,215,000	25.3%	A$2,250,000	37.0%
Total	**A$4,800,000**	**100%**	**A$5,800,000**	**100%**

Source: New Era Oil and Gas

In SRK's opinion, the use of funds is consistent with the exploration and appraisal opportunities present and meet the current work program title requirements. SRK cautions that the Year 2 work programs are dependent on the results achieved in Year 1 and may be different to that initially proposed.

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Appendix A: Category Definitions of 1P, 2P and 3P

(PRMS, 2018) For further details on the definitions and guidelines, please see the original document.

Figure A-1 (from the World Petroleum Council) presents 1P, 2P and 3P category definitions and provides guidelines designed to promote consistency in resource assessments. The following summarises the definitions for each Reserves category in terms of both the deterministic incremental approach and scenario approach and also provides the probability criteria if probabilistic methods are applied.

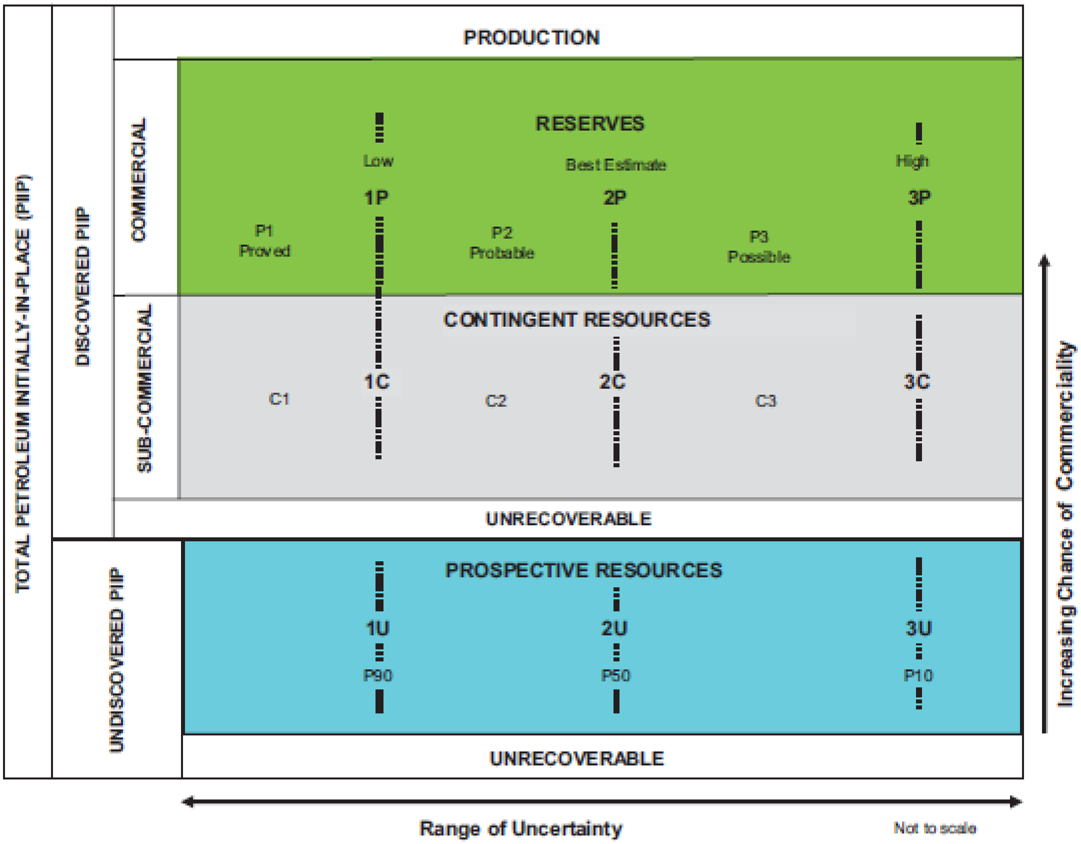

Figure A-1: Resources classification framework

- **Proved Reserves** are those quantities of petroleum, which, 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 that the quantities actually recovered will equal or exceed the estimate.
- **Probable Reserves** are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.
- **Possible Reserves** are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) Reserves, which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.

The “Range of Uncertainty” reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the “Chance of Commerciality”, that is, the chance that the project that will be developed and reach commercial producing status.

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

TOTAL PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to “total resources”).

DISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

PRODUCTION is the cumulative quantity of petroleum that has been recovered at a given date. While all recoverable resources are estimated and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage.

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

RESERVES are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria’s: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) 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 characterized by development and production status.

CONTINGENT RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, 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 categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

PROSPECTIVE RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

UNRECOVERABLE is that portion of Discovered or Undiscovered Petroleum Initially-in- Place quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur, the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Estimated Ultimate Recovery (EUR) is not a resources category, but a term that may be applied to any accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable under defined technical and commercial conditions plus those quantities already produced (total of recoverable resources).

In specialized areas, such as basin potential studies, alternative terminology has been used, the total resources may be referred to as Total Resource Base or Hydrocarbon Endowment. Total recoverable or EUR may be termed Basin Potential. The sum of Reserves, Contingent Resources and Prospective Resources may be referred to as "remaining recoverable resources." When such terms are used, it is important that each classification component of the summation also be provided. Moreover, these quantities should not be aggregated without due consideration of the varying degrees of technical and commercial risk involved with their classification.

Project-Based Resources Evaluations

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

This concept of a project-based classification system is further clarified by examining the primary data sources contributing to an evaluation of net recoverable resources (Figure A-2) that may be described as follows:

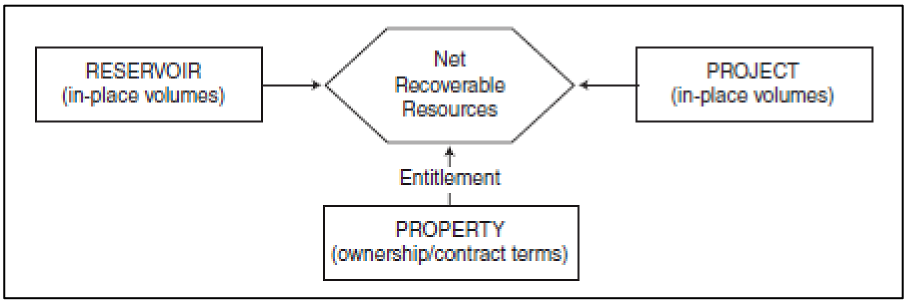

Figure A-2: Resources Evaluation data sources

Resources Classification

The basic classification requires establishment of criteria for a petroleum discovery and thereafter the distinction between commercial and sub-commercial projects in known accumulations (and hence between Reserves and Contingent Resources).

Determination of Discovery Status

A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons.

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 economic recovery. Estimated recoverable quantities within such a discovered (known) accumulation(s) shall initially be classified as Contingent Resources pending definition of projects with sufficient chance of commercial development to reclassify all, or a portion, as Reserves.

Where in-place hydrocarbons are identified, but are not considered currently recoverable, such quantities may be classified as Discovered Unrecoverable, if considered appropriate for resource management purposes, a portion of these quantities may become recoverable resources in the future as commercial circumstances change or technological developments occur.

Determination of Commerciality

Discovered recoverable volumes (Contingent Resources) may be considered commercially producible, and thus Reserves, if the entity claiming commerciality has demonstrated firm intention to proceed with development and such intention is based upon all of the following criteria:

- Evidence to support a reasonable timetable for development.
- A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria.
- A reasonable expectation that there will be a market for all or at least the expected sales quantities of production required justifying development.
- Evidence that the necessary production and transportation facilities are available or can be made available.
- Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated.

To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and 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 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are 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 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.

Project Status and Commercial Risk

Evaluators have the option to establish a more detailed resources classification reporting system that can also provide the basis for portfolio management by subdividing the chance of commerciality axis according to project maturity. Such sub-classes may be characterized by standard project maturity level descriptions (qualitative) and/or by their associated chance of reaching producing status (quantitative). As a project moves to a higher level of maturity, there will be an increasing chance that the accumulation will be commercially developed. For Contingent and Prospective Resources, this can further be expressed as a quantitative chance estimate that incorporates two key underlying risk components:

- The chance that the potential accumulation will result in the discovery of petroleum. This is referred to as the “chance of discovery”.
- Once discovered, the chance that the accumulation will be commercially developed is referred to as the “chance of development.”

Thus, for an undiscovered accumulation, the “chance of commerciality” is the product of these two risk components. For a discovered accumulation where the “chance of discovery” is 100%, the “chance of commerciality” becomes equivalent to the “chance of development.”

Project Maturity Sub-Classes

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

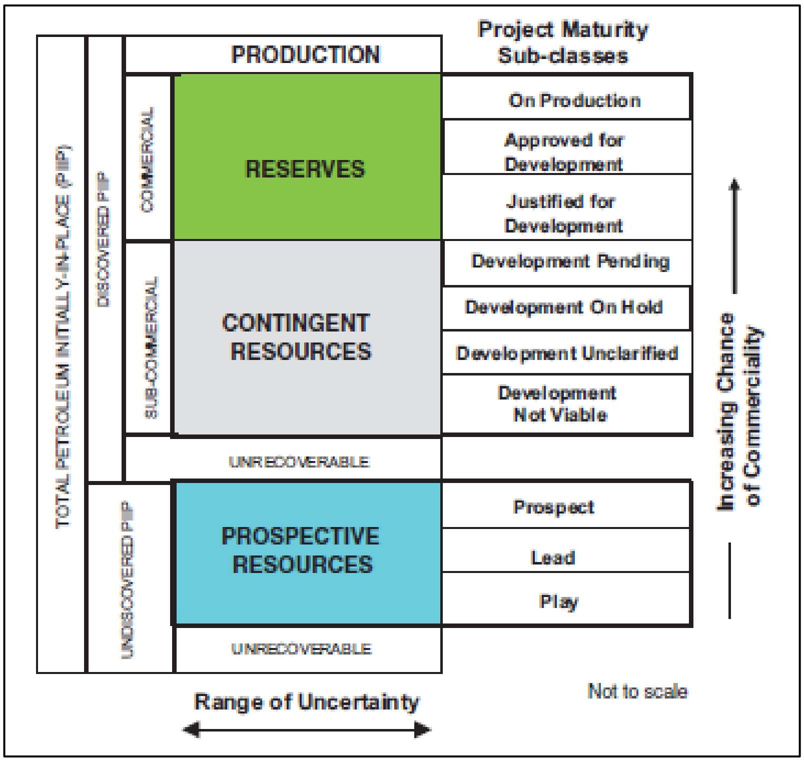

Figure A-3: Project maturity sub-classes

Project Maturity terminology and definitions have been modified from the example provided in the 2001 Supplemental Guidelines, Chapter 2. Detailed definitions and guidelines for each Project maturity sub-class are provided in Figure A-3. This approach supports managing portfolios of opportunities at various stages of exploration and development and may be supplemented by associated quantitative estimates of chance of commerciality. The boundaries between different levels of project maturity may be referred to as “decision gates.”

Decisions within the Reserves class are based on those actions that progress a project through final approvals to implementation and initiation of production and product sales. For Contingent Resources, supporting analysis should focus on gathering data and performing analyses to clarify and then mitigate those key conditions, or contingencies that prevent commercial development.

For Prospective Resources, these potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under appropriate development projects. The decision at each phase is to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity where a decision can be made to proceed with exploration drilling.

Evaluators may adopt alternative sub-classes and project maturity modifiers, but the concept of increasing chance of commerciality should be a key enabler in applying the overall classification system and supporting portfolio management.

Reserves Status

Once projects satisfy commercial risk criteria, the associated quantities are classified as Reserves. These quantities may be allocated to the following subdivisions based on the funding and operational status of wells and associated facilities within the reservoir development plan:

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

Where Reserves remain undeveloped beyond a reasonable timeframe, or have remained undeveloped due to repeated postponements, evaluations should be critically reviewed to document reasons for the delay in initiating development and justify retaining these quantities within the Reserves class. While there are specific circumstances where a longer delay (see Determination of Commerciality, section 2.1.2) is justified, a reasonable time frame is generally considered to be less than 5 years.

Development and production status are of significant importance for project management. While Reserves Status has traditionally only been applied to Proved Reserves, the same concept of Developed and Undeveloped Status based on the funding and operational status of wells and producing facilities within the development project are applicable throughout the full range of Reserves uncertainty categories (Proved, Probable and Possible).

Quantities may be subdivided by Reserves Status independent of sub-classification by Project Maturity. If applied in combination, Developed and/or Undeveloped Reserves quantities may be identified separately within each Reserves sub-class (On Production, Approved for Development, and Justified for Development).

Economic Status

Projects may be further characterized by their Economic Status. All projects classified as Reserves must be economic under defined conditions.

Based on assumptions regarding future conditions and their impact on ultimate economic viability, projects currently classified as Contingent Resources may be broadly divided into two groups:

- Marginal Contingent Resources are those quantities associated with technically feasible projects that are either currently economic or projected to be economic under reasonably forecasted improvements in commercial conditions but are not committed for development because of one or more contingencies.
- Sub-Marginal Contingent Resources are those quantities associated with discoveries for which analysis indicates that technically feasible development projects would not be economic and/or other contingencies would not be satisfied under current or reasonably forecasted improvements in commercial conditions. These projects nonetheless should be retained in the inventory of discovered resources pending unforeseen major changes in commercial conditions.

Where evaluations are incomplete such that it is premature to clearly define ultimate chance of commerciality, it is acceptable to note that project economic status is “undetermined.” Additional economic status modifiers may be applied to further characterize recoverable quantities; for example, non-sales (lease fuel, flare, and losses) may be separately identified and documented in addition to sales quantities for both production and recoverable resource estimates. Those discovered in-place volumes for which a feasible development project cannot be defined using current or reasonably forecast improvements in technology are classified as Unrecoverable.

Economic Status may be identified independently of, or applied in combination with, Project Maturity sub-classification to more completely describe the project and its associated resources.

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