ABN 45 066 383 971

2 March 2015 **PAGES (including this page):180**

ASX Market Announcements
ASX Limited
Exchange Centre
Level 4, 20 Bridge Street
Sydney NSW 2000

Supplementary Target's Statement in relation to the on-market cash takeover offer by NZOG Offshore Limited

As required by section 647(3)(b)(ii) of the Corporations Act 2001 (Cth) (as amended), enclosed is a copy of the Supplementary Target's Statement dated 2 March 2015 (the Supplementary Target's Statement) prepared by Cue Energy Resources Limited (ABN 45 066 383 971) (Cue Energy).

This Supplementary Target's Statement supplements Cue Energy's Target's Statement dated 24 February 2015 in relation to the on-market cash takeover offer by NZOG Offshore Limited (the Bidder) to acquire all of the shares in Cue Energy.

The Supplementary Target's Statement has been lodged today with the Australian Securities and Investments Commission and sent to the Bidder.

Yours faithfully

Andrew M Knox
Chief Financial Officer

CUE ENERGY OVERVIEW

Cue is an Australian based oil & gas company with activities in Australia, New Zealand, Indonesia and PNG.

THE COMPANY HAS:

- Long life production
- A strong balance sheet
- An active exploration program

CUE ENERGY DIRECTORS

- Geoffrey King (Chairman)
- Stuart Brown
- Rowena Sylvester
- Andrew Young

CUE ENERGY MANAGEMENT

- David Biggs (CEO)
- Andrew Knox (CFO)
- Jeffrey Schrull (Exp Man)

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LISTINGS
ASX: CUE

THIS IS AN IMPORTANT DOCUMENT AND REQUIRES YOUR IMMEDIATE ATTENTION. YOU SHOULD READ ALL OF THE DOCUMENT. IF YOU ARE IN DOUBT AS TO WHAT YOU SHOULD DO, YOU SHOULD CONSULT YOUR INVESTMENT, FINANCIAL, TAXATION OR OTHER PROFESSIONAL ADVISER.

Supplementary Target's Statement

REJECT

Your Directors unanimously recommend that you REJECT the Offer made by NZOG Offshore to acquire all of your shares in Cue Energy for just $0.10 per share

IF YOU HAVE ANY QUESTIONS, PLEASE CONTACT THE CUE ENERGY SHAREHOLDER INFORMATION LINE ON 1300 373 864 (WITHIN AUSTRALIA) OR +61 3 9415 4109 (OUTSIDE AUSTRALIA) BETWEEN 9.00AM AND 5.00PM (MELBOURNE TIME) MONDAY TO FRIDAY.

Financial Adviser

UBS

Legal Adviser

Allens > < Linklaters

Allens

Supplementary Target's Statement

This document is a supplementary target's statement under section 644(1) of the Corporations Act (***Supplementary Target's Statement***), dated 2 March 2015. This is the first supplementary target's statement issued by Cue Energy Resources Limited (ABN 45 066 383 971) (***Cue Energy***) and supplements Cue Energy's Target Statement dated 24 February 2015. This Supplementary Target's Statement is to be read together with the Target's Statement.

Important Notices

This Supplementary Target's Statement has been lodged with ASIC and provided to the ASX. Neither ASIC, ASX nor any of their respective officers take any responsibility for the content of this document.

It is important that you read the Target's Statement and this Supplementary Target's Statement in their entirety before making any investment decision and any decision relating to the Offer. Your Directors encourage you to obtain independent advice from your investment, financial, taxation or other professional adviser before making a decision whether or not to accept the Offer.

The Independent Expert's Report has been prepared by the Independent Expert for the purposes of the Target's Statement and the Independent Expert is responsible for that report. Neither Cue Energy nor any of its officers, employees or advisers assumes any responsibility for the accuracy or completeness of the Independent Expert's Report, except, in the case of Cue Energy, in relation to any information which it has provided to the Independent Expert.

The Technical Specialist's Report has been prepared by the Technical Specialist for the purposes of the Target's Statement and the Technical Specialist is responsible for that report. Neither Cue Energy nor any of its officers, employees or advisers assumes any responsibility for the accuracy or completeness of the Technical Specialist's Report, except, in the case of Cue Energy, in relation to information which it has provided to the Technical Specialist.

This Supplementary Target's Statement prevails to the extent of any inconsistency with the Target's Statement. Capitalised terms used in this Supplementary Target's Statement have the same meaning as defined in section 8 of the Target's Statement unless otherwise defined.

1 Half-Year Report

On 26 February 2015 Cue Energy released its half-year report for the 6 months ended 31 December 2014. A copy of the announcement is attached as Annexure 1.

The half-year report sets out the financial results for the Company for the 6 months to 31 December 2014. The Directors note, in particular, the Company's strong reported net profit after tax (***NPAT***) for the half-year of A$13.8m which should be compared with the value of Cue Energy's equity implied by the A$0.10 per share Offer of approximately A$69.8m.

The table below sets out the reported NPAT results of some junior ASX-listed exploration and production companies for the 6 months ended 31 December 2014.

Company	Reported NPAT
Drillsearch Energy[1]	A$14.3m
Cue Energy[2]	**A$13.8m**
Horizon Oil[3]	US$7.3m
New Zealand Oil & Gas[4]	NZ$(10.5)m
Cooper Energy[5]	A$(58.0)m
AWE[6]	A$(61.7)m
Senex Energy[7]	A$(65.9)m

The Directors are of the view that Cue Energy's results are reflective of the current strategy of maximising value from existing assets and maintaining a diversified and balanced portfolio of exploration, development and production opportunities.

2 Independent Expert's Report

As previously announced, Grant Samuel was appointed by the Directors to prepare an Independent Expert's Report in relation to the Offer. Grant Samuel has now provided Cue Energy with its report which concludes that the Offer **is neither fair nor reasonable** and that the Offer of $0.10 per share falls below the bottom end of the valuation range for Cue Energy Shares.

The Independent Expert has determined the value of a Cue Energy Share on a controlling interest basis to be in the range of $0.117 to $0.152 per share.

A copy of the Independent Expert's Report is attached as Annexure 2.

3 Technical Specialist's Report

As part of the preparation of the Independent Expert's Report, RISC Advisory was engaged to prepare a Technical Specialist's Report. The Technical Specialist's Report provides detailed information about Cue Energy's assets, including valuations of its exploration assets and is included as Appendix 3 of the Independent Expert's Report.

4 Correction

Section 2.2(c) of the Target's Statement sets out the premium which the Offer Price represents to the closing price of Cue Energy Shares on 11 February 2015, being the last day prior to the

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1 See page 1 of Drillsearch Energy's half-year report for the 6 months ended 31 December 2014 for disclosure of reported NPAT.

2 See page 18 of Cue Energy's report for the 6 months ended 31 December 2014 for disclosure of reported NPAT.

3 See page 1 of Horizon Oil's report for the 6 months ended 31 December 2014 for disclosure of reported NPAT.

4 See page 1 of New Zealand Oil & Gas' report for the 6 months ended 31 December 2014 for disclosure of reported NPAT.

5 See page 9 of Cooper Energy's half-year report for the 6 months ended 31 December 2014 for disclosure of reported NPAT.

6 See page 5 of AWE's half-year report for the 6 months ended 31 December 2014 for disclosure of reported NPAT.

7 See page 2 of Senex Energy's half-year report for the 6 months ended 31 December 2014 for disclosure of reported NPAT.

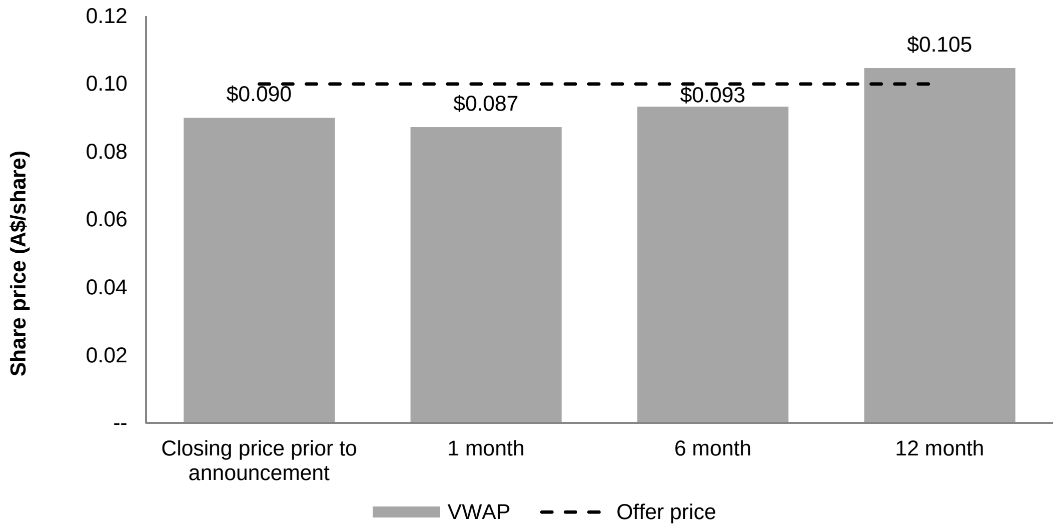
announcement of the Offer, and the premia which the Offer Price represents to the VWAP of Cue Energy Shares for the 1 month, 6 month and 12 month periods ending on 11 February 2015.

In that section, it was stated that the VWAP of Cue Energy Shares for the 6 months ending on 11 February 2015 was $0.096, when the VWAP for that period was in fact $0.093. This means that the Offer Price of $0.10 per share implies a premium of 7% to that 6 month VWAP, rather than 4% as stated in the original Target's Statement.

The premia implied by the Offer Price of $0.10 per share are therefore:

- 11% to the closing price of Cue Energy shares of $0.090 on 11 February 2015;
- 15% to the 1 month VWAP to 11 February 2015 of $0.087;
- 7% to the 6 month VWAP to 11 February 2015 of $0.093; and
- a discount of 5% to the 12 month VWAP to 11 February 2015 of $0.105.

The graph on page 13 of the Target's Statement should therefore also read as follows:



Source: Cue Energy Share price data supplied by IRESS.

The Directors remain of the view that these premiums are substantially below the premiums typically paid in an Australian context, and below what the Directors consider to be appropriate.

5 Consents

The following persons have given and have not, before the date of this Supplementary Target's Statement, withdrawn their consent to the inclusion of the following information in this Supplementary Target's Statement in the form and context in which it is included, and to all references in this Supplementary Target's Statement to that information in the form and context in which it appears:

- RISC Advisory – to the inclusion of statements said to be based on statements made by the Technical Specialists or made in the Technical Specialist's Report;
- Grant Samuel – to the inclusion of statements said to be based on statements made by the Independent Expert or made in the Independent Expert's Report.

As permitted by ASIC Class Order 13/521, this Supplementary Target's Statement contains statements that are made, or based on statements made, in documents lodged with ASIC or ASX (in compliance with the Listing Rules). Pursuant to this Class Order, the consent of persons to whom such statements are attributed is not required for the inclusion of those statements in this Supplementary Target's Statement.

Any Cue Energy Shareholder who would like to receive a copy of any of the documents (or parts of the documents) that contain the statements which have been included pursuant to ASIC Class Order 13/521 may during the Offer Period obtain a copy free of charge by contacting the Cue Energy Shareholder Information line on 1300 373 864 (within Australia) or +61 3 9415 4109 (outside Australia) between 9.00am and 5.00pm (Melbourne time) Monday to Friday.

As permitted by ASIC Class Order 07/429, this Supplementary Target's Statement also contains trading data obtained from IRESS, without its consent to the inclusion of such trading data.

6 Approval of Supplementary Target's Statement

This Supplementary Target's Statement has been approved by a resolution passed by the Directors of Cue Energy. Each Director of Cue Energy voted in favour of the resolution authorising this Target's Statement.

Dated 2 March 2015.

Signed for and on behalf of Cue Energy:

Geoffrey King

Chairman

Annexure 1 – ASX Announcement: Half-Year Report

HALF-YEAR REPORT

FOR THE FINANCIAL PERIOD ENDED 31 DECEMBER 2014

FINANCIAL SUMMARY

	31 Dec 2014	31 Dec 2013	Percentage Change Over Comparative
	$'000	$'000	%
Production Income	18,641	14,776	26.16
Gross Profit from Production	12,004	5,177	131.87
Profit/(Loss) after Income Tax	13,753	(1,136)	N/A

KEY POINTS

Existing Permit Activity

- Sale of PNG asset portfolio for US$7m completed.
- 100% working interest and operatorship of the Mahakam Hilir PSC, Indonesia acquired, subject to completion.

Production

- Maari growth project proceeding with the MR8A well on production and the MR6A well currently drilling. Growth project drilling expected to be completed in mid 2015.
- Sampang PSC well workover and compression installation underway which should extend the field life of Oyong oil production and maintain gas production from Oyong and Wortel.
- Cue is currently reviewing opportunities to acquire producing assets.

Exploration

- Planning underway for the Naga Selatan -2 well to be drilled in the Mahakam Hilir PSC in the second half of 2015.
- 12.5% interest acquired in the Mahato PSC in Indonesia (subject to government approval) with 2 wells planned for 2015.
- 100% of WA-409-P acquired. Cue is compiling a prospect portfolio across both WA-409-P and its other 100% owned permit, WA-359-P, with a view to farming out in 2015.
- PEP 51313 Whio (NZ) offshore exploration well plugged and abandoned with shows.
- PEP 51149 Te Kiri (NZ) onshore exploration well scheduled to be drilled in Q4 2015.
- Cue continues to review new exploration opportunities in Australia/Asia.

RESULTS FOR ANNOUNCEMENT TO THE MARKET
FOR THE HALF-YEAR ENDED 31 DECEMBER 2014

Current Reporting Period: Half-year ended 31 December 2014
Previous Corresponding Period: Half-year ended 31 December 2013

	Percentage Change Over Comparative	Amount (6 month period ended 31 December 2014) $'000
Production income	26.16%	18,641
Profit after tax attributable to members	N/A	13,753
Net profit attributable to members	N/A	13,753

Dividends

No dividends have been paid or proposed.

Brief Explanation of Revenue and Net Profit

(i) Revenue from Ordinary Activities

Increase in revenues can be attributed mainly to increased production uptime at Maari.

(ii) Net Result

The $13.75m profit after tax was primarily as a consequence of the following movements:-

	31 Dec 2014	31 Dec 2013	Movement
	$'000	$'000	%
Production Income	18,641	14,776	26.16
Production Costs	(6,637)	(9,599)	(30.86)
Amortisation Expense	(5,024)	(4,301)	16.81
Foreign Exchange Gain	5,022	2,391	110.04
Sale of PNG Assets	5,830	-	N/A
Income Tax (Expense)/Credit	(358)	(1,076)	(66.73)

	31 Dec 2014	31 Dec 2013
Net Tangible Assets Per Ordinary Security	15.1 cents	15 cents

CORPORATE DIRECTORY

Directors
Geoffrey J. King, BA, LL.B (Chairman)
Stuart A. Brown, BSc (Hons)
Rowena A. Sylvester, BBS
Andrew A. Young, BE, MBA (Hons)

Chief Executive Officer
D.A.J. Biggs, LL.B

Chief Financial Officer/Company Secretary
A.M. Knox, B.Com

Co-Company Secretary
P.M. Moffatt, B.Com

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ABN 45 066 383 971

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Melbourne, Victoria 3000 Australia

UNITED STATES OF AMERICA
OTC Markets
304 Hudson Street, 3rd Floor
New York, NY 10013 USA

Auditor
BDO East Coast Partnership
Level 14, 140 William Street
Melbourne Victoria 3000 Australia

Bankers
ANZ Banking Group Limited
91 William Street
Melbourne Victoria 3000 Australia

ASB Bank Limited
PO Box 35, Shortland Street
Auckland 1140 New Zealand

National Australia Bank Limited
Level 4, 330 Collins Street
Melbourne Victoria 3000 Australia

Share Registry
AUSTRALIA
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GPO Box 2975
Melbourne, Victoria 3000 Australia
Telephone: 1300 850 505 (within Australia)
or +61 3 9415 4000 (outside Australia)
Email: web.queries@computershare.com.au
Website: www.computershare.com.au

CONTENTS

DIRECTORS REPORT

The Directors present their report together with the consolidated Financial Report of Cue Energy Resources Limited (“Cue”) for the half-year ended 31 December 2014.

DIRECTORS

The Directors of the Group in office during and since the half-year are as follows:

G.J. King (Chairman)
S.A. Brown
R.A. Sylvester
A.A. Young

RESULT

The consolidated profit after tax for the half-year ended 31 December 2014 amounted to $13.75m (2013: $1.14m loss).

During the half-year the Group earned production income of $18.64m (2013: $14.78m) and incurred production costs of $6.64m (2013: $9.60m). Foreign exchange movements resulted in a gain of $5.02m (2013: $2.4 gain). The Group divested its interests in PNG resulting in a profit of $5.83m (2013: nil).

DIVIDENDS

No dividends were paid or declared during the half-year.

SIGNIFICANT CHANGES IN THE STATE OF AFFAIRS

There were no significant changes in the state of affairs of the consolidated entity during the financial half-year.

SUMMARY

EXPLORATION

- In New Zealand the PEP 51313 Whio offshore exploration well was plugged and abandoned with shows (Cue 100% carried) and the drilling of the Te Kiri well in PEP 51149 is now scheduled for late 2015.

- A farm-in for 12.5% of the Mahato PSC in the prolific Central Sumatra Basin in Indonesia was concluded (subject to government approval) with 2 wells planned for 2015 along with 2D seismic acquisition. The block is near several major oil fields, (including Minas and Duri) and has a deep portfolio of exploration and appraisal prospects.

- Seismic processing and planning for the drilling of the Naga Selatan -2 well in the Mahakam Hilir PSC (100% Cue – subject to completion) has progressed during the half-year with drilling planned for Q3 2015.

- Post 31 December 2015, Cue moved to a 100% operated position in the WA-409-P block offshore Western Australia following the withdrawal of the other partners in the permit. The forward plan in 2015 is to farm-out WA-409-P jointly with WA-359-P due to the shared high impact prospectivity of the 2 Blocks.

DEVELOPMENT

- The Maari growth project continued during the half-year with drilling activities on the MR6A, MR8A and MR7A wells. The MR8A well commenced production in November. The MR5 well was also worked over and brought on production. The MR6A and MR7A wells will be drilled and completed in Q1 2015.

  It is anticipated the growth project will be completed in mid 2015.

PRODUCTION

- Oil production at the Maari field was significantly higher than the prior period. Production for the half-year ended 31 December 2013 was affected by repairs to the swivel and FPSO mooring system resulting in approximately five months of interrupted production.

FINANCIAL

HALF-YEAR REVENUE

Revenue receipts from hydrocarbon production for the half-year were $18.64m on sales of 99,914 barrels of oil at an average price of $88 per barrel and 1,347,428 thousand cubic feet (Mcf) of gas at an average price of $6 per Mcf.

- Cue has no hedging in place.
- Cue has no debt.
- Cash and cash equivalents on hand at the end of the half-year was $37.10m.

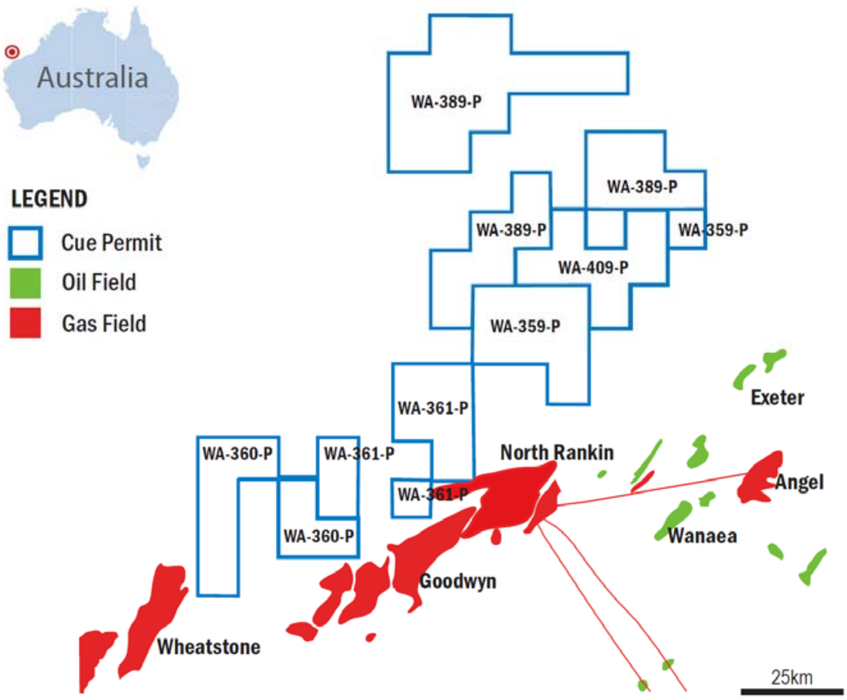
CORPORATE

On 18 August, Cue announced the appointment of Mr Jeff Schrull as General Manager, Exploration and Production. Jeff is a highly experienced oil and gas industry executive with 25 year's experience in the upstream exploration and production business.

Cue welcomed New Zealand Oil & Gas Limited (NZOG) as a new substantial shareholder with 19.99% of the ordinary shares on issue.

Subsequent to the half-year end, NZOG announced to the market an on-market cash takeover offer for shares in Cue from NZOG Offshore Limited at $0.10 per share. The offer will remain open until Friday 27 March 2015 (unless extended or withdrawn). The Board considers the offer from NZOG substantially undervalues the Company, and advised shareholders to reject the offer and not to sell their Cue Energy shares on-market at the offer price of $0.10 per share. The offer is open from 27 February to 27 March 2015. The Board will keep shareholders duly informed of material developments.

ACTIVITY REVIEW
AUSTRALIA - CARNARVON BASIN



WA-359-P
Cue Interest: 100%
Operator: Cue Exploration Pty Ltd

Cue is evaluating the regional prospectivity in all of its WA permits and is maturing a significant new exploration play.

Cue will market WA-359-P as part of a farmdown of its portfolio of WA assets to interested parties in 2015. Additional technical work has been undertaken to lower the geologic risk on Sherlock, estimated to have a STOOIP of 300 million bbls.

WA-360-P
Cue Interest: 37.5%
Operator: MEO Australia Limited

The WA-360-P Joint Venture is completing the reprocessing of approximately 650 km² of existing 3D seismic data over the Maxwell prospect to improve imaging of the structure. On completion of the reprocessing, it is expected that activity to farm-down our interest in the permit will recommence before the end of the primary term of the permit in 2016. There is no well commitment in the primary term.

WA-361-P
Cue Interest: 15%
Operator: MEO Australia Limited

NOPTA has approved an application for a work programme variation to allow the Joint Venture to complete geotechnical studies ahead of making any commitment to drill a well. The reduced work programme term concludes on 30 January 2016.

WA-389-P
Cue Interest: 40%
Operator: BHP Billiton Petroleum (Australia) Pty Ltd

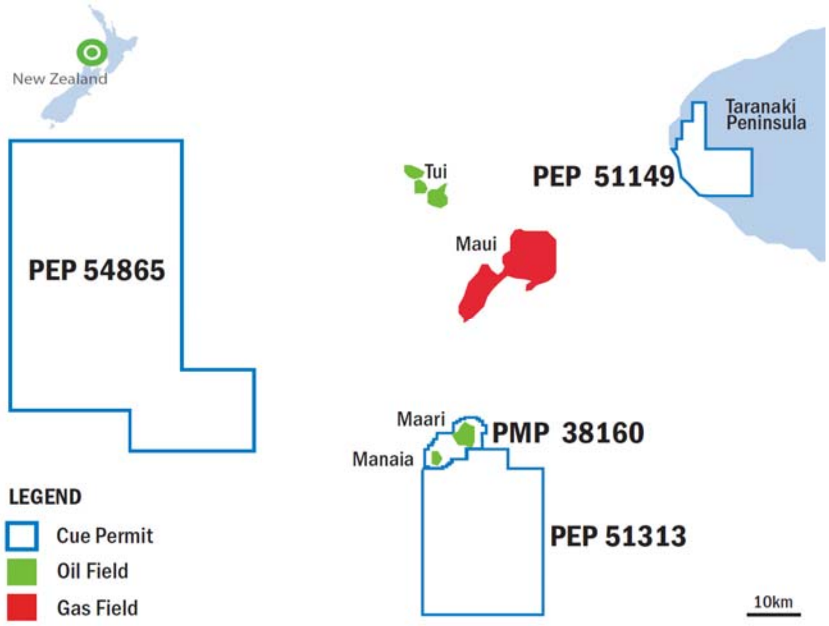
Reprocessing of existing 2D and 3D seismic data has been approved by the Joint Venture and is expected to be complete in mid 2015.

WA-409-P
Cue Interest: 100%
Operator: Cue Exploration Pty Ltd

Cue has acquired operatorship and 100% interest in the block due to the withdrawal of the other Joint Venture parties. An extension has been granted until the end of April 2015 to complete the evaluation of the block using the seismic data reprocessed by Apache in 2014. There is currently no well commitment on the block. Cue will market WA-409-P as part of a farmdown of its portfolio of WA assets to interested parties in 2015.

NEW ZEALAND - TARANAKI BASIN

EXPLORATION



PEP 51149
Cue Interest: 20%
Operator: Todd Exploration Limited

The drilling of the Te Kiri North -1 well is expected in Q4 2015. Te Kiri North -1 will be drilled up dip of hydrocarbon shows in the Te Kiri -1 well. Cue's estimate in a success case of the mean prospective recoverable resource of the well is 2 million boe net to Cue. Existing infrastructure nearby will facilitate early commercialisation in a success case.

PEP 54865
Cue Interest: 20%
Operator: Todd Exploration Limited

PEP 54865 carries a minimum work programme of 285 km² of 3D seismic to be acquired, processed and interpreted prior to June 2015. After this, the Joint Venture may elect to drill a well before December 2016 to test Early Tertiary and Late Cretaceous reservoir objectives, or surrender the permit. Planning for the 3D seismic survey has commenced, however, data acquisition may be deferred until 2016 pending government approval and boat availability.

The Joint Venture is seeking a farminee to fund the seismic programme.

PEP 51313
Cue Interest: 14% interest
Operator: OMV New Zealand Limited

The Joint Venture is focused on the remaining potential associated with the Matariki trend which is up-dip of Maari. Studies will be undertaken in 2015 to determine the best approach to seismic processing to mature a potentially drillable prospect.

PRODUCTION

PMP 38160
Cue Interest: 5%
Operator: OMV New Zealand Limited

Maari and Manaia Fields

Cue's share of oil sales in the half-year from the Maari and Manaia fields was 77,673 barrels which generated $7.486m in revenue.

The average oil production rate was approximately 7,036 gross barrels per day (Cue net: 352 bopd).

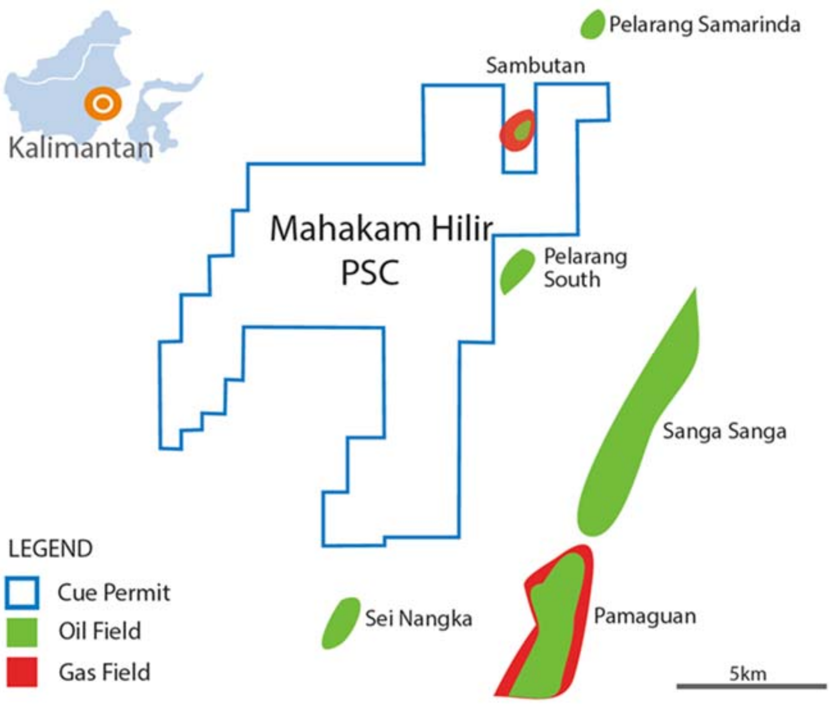
Maari growth project activities continued through the half-year with the Ensco 107 jack-up rig contracted for the drilling and work-over campaign. The drilling has taken longer than anticipated due to drilling conditions that have proved to be more challenging than anticipated. Drilling through geological faults in the field is a main contributor to delays in the programme. The operator has adjusted the drilling procedures to mitigate these delays in future wells. The MR8A well has been completed and is producing at 1,200 bopd, however an additional zone in the well will be completed via a workover after the drilling programme is finished. This should enhance the production rate from the well. The MR5 well has been worked over and is now on production. As of 24 February 2015 the MR6A well was drilling ahead in the Mangahewa reservoir and is planned to be completed once it reaches final depth. The MR7A well was suspended in January 2015 due to difficulties with the well and will be re-entered and drilling recommenced after the MR6A well is completed. The remainder of the programme includes a producer drilled in a position that will allow it to be converted to a future injector and potentially an additional producer which is currently under consideration by the Joint Venture. Production is expected to fluctuate whilst drilling the development wells as operations require individual wells to be temporarily shut in.

Ensco 107 at Maari WHP

INDONESIA

EXPLORATION

Mahakam Hilir PSC Kutei Basin
Cue Interest: 100% (subject to completion)
Operator: SPC (Mahakam Hilir) Pte Ltd



Cue has entered into a sale and purchase agreement with SPC to move to 100% interest in the Mahakam Hilir PSC in the prolific Kutei Basin onshore Kalimantan, Indonesia. Cue will purchase SPC Mahakam Hilir Pte Ltd, which holds the remaining 60% interest in the Mahakam Hilir PSC. Cue will assume operatorship with a 100% interest in the PSC and drill the remaining commitment well in the PSC. Government approval for the transfer has been received.

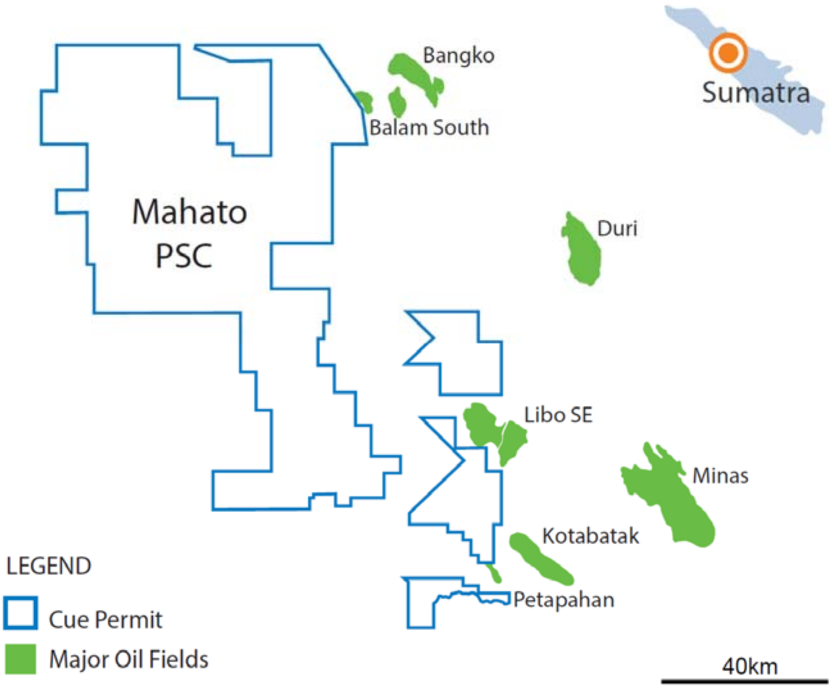
As part of an internal review of options around the permit Cue has identified a robust drill-ready oil prospect, Naga Selatan -2 (Southern Dragon) which has encouraged Cue to remain in the permit and move to a 100% interest.

This oil prospect lies along trend from the large Sei Nangka and South Pelarang oil fields. The multiple targets are shallow, located at approximately 1000'-3000' TVD. Additional exploration objectives have also been identified on the existing seismic data.

Drilling programme preparations have commenced and the well is planned for 2015.

This marks Cue's first entry as a drilling operator. This acquisition complements the continuing expansion of our Indonesian acreage portfolio.

Mahato PSC
Central Sumatra Basin
Cue Interest: 12.5% (subject to approval)
Operator: Texcal Mahato Ltd



On 21 November 2014, Cue announced the execution of a farm-in agreement with Bukit Energy to acquire a 12.5% interest in the Mahato PSC, onshore Central Sumatra, Indonesia. This transaction is currently pending Indonesian government approval, which is expected this quarter.

The Mahato PSC covers a highly prospective area, close to several large producing oil fields. Multiple appraisal and exploration opportunities have been mapped and 2 wells are currently planned for mid 2015. A 2D seismic programme to high grade further exploration prospects is also planned for 2015.

PRODUCTION

Sampang PSC- Madura Strait
Cue Interest: 15%
Operator: Santos (Sampang) Pty Ltd

Oyong Field

Oil sales of 15,161 barrels resulted in $1.682m of revenue during the half-year.

Cue's share of condensate sales in the half-year was 185 barrels which generated $0.011m in revenue. Cue's share of gas sales was 480,490 Mcf, which generated $1.710m in revenue during the half-year.

The Oyong oil production rate at year end was approximately 1,300 bopd gross (Cue net 169 bopd) and the gas rate 26 MMscfd gross (Cue net 3.61 MMscfd).

Based on continued improved production rates, the Joint Venture approved extension of the contracts for the Oyong production barge and FSO until September 2015. A programme of well interventions and recompletions is currently underway. The planned workovers are expected to improve Oyong oil production and extend field life for an additional 1-2 years until 2017.

Wortel Field

Cue's share of gas sales was 866,938 Mcf, which generated $6.990m in revenue during the half-year.

Cue's share of condensate sales in the half-year was 291 barrels which generated $0.017m in revenue.

Wortel -3 and Wortel -4 flowed gas at year end at a combined average rate of 43 MMscfd (gross) (Cue 5.97 MMscfd net of government take under the PSC.)

The Joint Venture has approved the installation of compression at the Grati gas plant which will ensure that the Wortel project will continue to meet its gas sales contract volumes. Installation of the compressors is progressing and is scheduled to be complete by end Q1 2015.

PAPUA NEW GUINEA

EXPLORATION

PRL 14 (10.947% interest)
Operator: Oil Search (PNG) Limited
No significant activity to report.

PRL 9 (14.894% interest)
Operator: Oil Search (PNG) Limited
No significant activity to report.

PRODUCTION

PDL 3 SE Gobe Field, PNG
Cue Interest: 5.568892%
SE Gobe Unit, PNG
Cue Interest: 3.285646%
Operator: Oil Search (PNG) Limited

Cue's share of oil sales was 6,604 barrels of oil from the SE Gobe field during the half-year, which generated $0.745m in revenue.

Cue has sold its PNG interests to the National Petroleum Company of Papua New Guinea. The sale proceeds of US$7m for Cue's PNG asset portfolio have been received. This will be the last report referring to Cue's PNG interests.

ROUNDING OF AMOUNTS

The Company is of a kind referred to in class order 98/100 issued by the Australian Securities and Investments Commission relating to "rounding of amounts" in the Directors Report. Amounts in the Directors Report and the Half-Year Financial Report have been rounded off in accordance with that class order to the nearest thousand dollars, or in certain cases, to the nearest dollar where appropriate.

AUDITOR INDENDENCE DECLARATION

A copy of the auditor independence declaration is set out on page 17.

Signed in accordance with a resolution of Directors, pursuant to section 306(3)(a) of the Corporations Act 2001.

On behalf of the Board of Directors

Rowena A Sylvester
Director
Dated at Melbourne this 26th day of February 2015.

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www.bdo.com.au

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GPO Box 5099 Melbourne VIC 3001
AUSTRALIA

DECLARATION OF INDEPENDENCE BY ALEX SWANSSON TO THE DIRECTORS OF CUE ENERGY RESOURCES LIMITED

As lead auditor for the review of Cue Energy Resources Limited for the half-year ended 31 December 2014, I declare that, to the best of my knowledge and belief, there have been:

1. No contraventions of the auditor independence requirements of the *Corporations Act 2001* in relation to the review; and
2. No contraventions of any applicable code of professional conduct in relation to the review.

This declaration is in respect of Cue Energy Resources Limited and the entities it controlled during the period.

Alex Swansson
Partner

BDO East Coast Partnership

Melbourne, 26 February 2015

CONSOLIDATED STATEMENT OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME FOR THE HALF-YEAR ENDED 31 DECEMBER 2014

	NOTE	31 DEC 2014 $000's	31 DEC 2013 $000's
Production income		18,641	14,776
Production costs		(6,637)	(9,599)
Gross Profit from Production		12,004	5,177
Other revenue	2	5,888	84
Amortisation expense		(5,024)	(4,301)
Net foreign currency exchange gain		5,022	2,391
Other expenses	3	(3,779)	(3,411)
Profit/(loss) before income tax		14,111	(60)
Tax expense		(358)	(1,076)
Profit/(loss) after income tax for the half-year		13,753	(1,136)
Other comprehensive income			
Other comprehensive income for the half-year, net of tax		-	-
Profit/(loss) for the half-year is attributable to: owners of Cue Energy Resources Limited		13,753	(1,136)
Total comprehensive income for the half-year is attributable to : owners of Cue Energy Resources Limited		13,753	(1,136)
Basic earnings/(loss) per share (cents per share)		1.97	(0.16)
Diluted earnings/(loss) per share (cents per share)		1.97	(0.16)

The accompanying notes form part of and are to be read in conjunction with these Financial Statements.

CONSOLIDATED STATEMENT OF FINANCIAL POSITION
AS AT 31 DECEMBER 2014

	NOTE	31 DEC 2014 $000's	30 JUN 2014 $000's
Current Assets			
Cash and cash equivalents		37,103	40,558
Trade and other receivables		4,282	3,542
Inventories		865	843
Total Current Assets		42,250	44,943
Non Current Assets			
Property, plant and equipment		82	118
Deferred tax assets		-	71
Exploration and evaluation expenditure		55,477	54,069
Production properties		83,103	79,458
Total Non Current Assets		138,662	133,716
Total Assets		180,912	178,659
Current Liabilities			
Trade and other payables		10,279	21,184
Tax liabilities		4,802	2,398
Provisions		685	563
Total Current Liabilities		15,766	24,145
Non Current Liabilities			
Deferred tax liabilities		17,437	19,484
Provisions		4,553	5,627
Total Non Current Liabilities		21,990	25,111
Total Liabilities		37,756	49,256
Net Assets		143,156	129,403
Equity			
Issue capital	5	152,416	152,416
Reserves		-	-
Accumulated losses		(9,260)	(23,013)
Total Equity		143,156	129,403

The accompanying notes form part of and are to be read in conjunction with these Financial Statements.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
FOR THE HALF-YEAR ENDED 31 DECEMBER 2014

	Issued Capital $000's	Reserves $000's	Accumulated Losses $000's	Total $000's
At 1 July 2014	152,416	-	(23,013)	129,403
Profit for the period	-	-	13,753	13,753
Other comprehensive income	-	-	-	-
Total comprehensive income for the period	**-**	**-**	**13,753**	**13,753**
As at 31 December 2014	152,416	-	(9,260)	143,156
At 1 July 2013	152,416	22	(20,869)	131,569
Loss for the period	-	-	(1,136)	(1,136)
Other comprehensive income	-	-	-	-
Total comprehensive loss for the period	**-**	**-**	**(1,136)**	**(1,136)**
As at 31 December 2013	152,416	22	(22,005)	130,433

The accompanying notes form part of and are to be read in conjunction with these Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOWS
FOR THE HALF-YEAR ENDED 31 DECEMBER 2014

	31 DEC 2014	31 DEC 2013
	$000's	**$000's**
Cash Flows From Operating Activities		
Production receipts	16,252	15,301
Interest received	63	95
Payments to employees and other suppliers	(9,998)	(12,454)
Royalties paid	(491)	(466)
Net Cash provided by Operating Activities	5,826	2,476
Cash Flows From Investing Activities		
Payments for exploration expenditure	(13,157)	(5,442)
Payments for property, plant and equipment	(7)	(137)
Payments for production property	(9,675)	(7,946)
Proceeds from sale of Cue PNG Oil Company Pty Ltd	8,536	-
Net Cash used in Investing Activities	(14,303)	(13,525)
Net decrease in Cash and Cash Equivalents	(8,477)	(11,049)
Cash and cash equivalents at the beginning of the period	40,558	58,828
Effect of exchange rate change on foreign currency balances held at balances held at the beginning of the period	5,022	2,365
Cash and Cash Equivalents at the end of the Period	37,103	50,144

The accompanying notes form part of and are to be read in conjunction with these Financial Statements.

NOTE 1 STATEMENT OF SIGNIFICANT ACCOUNTING POLICIES

(a) Statement of compliance

The half-year financial report is a general purpose financial report prepared in accordance with the Corporations Act 2001 and AASB 134 'Interim Financial Reporting'. Compliance with AASB 134 ensures compliance with International Financial Reporting Standard IAS 34 'Interim Financial Reporting'. The half-year financial report does not include notes of the type normally included in an annual financial report and should be read in conjunction with the most recent annual financial report, together with any public announcements made by Cue Energy Resources Limited (the "Group").

The Group has adopted all of the new and revised Standards and Interpretations issued by the Australian Accounting Standards Board (the AASB) that are relevant to their operations and effective for the current reporting period.

There are no new and revised Standards and amendments thereof and Interpretations effective for the current reporting period that are material to the Group.

The adoption of all the new and revised Standards and Interpretations has not resulted in any changes to the Group's accounting policies and has no effect on the amounts reported for the current or prior periods. The new and revised Standards and Interpretations have not had a material impact and not resulted in changes to the Group's presentation of, or disclosure in, its half-year financial statements.

The Group has not elected to early adopt any other new standards or amendments that are issued but not yet effective.

(b) Basis of preparation

The half-year financial statements have been prepared on the basis of historical cost, except for the revaluation of certain non-current assets and financial instruments. Cost is based on the fair values of the consideration given in exchange for assets. All amounts are presented in Australian dollars, unless otherwise noted.

The accounting policies and methods of computation adopted in the preparation of the half-year financial report are consistent with those adopted and disclosed in the company's annual financial report for the year ended 30 June 2014.

The company is a company of the kind referred to in ASIC Class Order 98/100, dated 10 July 1998, and in accordance with that Class Order amounts in the half-year financial report are rounded off to the nearest thousand dollars, unless otherwise indicated.

The fair values of assets and liabilities not carried at fair value as at 31 December 2014, are not materially different from the carrying values presented in these accounts.

NOTE 1 STATEMENT OF SIGNIFICANT ACCOUNTING POLICIES (cont')

(c) Principles of consolidation

The consolidated financial statements are those of the consolidated entity, comprising the financial statements of the parent entity and of all entities which Cue Energy Resources Limited controlled from time to time during the period and at the reporting date.

The financial statements of subsidiaries are prepared for the same reporting period as the parent entity, using consistent accounting policies. Adjustments are made to bring into line any dissimilar accounting policies, which may exist. All inter-company balances and transactions, including any unrealised profits or losses have been eliminated on consolidation.

NOTE 2 OTHER REVENUE

	31 DEC 2014 $'000	31 DEC 2013 $'000
Sale of Cue PNG Oil Company Pty Ltd	5,830	-
Interest from Cash and Cash Equivalents	58	84
Total Other Revenue	5,888	84

NOTE 3 OTHER EXPENSES

	31 DEC 2014 $'000	31 DEC 2013 $'000
Depreciation	44	33
Employee Benefits Expense	1,969	1,865
Operating Lease	130	177
Administration Expenses	560	632
Business Development	1,076	704
Total Other Expenses	3,779	3,411

NOTE 4 SEGMENT INFORMATION

The Group operates predominantly in one business, namely the exploration development and production of hydrocarbons. Revenue is derived from the sale of gas and liquid hydrocarbons.

Segment results, assets and liabilities include items directly attributable to a segment as well as those that can be allocated on a reasonable basis. Unallocated items mainly comprise interest-earning assets and revenue, interest-bearing borrowings and expenses, and corporate assets and liabilities.

Segment capital expenditure is the total cost incurred during the period to acquire segment assets that are expected to be used for more than one period.

Geographic Segments

The Group operates primarily in Australia but also has international operations in Indonesia, Papua New Guinea and New Zealand. Therefore the Group is organised into four principles geographic segments: Australia, New Zealand, Indonesia and Papua New Guinea. These segments are based on the internal reports that are reviewed and used by the board of directors (who are identified as the chief operating decision makers (CODM)) in assessing performance and in determining the allocation of resources.

The CODM assess the performance of the operating segments based upon a measure of earnings before interest expense, tax, depreciation and amortisation. The information reported to the CODM is on at best a monthly basis.

NOTE 4 SEGMENT INFORMATION (cont')

	Australia $'000	NZ $'000	Indonesia $'000	PNG $'000	Total $'000
Half-year 2014					
Total segment revenue	5,888	7,486	10,410	745	24,529
Inter-segment revenue	-	-	-	-	-
Revenue from external customers	5,888	7,486	10,410	745	24,529
Earnings before interest expense, tax, depreciation and amortisation	7,175	4,407	7,327	270	19,179
Half-year 2013					
Total segment revenue	84	1,453	12,421	902	14,860
Inter-segment revenue	-	-	-	-	-
Revenue from external customers	84	1,453	12,421	902	14,860
Earnings/(loss) before interest expense, tax, depreciation and amortisation	(904)	(154)	5,583	(251)	4,274
Total segment assets					
31 December 2014	44,311	78,611	57,795	195	180,912
30 June 2014	47,200	73,342	54,282	3,835	178,659
Total segment liabilities					
31 December 2014	1,745	12,844	23,167	-	37,756
30 June 2014	1,927	15,582	30,477	1,270	49,256

Reconciliation of earnings before interest expense, tax, depreciation and amortisation (EBITDA) to Profit before Income Tax:

	31 DEC 2014 $'000	31 DEC 2013 $'000
EBITDA	19,179	4,274
Amortisation and depreciation expenses	(5,068)	(4,334)
Profit/(loss) before Income Tax	14,111	(60)

NOTE 5 EQUITY - ISSUED CAPITAL

	31 DEC 2014 Number	30 JUN 2014 Number	31 DEC 2014 $'000	30 JUN 2014 $'000
Ordinary shares fully paid (no par value)	698,119,720	698,119,720	152,416	152,416

NOTE 6 EVENTS SUBSEQUENT TO REPORTING DATE

Subsequent to the half-year end, the Board announced to the market that an on-market cash takeover offer for shares from NZOG Offshore Limited (a wholly owned subsidiary of New Zealand Oil & Gas Limited - "NZOG") at $0.10 per share had been received. The offer will remain open until Friday 27 March 2015 (unless extended or withdrawn). As stated the Board considers the offer from NZOG substantially undervalues the Company, and advised shareholders to reject the offer and not to sell their Cue Energy shares on-market at the offer price of $0.10 per share. The Board will keep shareholders duly informed of material developments.

Apart from the above, the Directors are not aware of any matters or circumstances which have arisen since the end of the financial half-year, not otherwise dealt with in this report, which may significantly effect the operations of the entity, the results of those operations or state of affairs of the Group.

NOTE 7 CONTINGENT ASSETS/LIABILITIES

As a result of an economic project arrangement in the Jeruk field within the Sampang PSC, Indonesia, Cue may in certain circumstances have an obligation to reimburse certain monies spent by the incoming party from future profit oil within the Sampang PSC. There is a dispute between Cue and the incoming party as to the quantum of monies that they may be entitled to claim by way of such reimbursement and when any such reimbursement would be payable. The Company is of the view that any amount which might eventually become payable would not be likely to exceed the amount of US$4.7m. An arbitration hearing found in favour of Cue's position, however claims made by the incoming party are yet to be settled and hence there is still significant judgement and estimation in relation to these legal claims.

Cue estimates its share of the cost of the Maari repairs programme is approximately US$4m of which a portion is expected to be recovered from insurance.

Apart from the above, there has been no change since 30 June 2014 in reportable contingent assets or liabilities.

DIRECTORS DECLARATION

In accordance with a resolution of the Directors of Cue Energy Resources Limited, I state that:
In the opinion of the Directors:

(a) the financial statements and notes of the consolidated entity are in accordance with the Corporations Act 2001, including:

  (i) giving a true and fair view of the financial position as at 31 December 2014 and the performance for the half-year ended on that date of the consolidated entity; and

  (ii) complying with Accounting Standard AASB 134 'Interim Financial Reporting' and the Corporations Regulations 2001 and other mandatory reporting requirements; and

(b) there are reasonable grounds to believe that the Company will be able to pay its debts as and when they become due and payable.

On behalf of the Board of Directors

Rowena A Sylvester
Director

Dated at Melbourne this 26th day of February 2015

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INDEPENDENT AUDITOR'S REVIEW REPORT

To the members of Cue Energy Resources Limited

Report on the Half-Year Financial Report

We have reviewed the accompanying half-year financial report of Cue Energy Resources Limited, which comprises the consolidated statement of financial position as at 31 December 2014, the consolidated statement of profit or loss and other comprehensive income, the consolidated statement of changes in equity and the consolidated statement of cash flows for the half-year ended on that date, notes comprising a statement of accounting policies and other explanatory information, and the directors' declaration of the consolidated entity comprising the company and the entities it controlled at the half-year's end or from time to time during the half-year.

Directors' Responsibility for the Half-Year Financial Report

The directors of the company are responsible for the preparation of the half-year financial report that gives a true and fair view in accordance with Australian Accounting Standards and the *Corporations Act 2001* and for such internal control as the directors determine is necessary to enable the preparation of the half-year financial report that is free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express a conclusion on the half-year financial report based on our review. We conducted our review in accordance with Auditing Standard on Review Engagements ASRE 2410 *Review of a Financial Report Performed by the Independent Auditor of the Entity*, in order to state whether, on the basis of the procedures described, we have become aware of any matter that makes us believe that the half-year financial report is not in accordance with the *Corporations Act 2001* including: giving a true and fair view of the consolidated entity's financial position as at 31 December 2014 and its performance for the half-year ended on that date; and complying with Accounting Standard AASB 134 *Interim Financial Reporting* and the *Corporations Regulations 2001*. As the auditor of Cue Energy Resources Limited, ASRE 2410 requires that we comply with the ethical requirements relevant to the audit of the annual financial report.

A review of a half-year financial report consists of making enquiries, primarily of persons responsible for financial and accounting matters, and applying analytical and other review procedures. A review is substantially less in scope than an audit conducted in accordance with Australian Auditing Standards and consequently does not enable us to obtain assurance that we would become aware of all significant matters that might be identified in an audit. Accordingly, we do not express an audit opinion.

Independence

In conducting our review, we have complied with the independence requirements of the *Corporations Act 2001*. We confirm that the independence declaration required by the *Corporations Act 2001*, which has been given to the directors of Cue Energy Resources Limited, would be in the same terms if given to the directors as at the time of this auditor's review report.

Conclusion

Based on our review, which is not an audit, we have not become aware of any matter that makes us believe that the half-year financial report of Cue Energy Resources Limited is not in accordance with the *Corporations Act 2001* including:

(a) giving a true and fair view of the consolidated entity's financial position as at 31 December 2014 and of its performance for the half-year ended on that date; and

(b) complying with Accounting Standard AASB 134 *Interim Financial Reporting* and *Corporations Regulations 2001*

BDO East Coast Partnership

BDO

Alex Swansson
Partner

Melbourne, 26 February 2015

Annexure 2 – Independent Expert's Report

LEVEL 6

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28 February 2015

The Directors
Cue Energy Resources Limited
Level 19
357 Collins Street
Melbourne VIC 3000

Dear Directors

On-market takeover offer by New Zealand Oil & Gas

1 Introduction

Cue Energy Resources Limited ("Cue Energy") is an Australian oil and gas production and exploration company. Cue Energy's major assets are its cash holding, its 5% interest in the producing Maari oilfield offshore New Zealand and its 15% interest under the Sampang Production Sharing Contract ("PSC") in producing oil and gas fields offshore Java, Indonesia. In addition, it has a portfolio of exploration interests in Indonesia, Australia and New Zealand. Listed on the Australian Securities Exchange ("ASX"), as of 12 February 2015 Cue Energy had a market capitalisation of approximately $63 million.

On 12 February 2015, New Zealand Oil & Gas Limited ("NZOG") announced that, through its wholly owned subsidiary NZOG Offshore Limited, it was making an on-market takeover offer ("Offer") of 10 cents cash per share for all the shares in Cue Energy that it does not already own. The Offer values Cue Energy at approximately $70 million. At the time of the announcement of the Offer NZOG already owned 19.99% of the shares in Cue Energy, acquired off-market for 10 cents per share during December 2014. Subsequent on-market acquisitions have lifted NZOG's shareholding (as at 26 February 2015) to 20.11%.

The Offer is unconditional and must remain open until at least 27 March 2015.

The directors of Cue Energy have engaged Grant Samuel & Associates Pty Limited ("Grant Samuel") to prepare an independent expert's report setting out whether, in Grant Samuel's opinion, the Offer is fair and reasonable to Cue Energy shareholders. A copy of the report will be included in a supplementary Target's Statement to be sent by Cue Energy to its shareholders. This letter contains a summary of Grant Samuel's opinion and main conclusions.

2 Summary of Opinion

Grant Samuel has valued Cue Energy in the range 11.7-15.2 cents per share. The Offer price of 10 cents per share is below the bottom end of this valuation range. Accordingly, in Grant Samuel's opinion, the Offer is not fair.

A substantial proportion of Cue Energy's value is contributed by its cash holding (approximately 5 cents per share based on Cue Energy's cash holding as at 31 December 2014). However, a significant proportion of this cash is expected to be spent on exploration. Exploration outcomes are intrinsically uncertain. Moreover, the value of Cue Energy's Maari interest is subject to uncertainty, given a lack of clarity about its operational prospects and its exposure to volatile oil prices. As a result, the value of Cue Energy could change, perhaps materially, in the short to medium term.

While in Grant Samuel's opinion the Offer is not fair, judgements regarding the reasonableness of the Offer are less straight forward. The Offer of 10 cents per share is around 15% below the bottom end of Grant Samuel's valuation range and represents only a modest premium relative to recent Cue Energy share prices (although premium analysis in the circumstances of the Offer is not conclusive). NZOG's 20.1% shareholding in Cue Energy, while not an absolute obstacle to a third party proposal, does significantly reduce shareholders' prospects of realising value through some

alternative change of control transaction. On the other hand, since the announcement of the Offer Cue Energy shares have generally traded above the Offer price of 10 cents. Having regard to these factors, in Grant Samuel's view the Offer is, on balance, not reasonable.

Grant Samuel has therefore concluded that the Offer is neither fair nor reasonable.

3 Key Conclusions

- **Grant Samuel has valued Cue Energy in the range 11.7-15.2 cents per share.**

  Grant Samuel has valued Cue Energy in the range A$82-106 million, which corresponds to a value of 11.7-15.2 cents per share. The valuation represents the estimated full underlying value of Cue Energy and includes a premium for control. The value exceeds the price at which, based on current market conditions, Grant Samuel would expect Cue Energy shares to trade on the ASX in the absence of a takeover offer.

  The valuation is summarised below:

Cue Energy - Valuation Summary ($ millions)					
	Report Section Reference	Value Range (US$m)		Value Range ($m)	
		Low	High	Low	High
Maari	5.4	19	24	24	30
Sampang	5.4	12	16	15	20
Exploration	5.4			10	20
Other assets and liabilities	5.5			(2)	(1)
Head office costs (net of savings)	5.6			(4)	(2)
Enterprise value				**43**	**67**
Net cash at 31 December 2014	5.7			39	39
Value of equity				**82**	**106**
Fully diluted shares on issue (millions)				698.1	698.1
Value per share (cents)				**11.7**	**15.2**

  The valuation is principally based on discounted cash flow ("DCF") analysis.

  Grant Samuel appointed RISC Operations Pty Ltd ("RISC") as technical specialist to review Cue Energy's interests in the Maari field and the Sampang PSC. RISC's role included a review of reserves, development plans, production profiles and capital and operating costs. RISC also prepared a valuation of Cue Energy's exploration interests. RISC's report is attached to Grant Samuel's report.

  Grant Samuel's financial analysis was based on valuation scenarios prepared in conjunction with RISC, reflecting RISC's judgements regarding the range of assumptions as to ultimate hydrocarbon recoveries, capital costs and operating costs that could reasonably be adopted for valuation purposes. The valuation assumes that oil prices increase from current prices around US$60/bbl (Brent) to long run prices of US75-85/bbl (Brent). Present values were estimated in US$ terms using nominal discount rates of 9.5-10.5%, and converted to Australian dollar equivalents at a spot exchange rate of A$1.00 = US$0.79.

  The valuation is based on a number of important assumptions, including assumptions regarding oil prices, exchange rates and future operating performance. Oil prices, exchange rates and expectations regarding future operating performance can change significantly over short periods of time. Such changes could have a significant impact on the value of Cue Energy.

- **Cue Energy's value could change, possibly materially, over the short to medium term.**

  A substantial component of Cue Energy's value is contributed by its cash holding, which was approximately US$35 million as at 31 December 2014. The cash holding represents around 5 cents per share. However, a significant proportion of the cash holding (or alternatively of the free cash flows from Cue Energy's interests in producing assets) is expected to be devoted to Cue Energy's exploration programme, which involves total budgeted expenditures of around US$22 million over the next three years. The ultimate value of Cue Energy's exploration interests is, by the very nature of exploration, highly uncertain, and could fall within a relatively wide range. For some of the major exploration targets the exploration outcomes are likely to be binary, such that the ultimate value of the interests is likely to be either much greater than the current estimates of value or close to zero.

  Similarly, the value of Cue Energy's interest in the producing Maari field could potentially fall within a wide range. The Maari field has been the subject of a number of initiatives designed to increase production and extend field life (the "Maari Growth Project'). However, these initiatives have generally yielded disappointing results, characterised by cost overruns, production delays and well performance below expectation. RISC has assessed that there is considerable uncertainty in relation to the production performance of existing and future planned wells. A major component of the Maari Growth Project is a planned water injection programme, which has the potential to significantly boost ultimate oil recoveries. There is at least some risk that the water injection programme will not deliver the estimated benefits. Grant Samuel's valuation reflects a judgemental risking of the range of potential outcomes as advised by RISC. The actual future outcome could be better or worse than the outcomes implicit in Grant Samuel's valuation judgements.

  Grant Samuel's valuation of Cue Energy in the range 11.7-15.2 cents per share reflects Grant Samuel's estimate of the current market value of Cue Energy's assets. Shareholders should understand that the value of Cue Energy's assets could change, possibly materially, in a relatively short timeframe:

  - there is a wide range of potential operational/technical outcomes for some of Cue Energy's assets (particularly Maari and Cue Energy's exploration interests);

  - the range of outcomes could result in significant shifts in value (either positive or negative); and

  - the value of Cue's asset base is sensitive to movements in the oil price. The oil price has been highly volatile in recent months.

  Accordingly, Cue Energy's future value could be significantly greater than - or significantly less than - Grant Samuel's estimate of Cue Energy's current value.

- **The Offer of 10 cents per share represents only a modest premium relative to Cue Energy's pre-Offer share price. However, given the circumstances of the Offer premium analysis is not conclusive.**

  The Offer of 10 cents per share represents the following premiums relative to Cue Energy's pre-Offer share price:

Cue Energy – Implied Premiums over Pre-announcement Share Prices		
Date/Period	**Share Price**	**Premium**
11 February 2015 - pre-announcement price	9.00	11%
1 week prior to 11 February 2015 - VWAP[1]	8.86	13%
1 month prior to 11 February 2015 - VWAP	8.73	15%
3 month prior to 11 February 2015 - VWAP	8.09	24%
12 month prior to 11 February 2015 - VWAP	10.51	(5)%

Source: Bloomberg and Grant Samuel analysis

The Offer represents a modest premium relative to the Cue Energy share price immediately before the announcement of the Offer. For longer periods it represents a negligible premium or even a discount to weighted average share prices. The calculated premiums are significantly lower than the premiums commonly paid in change of control transactions (generally in the range 20-35%).

Premium analysis in the circumstances of the Offer must be treated with considerable caution. NZOG's acquisition of a 19.99% interest in Cue Energy was announced on 22 December 2014. It appears highly likely that trading in Cue Energy shares following that announcement and prior to the announcement of the Offer reflected speculation as to some form of corporate transaction involving NZOG. Cue Energy's last traded price before the announcement of NZOG's acquisition of a 19.99% shareholding in Cue Energy was 8.5 cents, and Cue Energy shares generally traded in the range 7.5-8.5 cents for the three weeks before the announcement (i.e. for the first three weeks of December 2014). The Offer represents much larger premiums relative to this range of share prices (approximately 18-33%).

Cue Energy's shares traded at higher prices prior to December 2014, with a volume weighted average price of 9.4 cents for November 2014 and a trading range generally above 10 cents for the first ten months of 2014. However, it should be recognised that those higher share prices reflected higher oil prices (the oil price fell from US115/bbl (Brent) on 19 June 2014 to around US70/bbl at 30 November 2014, by comparison with prices as low as US$55/bbl during December 2014). Accordingly, premiums calculated relative to Cue Energy's share price in the months preceding December 2014 provide little useful evidence for assessing the Offer.

More broadly, the limited liquidity of Cue Energy shares (with approximately 56% of its shares on issue held by its top four shareholders) means that Cue Energy's share price is not necessarily a reliable benchmark for value. In this context, premium analysis may not be particularly meaningful.

Overall, while the Offer represents only a modest premium to Cue Energy's pre-Offer share price, premium analysis is not conclusive.

- **The Offer is, on balance, not reasonable.**

  An offer can be reasonable notwithstanding that it is not fair if there are compelling reasons for shareholders to accept the offer. This is generally the case when shareholders have no realistic prospect of realising value greater than the offer price, commonly because the bidder already has a controlling interest in the target company. In the case of the Offer, the following factors are relevant to an assessment of reasonableness:

1 VWAP refers to volume weighted average prices.

- the Offer price of 10 cents per share is approximately 15% lower than the bottom end of Grant Samuel's valuation range of 11.7-15.2 cents per share;
- while Cue Energy shares could trade at prices below the Offer price in the absence of the Offer, the Cue Energy share price should be supported at least to some extent by market perceptions that Cue Energy remains an attractive takeover target. NZOG's current shareholding will not affect the liquidity of Cue Energy shares, given that it essentially represents the acquisition of an existing substantial shareholding;
- NZOG's shareholding (20.11% as at 26 February 2015) is not an absolute impediment to some alternative change of control transaction involving Cue Energy. Cue Energy's next three largest shareholders collectively hold approximately 36% of the shares in Cue Energy and would be in a position to deliver control of Cue Energy to an alternative bidder. However, it must be recognised that NZOG's shareholding would be a deterrent to an alternative bid for Cue Energy;
- since the announcement of the Offer, Cue Energy shares have generally traded at prices higher than the Offer of 10 cents per share. Between the announcement of the Offer on 12 February 2105 and 26 February 2015, a total of 14,841,119 Cue Energy shares traded at a volume weighted average price of approximately 10.4 cents. Of these, 1,574,993 traded at 10 cents, with the remaining 13,266,126 shares trading at prices higher than 10 cents. Accordingly, Cue Energy shareholders have had an opportunity to realise cash value in excess of the Offer price through selling their shares on market. For as long as Cue Energy shares continue to trade at prices above the Offer price, Cue Energy shareholders have no incentive to sell their shares into the Offer.

Having regard to the above, Grant Samuel has concluded that, on balance, the Offer is not reasonable. Grant Samuel's conclusion could change in different circumstances, including in circumstances in which control had passed to NZOG, the liquidity of Cue Energy shares had been materially affected, or it had become otherwise apparent that Cue Energy shareholders had limited prospects in the short to medium term of realising value greater than the Offer price of 10 cents per share.

Accordingly, in Grant Samuel's view the Offer is neither fair nor reasonable.

4 Other Matters

This report is general financial product advice only and has been prepared without taking into account the objectives, financial situation or needs of individual Cue Energy shareholders. Accordingly, before acting in relation to their investment, shareholders should consider the appropriateness of the advice having regard to their own objectives, financial situation or needs. Shareholders should read the Target's Statement issued by Cue Energy in relation to the Offer.

A decision as to whether to accept the Offer is a matter for individual shareholders, based on their own views as to value, their expectations about future market conditions and their particular circumstances including risk profile, liquidity preference, investment strategy, portfolio structure and tax position. Shareholders who are in doubt as to the action they should take in relation to the Offer should consult their own professional adviser.

Similarly, it is a matter for individual shareholders as to whether to buy, hold or sell securities in Cue Energy. This is an investment decision upon which Grant Samuel does not offer an opinion and is independent of a decision as to whether to accept the Offer. Shareholders should consult their own professional adviser in this regard.

Grant Samuel has prepared a Financial Services Guide as required by the Corporations Act, 2001. The Financial Services Guide is included at the beginning of the full report.

This letter is a summary of Grant Samuel's opinion. The full report from which this summary has been extracted is attached and should be read in conjunction with this summary.

The opinion is made as at the date of this letter and reflects circumstances and conditions as at that date.

Yours faithfully
GRANT SAMUEL & ASSOCIATES PTY LIMITED

Grant Samuel & Associates

Financial Services Guide
and
Independent Expert's Report
in relation to the Offer by
NZOG Offshore Limited

Grant Samuel & Associates Pty Limited
(ABN 28 050 036 372)

28 February 2015

GRANT SAMUEL

GRANT SAMUEL & ASSOCIATES

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Financial Services Guide

Grant Samuel & Associates Pty Limited ("Grant Samuel") holds Australian Financial Services Licence No. 240985 authorising it to provide financial product advice on securities and interests in managed investments schemes to wholesale and retail clients.

The Corporations Act, 2001 requires Grant Samuel to provide this Financial Services Guide ("FSG") in connection with its provision of an independent expert's report ("Report") which is included in a document ("Disclosure Document") provided to members by the company or other entity ("Entity") for which Grant Samuel prepares the Report.

Grant Samuel does not accept instructions from retail clients. Grant Samuel provides no financial services directly to retail clients and receives no remuneration from retail clients for financial services. Grant Samuel does not provide any personal retail financial product advice to retail investors nor does it provide market-related advice to retail investors.

When providing Reports, Grant Samuel's client is the Entity to which it provides the Report. Grant Samuel receives its remuneration from the Entity. In respect of the Report for Cue Energy Resources Limited ("Cue Energy") in relation to the takeover offer by New Zealand Oil & Gas Limited, through its wholly owned subsidiary NZOG Offshore Limited, for all the shares in Cue Energy that it does not already own ("the Cue Energy Report"). Grant Samuel will receive a fixed fee of $200,000 plus reimbursement of out-of-pocket expenses for the preparation of the Report (as stated in Section 7.3 of the Cue Energy Report).

No related body corporate of Grant Samuel, or any of the directors or employees of Grant Samuel or of any of those related bodies or any associate receives any remuneration or other benefit attributable to the preparation and provision of the Cue Energy Report.

Grant Samuel is required to be independent of the Entity in order to provide a Report. The guidelines for independence in the preparation of Reports are set out in Regulatory Guide 112 issued by the Australian Securities & Investments Commission on 30 March 2011. The following information in relation to the independence of Grant Samuel is stated in Section 7.3 of the Cue Energy Report:

> *"Grant Samuel and its related entities do not have at the date of this report, and have not had within the previous two years, any business or professional relationship with Cue Energy, NZOG or NZOG Offshore or any financial or other interest that could reasonably be regarded as capable of affecting its ability to provide an unbiased opinion in relation to the Offer.*
>
> *Grant Samuel will receive a fixed fee of $200,000 for the preparation of this report. This fee is not contingent on the conclusions reached or the outcome of the Offer. Grant Samuel's out of pocket expenses in relation to the preparation of the report will be reimbursed. Grant Samuel will receive no other benefit for the preparation of this report.*
>
> *Grant Samuel had no part in the formulation of the Offer. Its only role has been the preparation of this report.*
>
> *Grant Samuel considers itself to be independent in terms of Regulatory Guide 112 issued by ASIC on 30 March 2011."*

Grant Samuel has internal complaints-handling mechanisms and is a member of the Financial Ombudsman Service, No. 11929. If you have any concerns regarding the Cue Energy Report, please contact the Compliance Officer in writing at Level 19, Governor Macquarie Tower, 1 Farrer Place, Sydney NSW 2000. If you are not satisfied with how we respond, you may contact the Financial Ombudsman Service at GPO Box 3 Melbourne VIC 3001 or 1300 780 808. This service is provided free of charge.

Grant Samuel holds professional indemnity insurance which satisfies the compensation requirements of the Corporations Act, 2001.

Grant Samuel is only responsible for the Cue Energy Report and this FSG. Complaints or questions about the Disclosure Document should not be directed to Grant Samuel which is not responsible for that document. Grant Samuel will not respond in any way that might involve any provision of financial product advice to any retail investor.

GRANT SAMUEL

Table of Contents

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1 Details of the Offer

On 22 December 2014, New Zealand Oil & Gas Limited ("NZOG"), through its wholly owned subsidiary NZOG Offshore Limited ("NZOG Offshore"), announced that it had acquired 139,554,132 shares in Cue Energy Resources Limited ("Cue Energy") representing 19.99% of Cue Energy's shares on issue. The shares were acquired off-market on 19 December 2014 from The Todd Corporation at 10 cents[1] a share.

On 12 February 2015, NZOG announced that, through NZOG Offshore, it was making an on-market takeover offer ("Offer") of 10 cents cash per share for all the shares in Cue Energy that it did not already own. On the same date, the Board of Cue Energy advised Cue Energy shareholders to reject the offer and not to sell their Cue Energy shares on-market at the offer price of 10 cents a share.

The Bidder's Statement was lodged with the Australian Securities and Investments Commission ("ASIC") and sent to the Australian Securities Exchange ("ASX") on 12 February 2015, and dispatched to Cue Energy shareholders on 23 February 2015.

NZOG is an oil and gas exploration and production company with producing assets in the offshore Taranaki basin in New Zealand and exploration interests in New Zealand and Indonesia. The company is listed on the New Zealand Stock Exchange and the ASX and had a market capitalisation of approximately $210 million on 26 February 2015.

The Offer is unconditional, including in relation to NZOG Offshore's ultimate shareholding in Cue Energy at the end of the offer period. NZOG Offshore states in the Bidder's Statement that it seeks to increase its shareholding in Cue Energy to a level where it can exert greater influence on the direction of the company and that it would be comfortable if it can acquire at least a further 10% in Cue Energy.

NZOG Offshore has stated that the Offer price will not be increased during the Offer period in the absence of a competing proposal. In any event, as the Offer is an on-market takeover offer, Cue Energy shareholders who have sold into the Offer will not benefit from any subsequent increase in the Offer price.

The Offer opens on 27 February 2015, although Cue Energy shareholders have been able to sell shares into the Offer since lodgement of the Bidder's Statement on 12 February 2015. The Offer closes on 27 March 2015 unless withdrawn or extended prior to closing.

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1 All references to dollars relate to Australian dollars unless otherwise specified.

2 Scope of the Report

2.1 Purpose of the Report

Although there is no requirement in the present circumstances for an independent expert's report pursuant to the Corporations Act or the ASX Listing Rules, the directors of Cue Energy have engaged Grant Samuel & Associates Pty Limited ("Grant Samuel") to prepare an independent expert's report setting out whether, in its opinion, the Offer is fair and reasonable to Cue Energy shareholders and to state reasons for that opinion. A copy of the report will accompany the Supplementary Target's Statement to be sent to shareholders by Cue Energy.

This report is general financial product advice only and has been prepared without taking into account the objectives, financial situation or needs of individual Cue Energy shareholders. Accordingly, before acting in relation to their investment, shareholders should consider the appropriateness of the advice having regard to their own objectives, financial situation or needs. Shareholders should read the Bidder's Statement issued by NZOG Offshore and the Target's Statement and Supplementary Target's Statement issued by Cue Energy in relation to the Offer.

Whether or not to accept the Offer is a matter for individual shareholders based on their views as to value, their expectations about future market conditions and their particular circumstances including risk profile, liquidity preference, investment strategy, portfolio structure and tax position. Shareholders who are in doubt as to the action they should take in relation to the Offer should consult their own professional adviser.

Similarly, it is a matter for individual shareholders as to whether to buy, hold or sell securities in Cue Energy or NZOG. These are investment decisions upon which Grant Samuel does not offer an opinion and independent of a decision on whether to accept the Offer. Shareholders should consult their own professional adviser in this regard.

2.2 Basis of Evaluation

The term "fair and reasonable" has no legal definition although over time a commonly accepted interpretation has evolved. However, ASIC has issued Regulatory Guide 111 which establishes guidelines in respect of independent expert's reports. ASIC Regulatory Guide 111 differentiates between the analysis required for control transactions and other transactions. In the context of control transactions (whether by takeover bid, by scheme of arrangement, by the issue of securities or by selective capital reduction or buyback), the expert is required to distinguish between "fair" and "reasonable".

Fairness involves a comparison of the offer price with the value that may be attributed to the securities that are the subject of the offer based on the value of the underlying businesses and assets. For this comparison, value is determined assuming 100% ownership of the target and a knowledgeable and willing, but not anxious, buyer and a knowledgeable and willing, but not anxious, seller acting at arm's length. Reasonableness involves an analysis of other factors that shareholders might consider prior to accepting an offer such as:

- the offeror's existing shareholding;
- other significant shareholdings;
- the probability of an alternative offer; and
- the liquidity of the market for the target company's shares.

An offer could be considered "reasonable" if there were valid reasons to accept the offer notwithstanding that it was not "fair".

Fairness is a more demanding criteria. A "fair" offer will always be "reasonable" but a "reasonable" offer will not necessarily be "fair". A fair offer is one that reflects the full market value of a company's businesses and assets. An offer that is in excess of the pre-bid market prices but less than full value will not be fair but may be reasonable if shareholders are otherwise unlikely in the foreseeable future to realise an amount for their shares in excess of the offer price. This is commonly the case where the bidder already controls the target company. In that situation the minority shareholders have little prospect of receiving full value from a third party offeror unless the controlling shareholder is prepared to sell its controlling shareholding.

Grant Samuel has determined whether the Offer is fair by comparing the estimated underlying value range of Cue Energy with the offer price. The Offer will be fair if it falls within the estimated underlying value range. In considering whether the Offer is reasonable, the factors that have been considered include:

- the estimated value of Cue Energy compared to the offer price;
- the existing shareholding structure of Cue Energy;
- the likelihood of an alternative offer and alternative transactions that could realise fair value;
- the likely market price and liquidity of Cue Energy shares in the absence of the Offer; and
- other advantages and disadvantages for Cue Energy shareholders of accepting the Offer.

2.3 Sources of the Information

The following information was utilised and relied upon, without independent verification, in preparing this report:

Publicly Available Information

- the Bidder's Statement;
- the Target's Statement and the Supplementary Target's Statement (including earlier drafts);
- annual reports of Cue Energy for the three years ended 30 June 2014;
- half year announcement of Cue Energy for the six months ended 31 December 2014;
- press releases, public announcements, media and analyst presentation material and other public filings by Cue Energy including information available on its website;
- brokers' reports and recent press articles on Cue Energy and the oil and gas industry;
- sharemarket data and related information on Australian and international listed companies engaged in the oil and gas industry; and
- information relating to the international oil and gas sector including supply/demand and oil price forecasts.

Non Public Information provided by Cue Energy

- detailed cash flows models including projections for Cue Energy's producing assets;
- studies and other technical information relating to Cue Energy's assets; and
- other confidential documents, board papers, presentations and working papers.

In preparing this report, Grant Samuel has held discussions with, and obtained information from, senior management of Cue Energy and its advisers. Grant Samuel appointed a technical adviser, RISC Operations Pty Ltd ("RISC") to provide certain technical advice to Grant Samuel in relation to the preparation of this report.

2.4 Limitations and Reliance on Information

Grant Samuel believes 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 employed and the conclusions reached. Any attempt to do so could lead to undue emphasis on a particular factor or analysis. The preparation of an opinion is a complex process and is not necessarily susceptible to partial analysis or summary.

Grant Samuel's opinion is based on economic, sharemarket, business trading, financial and other conditions and expectations prevailing at the date of this report. These conditions can change significantly over relatively short periods of time. If they did change materially, subsequent to the date of this report, the opinion could be different in these changed circumstances.

This report is also based upon financial and other information provided by Cue Energy and its advisers. Grant Samuel has considered and relied upon this information. Cue Energy has represented in writing to Grant Samuel that to its knowledge the information provided by it was then, and is now, complete and not incorrect or misleading in any material respect. Grant Samuel has no reason to believe that any material facts have been withheld.

The information provided to Grant Samuel has been evaluated through analysis, inquiry and review to the extent that it considers necessary or appropriate for the purposes of forming an opinion as to whether the Offer is fair and reasonable to Cue Energy shareholders. However, Grant Samuel does not warrant that its inquiries have identified or verified all of the matters that an audit, extensive examination or "due diligence" investigation might disclose. While Grant Samuel has made what it considers to be appropriate inquiries for the purposes of forming its opinion, "due diligence" of the type undertaken by companies and their advisers in relation to, for example, prospectuses or profit forecasts, is beyond the scope of an independent expert.

Accordingly, this report and the opinions expressed in it should be considered more in the nature of an overall review of the anticipated commercial and financial implications rather than a comprehensive audit or investigation of detailed matters.

An important part of the information used in forming an opinion of the kind expressed in this report is comprised of the opinions and judgement of management. This type of information was also evaluated through analysis, inquiry and review to the extent practical. However, such information is often not capable of external verification or validation.

Preparation of this report does not imply that Grant Samuel has audited in any way the management accounts or other records of Cue Energy. It is understood that the accounting information that was provided was prepared in accordance with generally accepted accounting principles and in a manner consistent with the method of accounting in previous years (except where noted).

RISC was appointed as technical specialist to review the assets of Cue Energy for Grant Samuel. RISC's review included a review of the reserves, development plans, production schedules, operating costs, capital costs, potential reserve extensions and exploration activities of Cue Energy. RISC also prepared valuations of Cue Energy's exploration interests. The report prepared by RISC is attached to and forms part of this report (see Appendix 3).

The information provided to Grant Samuel and RISC included development plans and forecasts for Cue Energy's key assets. Cue Energy is responsible for the information contained in the development plans and forecasts (the "forward looking information"). Grant Samuel and RISC have considered and, to the extent deemed appropriate, relied on this information for the purpose of their analysis.

On the basis of the information provided to Grant Samuel and RISC, and the review conducted by Grant Samuel and RISC of such information, Grant Samuel and RISC have concluded that the forward looking information was prepared appropriately and accurately based on the information available to management at the time and within the practical constraints and limitations of such forward looking information. Grant Samuel and RISC have concluded that the forward looking information does not reflect any material bias, either positive or negative. Grant Samuel has no reason to believe otherwise. However, the achievability of the forward looking information is not warranted or guaranteed by Grant Samuel. Future profits and cash flows are inherently uncertain. They are predictions by management of future events that cannot be assured and are not necessarily based on assumptions, many of which are beyond the control of the company or its management. Actual results may be significantly more or less favourable. Moreover, the forward looking information provided by Cue Energy was not originally generated for, and may not be appropriate in the context of, a valuation of the assets of Cue Energy.

Accordingly, RISC conducted a detailed review of the significant assumptions and technical factors underlying the forward looking information provided by Cue Energy to RISC and Grant Samuel. This review included a review of the basis on which reserves and resources have been estimated, a review of likely future operating and capital costs, a review of likely future hydrocarbon recovery rates, a review of the potential for the conversion of resources to reserves and such other reviews as RISC deemed appropriate. Having regard to these reviews, RISC made independent judgements regarding the technical assumptions that can reasonably be adopted for the purposes of the valuation of the assets of Cue Energy ("technical valuation assumptions").

As part of its analysis, Grant Samuel has developed cash flow models on the basis of the technical valuation assumptions deemed appropriate by RISC. Grant Samuel has reviewed the sensitivity of net present values to changes in key variables. The sensitivity analysis isolates a limited number of assumptions and shows the impact of the expressed variations to those assumptions. No opinion is expressed as to the probability or otherwise of those expressed variations occurring. Actual variations may be greater or less than those modelled. In addition to not representing best and worst case outcomes, the sensitivity analysis does not, and does not purport to, show all the possible variations to the business model. The actual performance of the business may be negatively or positively impacted by a range of factors including, but not limited to:

- changes to the assumptions other than those considered in the sensitivity analysis;
- greater or lesser variations to the assumptions considered in the sensitivity analysis than those modelled; and
- combinations of different assumptions may produce outcomes different to those modelled.

In forming its opinion, Grant Samuel has also assumed that:

- matters such as title, compliance with laws and regulations and contracts in place are in good standing and will remain so and that there are no material legal proceedings, other than as publicly disclosed;
- the assessments by Cue Energy and its advisers with regard to legal, regulatory, tax and accounting matters relating to the transaction are accurate and complete;
- the information set out in the Target's Statement and the Supplementary Target's Statement sent by Cue Energy to its shareholders is complete, accurate and fairly presented in all material respects;
- the publicly available information relied on by Grant Samuel in its analysis was accurate and not misleading;
- the Offer will be implemented in accordance with its terms; and
- the legal mechanisms to implement the Offer are correct and will be effective.

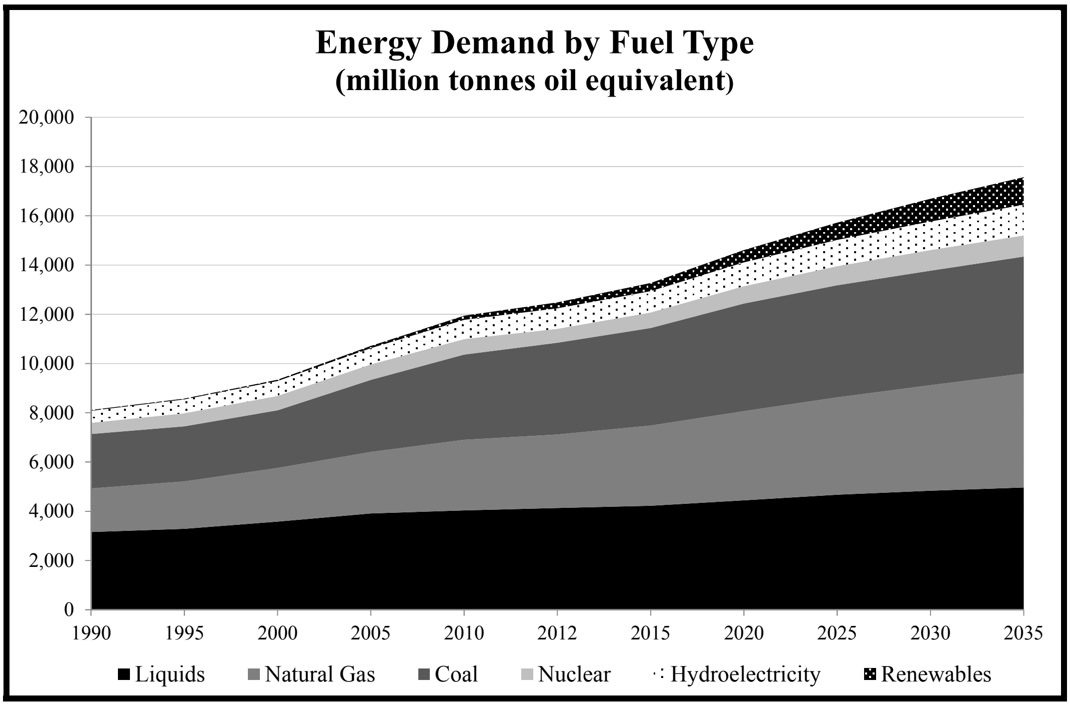
To the extent that there are legal issues relating to assets, properties, or business interests or issues relating to compliance with applicable laws, regulations, and policies, Grant Samuel assumes no responsibility and offers no legal opinion or interpretation on any issue.

3 Overview of the Oil Industry

3.1 Global Energy Market

World energy consumption has increased by an average of 2.0% per annum since 1990 and is expected to grow on average by 1.5% per annum to 2035[2]. Most of the world's energy requirements are met from five major sources (oil, coal, natural gas, nuclear and hydroelectricity) although renewable sources of energy are increasing in importance. Recent years have seen high and volatile world energy prices, reflecting growth in global energy demand, an increasing reliance on high cost energy sources, changing geopolitical circumstances, the impact of policy responses to concerns related to climate change, and unsettled economic conditions. The consequences have included increased demand worldwide for natural gas and the growth of renewable energy sources.

Since 1990 consumption of both coal and natural gas has grown on average by 2.4% per annum while growth in oil consumption has been slower at 1.2% per annum. As a consequence, oil's share of global energy consumption has declined from around 39% in 1990 to 33% in 2012 and is expected to fall further to around 28% in 2035. Nevertheless, it will remain an important source of energy, with oil consumption forecast to grow at around 0.8% per annum to 2035. At the same time consumption of natural gas is expected to grow at 1.9% per annum, with its share of consumption expected to increase from 24% in 2012 to around 26% in 2035. Although it will remain a relatively small component of the global energy mix, energy from renewable sources is expected to grow at 6.4% p.a., representing the highest growth rate amongst the major energy categories. World energy demand totalled approximately 12,500 million tonnes of oil equivalent in 2012:



Source: *"BP Energy Outlook 2035"*, BP plc, January 2014

Asia Pacific accounted for 40% of global energy demand in 2012, more than half of which relates to China, while North America and Europe & Eurasia each contributed one quarter. The Asia Pacific region is forecast to make up the majority of the growth in demand to 2035, with the Middle East, South & Central America and Africa expected to contribute most of the balance. North America and Europe & Eurasia are expected to contribute only marginally to global energy

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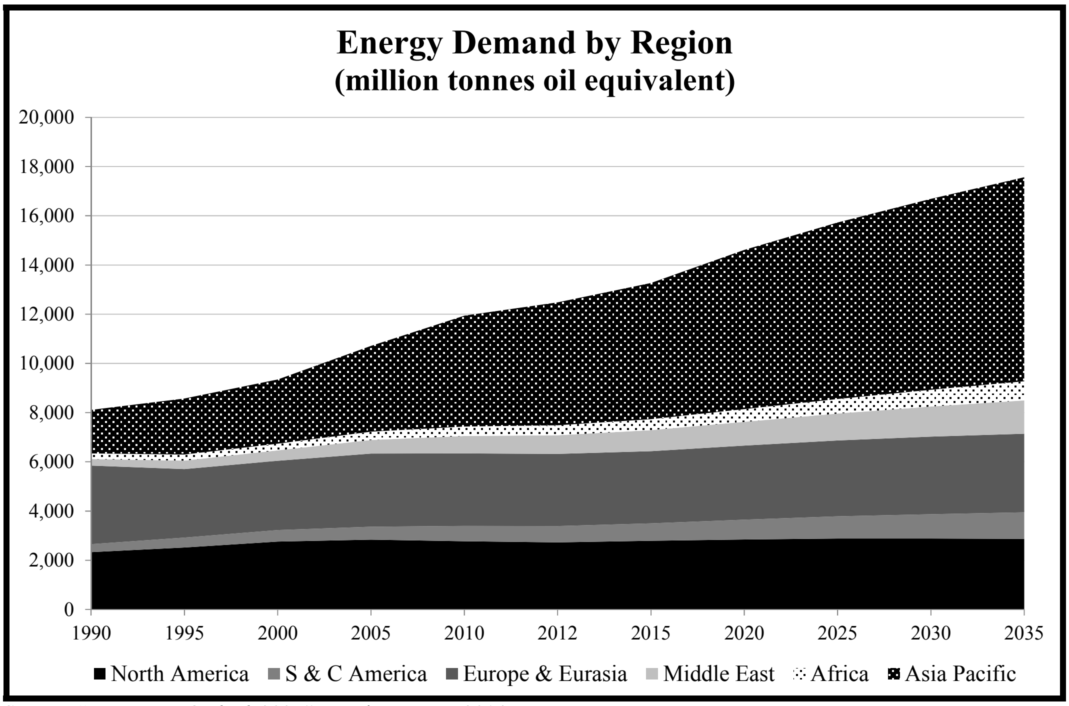
2 The major sources of statistical data in the report on the energy sector are "*BP Statistical Review of World Energy June 2013"*, BP plc. and *"BP Energy Outlook 2035"*, BP plc., January 2014.

demand growth, which would result in their share of global energy demand falling from 45% in 2012 to 35% by 2035:



Source: *"BP Energy Outlook 2035"*, BP plc, January 2014

China and India are expected to be the two countries that contribute most to growth in energy demand. China will have the largest impact on energy demand, due both to its absolute size and its rate of economic growth, which is expected to be the highest of any county over the next two decades. While the Indian economy is smaller, it is expected to reach growth rates similar to China's in the period 2025-2035 and therefore become an increasingly important contributor to global energy demand growth.

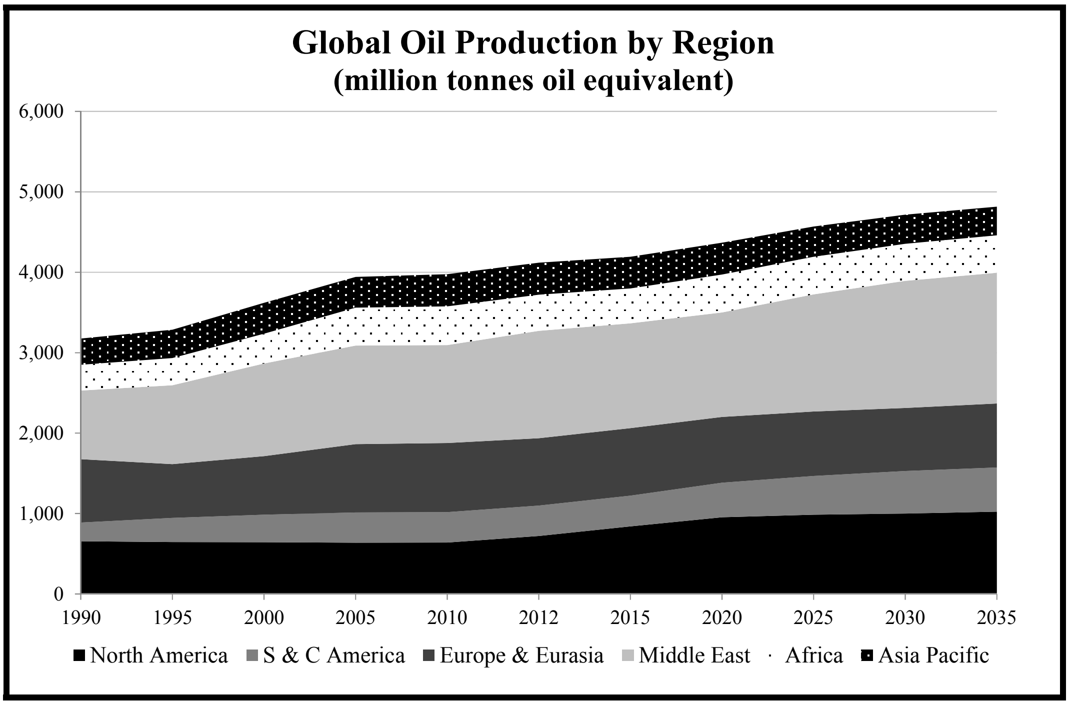
Energy demand growth is in large part a function of the industrialisation and electrification of growing economies. Analysts are forecasting a gradual diminution in the impact of these factors, as developing economies approach economic maturity, and lower energy intensities are required per unit of GDP.

3.2 Oil Supply and Demand

Oil's primary use is as transport fuel, mostly for road motor vehicles. The production of oil is heavily influenced by the Organisation of Petroleum Exporting Countries ("OPEC"), an intergovernmental organisation of 12 oil-exporting developing nations that coordinates and unifies the petroleum policies of its member countries[3].

Global oil production since 1990 and projected oil production to 2035 are illustrated below:

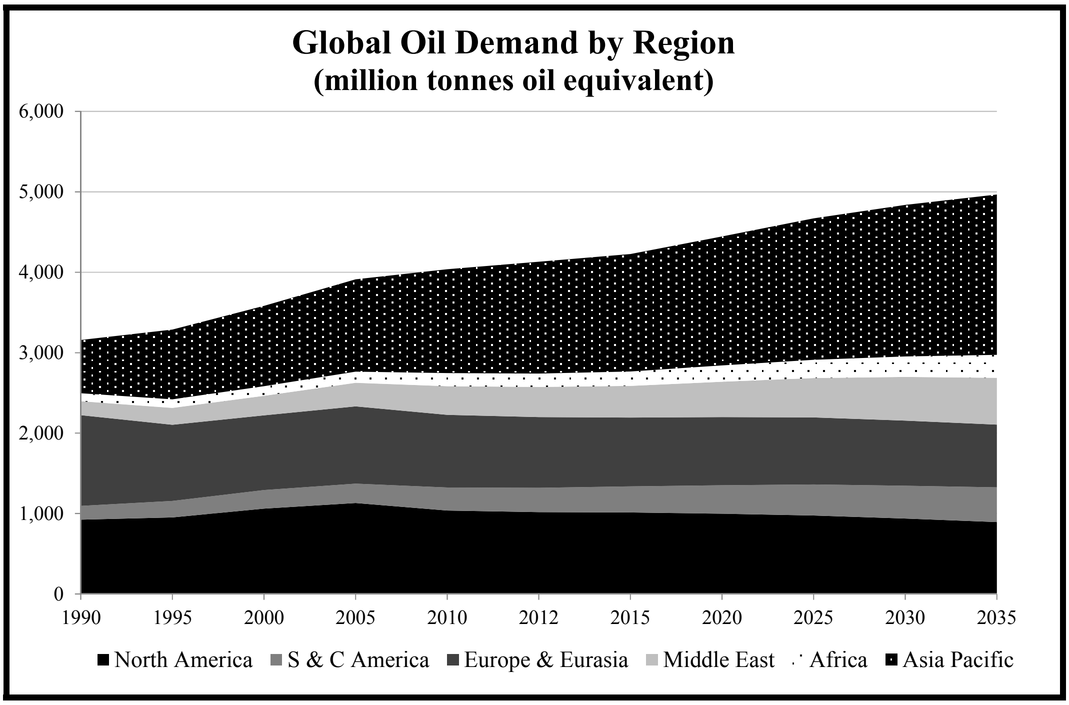
[3] Members: Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, Venezuela.



Source: *"BP Energy Outlook 2035"*, BP plc, January 2014

Between 1990 and 2012, oil production increased by 1.2% per annum. This growth was largely the result of increased production from the Middle East and Central and South America. Global oil production growth between 2012 and 2035 is expected to be lower at an average of around 0.7% per annum: higher growth rates from North America (1.5% per annum) and South and Central America (1.6% per annum) are expected to offset production declines in Europe and Asia. The expected increase in North American supply reflects technological advances that have improved the economic viability of unconventional oil sources such as shale oil and tight oil (although the recent significant falls in the oil price will affect the economics of many unconventional hydrocarbon producers and may temper the rate of growth of supply). Growth in South and Central America is expected to result from new discoveries and developments, particularly in Brazil. Production from OPEC is expected to be relatively flat over this period.

Although the North American market has historically been the largest consumer of oil, it was overtaken by the Asia Pacific region around 2005. By 2035, oil consumption in the Asia Pacific region is expected to be more than double the consumption in North America, reflecting increased demand in China and India, particularly for use in transport. Over the same period, oil consumption in North America and Europe & Eurasia is expected to decline.



Source: *"BP Energy Outlook 2035"*, BP plc, January 2014

3.3 Oil Price

Oil is one of the most heavily traded commodities in the world. Prices are typically set against one of the following two international benchmarks and are adjusted to reflect the specific characteristics of the products and the location of the ports of origin and destination:

- West Texas Intermediate ("WTI"), a light, sweet crude oil, is the primary benchmark for oil produced in the United States. Cushing, Oklahoma, is a major hub and delivery location for WTI and represents the settlement point for WTI. Futures contracts on WTI are traded on NYMEX[4]; and

- Dated Brent ("Brent"), which is also a light crude oil, although not as light as WTI, is a composite blend of oils from 15 different oilfields in the North Sea. It has historically been used as a crude oil benchmark primarily within Europe. However, the impact on WTI pricing of United States market specific factors has reduced the relevance of WTI as an international benchmark, and instead Brent is increasingly being used as a global benchmark price for oil.

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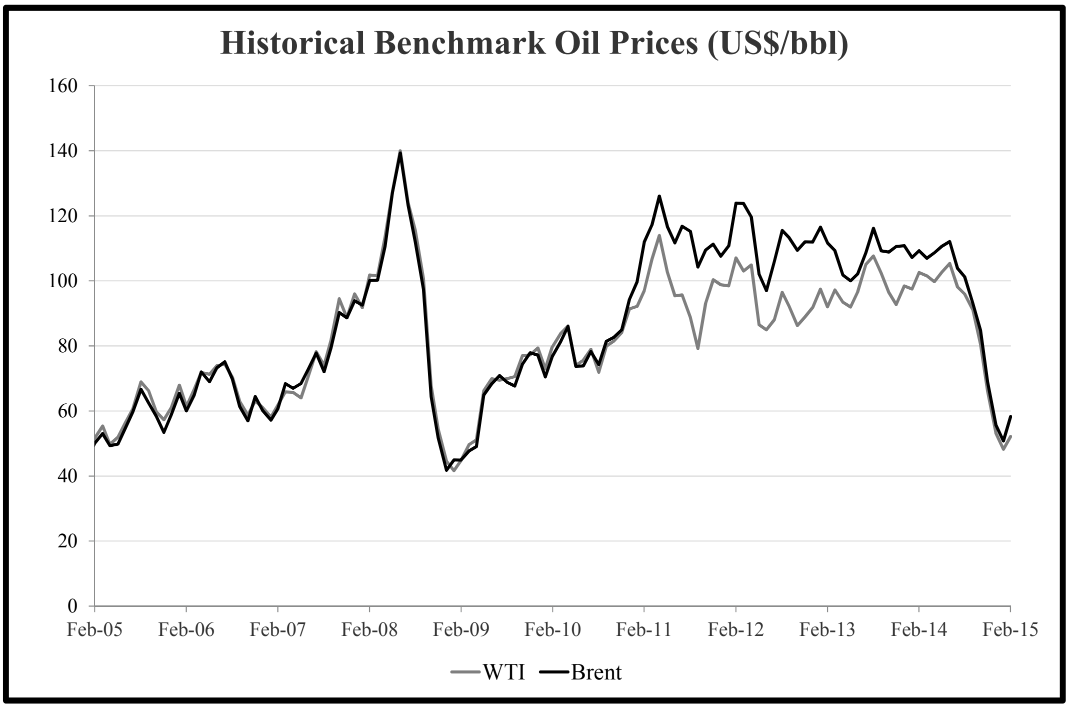
4 A designated contract market operated by CME Group that offers derivative products subject to NYMEX rules and regulations.

The Brent and WTI oil prices over the past ten years are illustrated below:

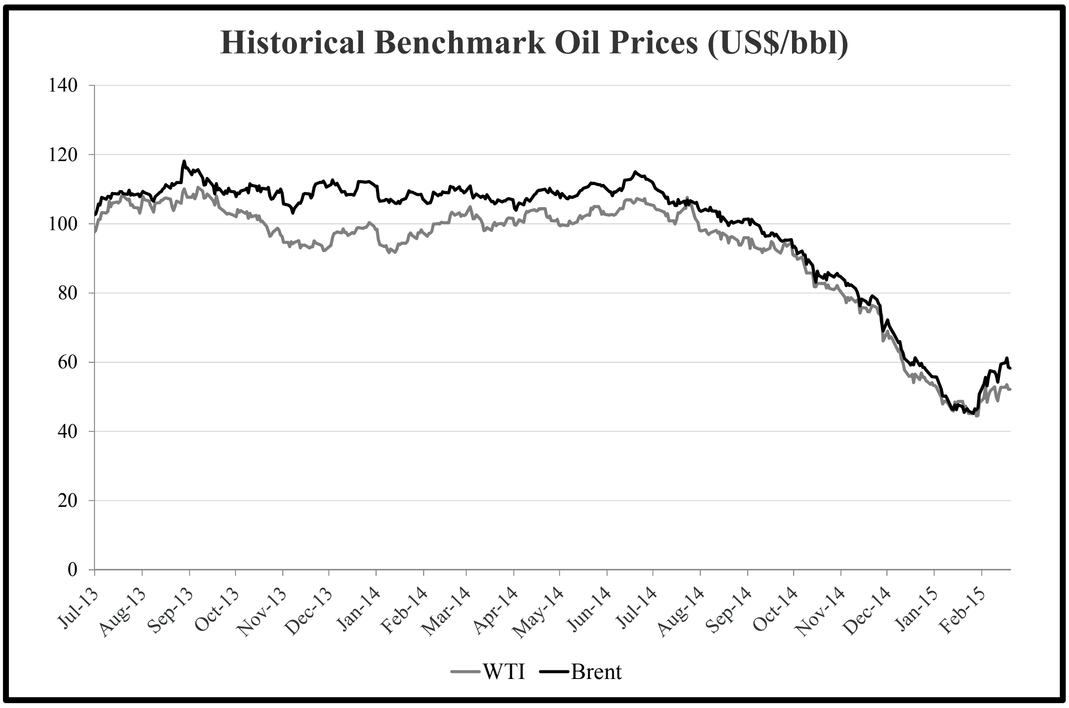


Source: Bloomberg

The oil price has fluctuated dramatically over the past decade. The oil price trended up in the five years to July 2008 despite the global financial crisis of late 2007 and the first half of 2008. However, weaker economic conditions eventually affected oil markets and the Brent oil price fell from a high of US$145/bbl in early July 2008 to US$31/bbl in late December 2008. Between December 2008 and July 2014, the oil price slowly recovered and Brent oil traded broadly in the US$100-125/bbl range in 2011, 2012, 2013 and the first six months of 2014. Key to this recovery was OPEC's decision to limit production, as well as increasing demand from developing countries in Asia.

After trading within a fairly narrow range for most of the year ended 30 June 2014 (US$105-115/bbl for Brent and US$95-105/bbl for WTI), the oil price fell sharply from late June 2014 to January 2015, reflecting amongst other factors concerns about slowing demand growth and a decision by Saudi Arabia to maintain production volumes notwithstanding market weakness. The oil price reached lows not experienced since early 2009: the WTI oil price reached a low of US$44.45/bbl on 28 January 2015 and the Brent oil price a low of US$45.25/bbl on 26 January 2015. Since then, the oil has partially recovered, with Brent closing at US$58.53/bbl and WTI closing at US$52.14/bbl on 18 February 2015.

The WTI and Brent benchmarks have historically traded broadly in line with each other. However, an increase in US production combined with a shortage of pipeline capacity to transport the oil to US refiners has led to a build-up of US inventories, with the result that WTI has generally traded at a discount to Brent over the past three years. The daily Brent and WTI oil prices since 1 July 2013 are illustrated below:



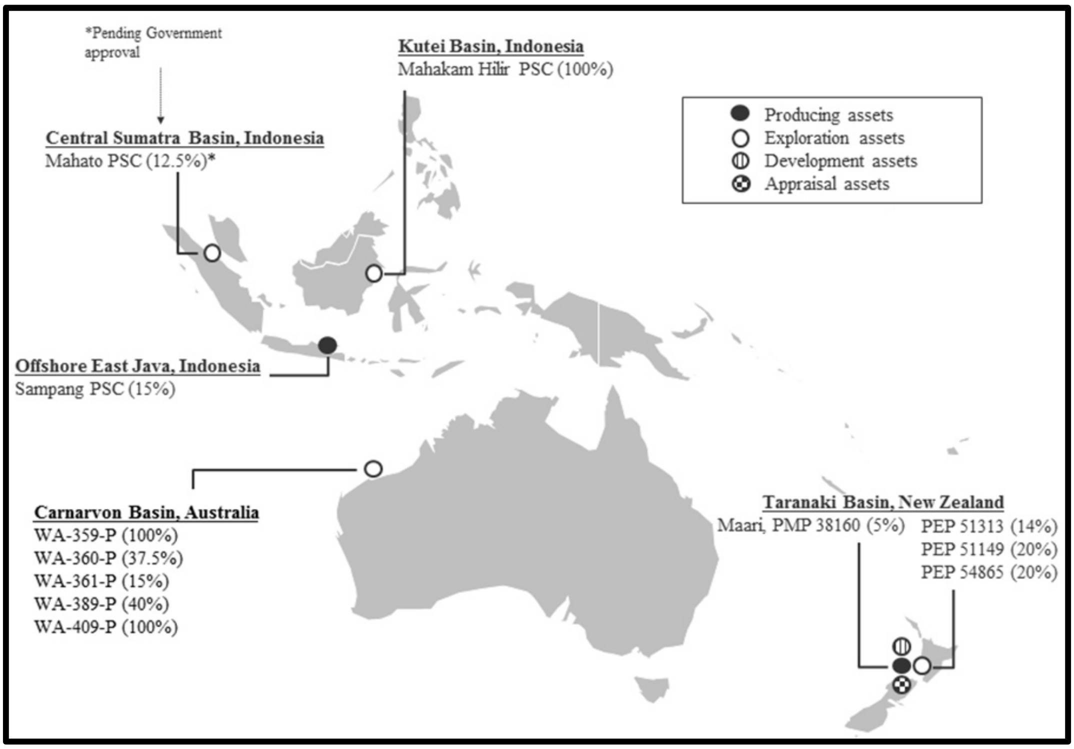
Source: Bloomberg

4 Profile of Cue Energy

4.1 Background

Established in 1981, Cue Energy is an oil and gas exploration and production company with a focus on South East Asia and Australasia. It listed on ASX in 1995 and is headquartered in Melbourne. Cue Energy had a market capitalisation of around $63 million immediately before the announcement of the Offer on 12 February 2015.

Cue Energy has petroleum assets in New Zealand, Indonesia and Australia, having recently completed the divestment of its portfolio of assets in Papua New Guinea:



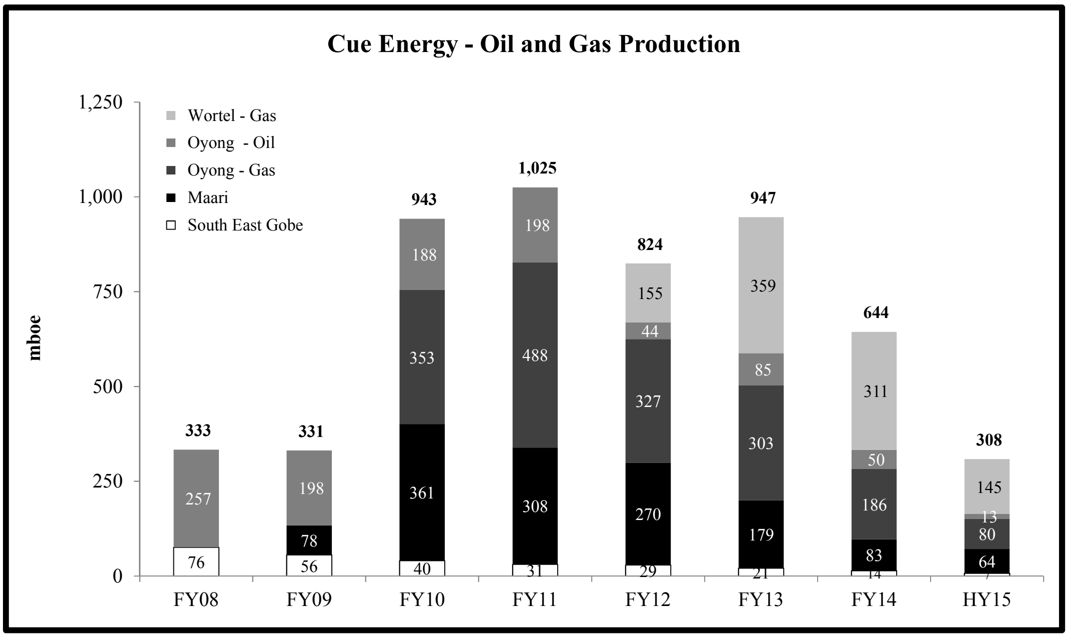
Source: Cue Energy

Cue Energy has interests in two producing permits:

- a 5% interest in PMP 38160, which hosts the Maari and Manaia oil fields in the offshore Taranaki Basin in New Zealand; and
- a 15% interest in the Sampang PSC, which covers the Wortel gas field and Oyong oil field offshore East Java in Indonesia.

In addition, it has exploration interests in the Carnarvon Basin in Western Australia, the Kutei Basin and Central Sumatra Basin in Indonesia and the Taranaki Basin in New Zealand.

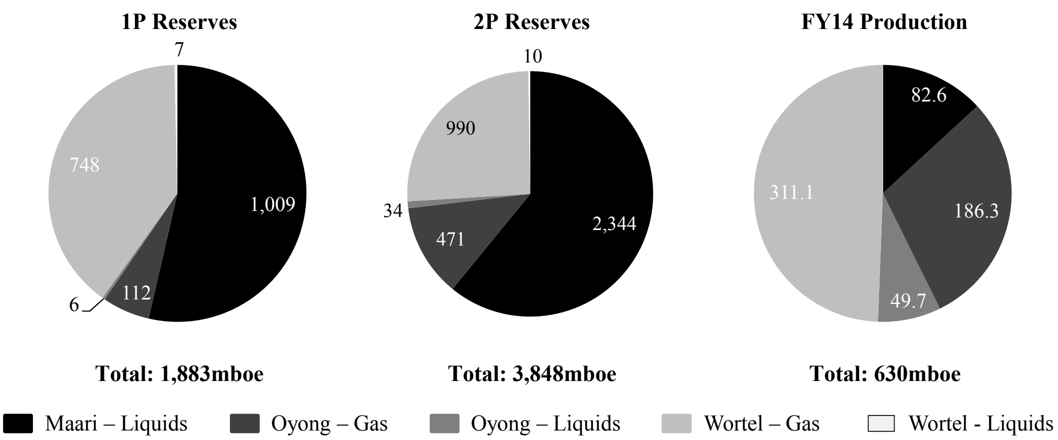
Cue Energy's annual production volumes since 2007 have fluctuated, reflecting the production profiles of its producing assets:



Source: Cue Energy

Cue Energy has a net interest in 1P reserves of 1.883mmboe of oil and gas and 2P reserves of 3.848mmboe of oil and gas[5]. Its net share of petroleum production in the year ended 30 June 2014 ("FY14") was 630mboe for current fields[6]. The breakdown of reserves and FY14 production by field and product for current assets is shown below:

Cue Energy – Reserves and FY14 Production[7]



Source: Cue Energy

Cue Energy also booked 2C resources of 1.244mmbbl of oil through its 8.18% stake in the Jeruk exploration play in Indonesia.

5 Based on reserves as at 31 December 2013 but excluding the contribution from the Papua New Guinea assets which Cue Energy sold in December 2014.

6 Excluding the contribution from the Papua New Guinea assets which Cue Energy sold in December 2014.

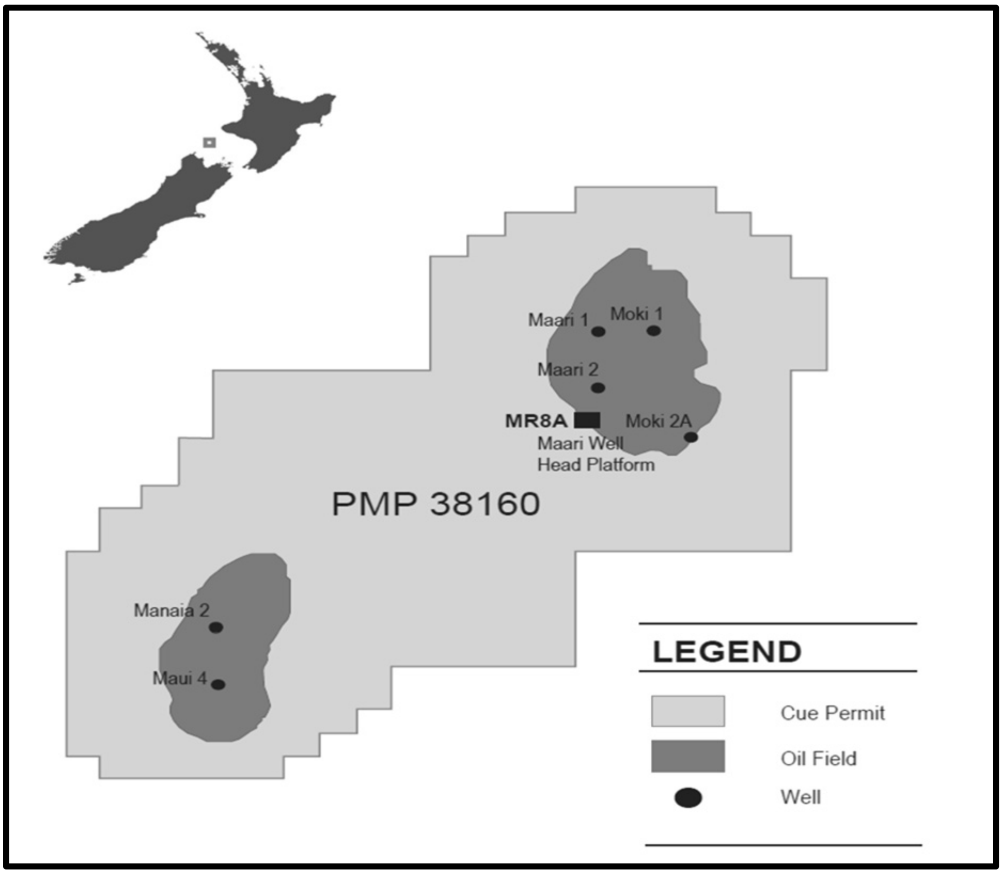
7 Numbers may not add to total due to rounding.

4.2 Oil and Gas Assets

4.2.1 Maari/Manaia

Overview

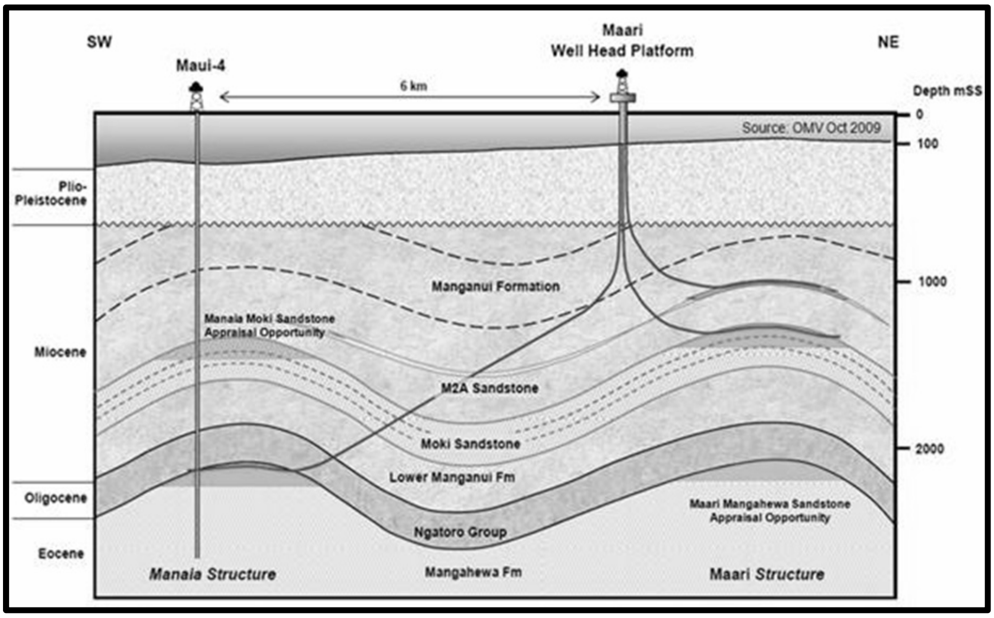
Cue Energy holds a 5% interest in the PMP 38160 permit, which hosts the Maari and Manaia producing oil fields located in the Taranaki Basin in the Tasman Sea. The fields are located 80 km offshore the south Taranaki coast of New Zealand in approximately 100 metres of water:



Source: Cue Energy

Cue Energy's joint venture partners in the permit are OMV New Zealand Ltd ("OMV", 69% and operator), Todd Exploration Limited (16%), and the ASX listed Horizon Oil Limited (10%).

The Maari and Manaia fields currently source oil from several reservoirs hosted by different formations at depths of up to 2,100 metres:



Source: Cue Energy

The infrastructure associated with PMP 38160 includes the Maari wellhead platform, a joint venture owned floating production, storage and offloading ("FPSO") vessel, seven production and one water injector well and associated sub-sea flow lines. Oil is loaded onto tankers for delivery to refineries in Australia and South East Asia. The oil is sold at a premium to the Brent Crude oil price benchmark reflecting the high quality of the oil produced. The premium has fluctuated between approximately US$2.00 and US$6.00 per barrel over the past year but was fairly consistently around US$4.00 from 2011 to 2013.

Resources and Reserves

Cue Energy reported the following reserves (and no contingent resources) as at 31 December 2013:

PMP 38160 – Reserves at 31 December 2013 (Cue Energy Share)		
	Proved (1P)	Proved + Probable (2P)
Oil (mmbbl)	1.009	2.344

Source: Cue Energy

Production

First production from the Maari-Manaia fields occurred in February 2009. Cue Energy's share of production from PMP 38160 from commencement of production to 31 December 2014 is summarised below:

PMP 38160 – Production (Cue Energy Share)							
	Year ended 30 June						Six months ended
	2009 actual	2010 actual	2011 actual	2012 actual	2013 actual	2014 actual	31 Dec 2014 actual
Oil (mbbl)	78.0	360.8	308.0	269.7	178.9	82.6	64.0

Source: Cue Energy

The production reflects the natural decline of the field as well as interruptions to existing production through development drilling in the six months to December 2014. Production in FY14 was also affected by the loss of 145 days of production from July to December 2013, while unplanned repairs to the swivel and mooring systems of the FPSO were undertaken. The total cost of the works was approximately US$80 million (100%), some of which has been or will be recovered under insurance claims.

Field Development

The Maari Growth Project aimed to increase production through the drilling of one production well at each of Maari and Manaia to exploit reservoirs in the Mangahewa formation and two production wells and one water injection well at Maari, targeting reservoirs hosted in the Moki formation. The project was sanctioned in July 2013 and was expected to be completed by the end of 2014 at a cost of NZ$354 million, the majority of which was to be spent on drilling.

However, the project has experienced operational issues resulting in delays, cost overruns and deferred production. Production from the first well (MR8A) was achieved in November 2014, at lower than expected production rates. Drilling of a second well (MR6A) was suspended because of drilling conditions but this well has since been re-entered and is currently being drilled. The joint venture is considering two to three further production wells, one of which will be converted into a water injector in the future. In addition to the planned loss of production because of the requirement to temporarily shut producing wells, the MR3 well was damaged by drilling fluids and experienced reduced production until the electric submersible pump failed, causing the well to be shut in. A workover of the existing MR5A well has been completed and further workovers are scheduled immediately after the drilling campaign, to perform maintenance on the MR3 and MR9 wells and access additional pay behind pipe in MR8A.

Overall, the slower than expected progress on the project is likely to defer expected new production for FY15 and final production rates will remain uncertain until the completion of the programme and workovers.

The current estimated final cost of the project is US$387 million (at current exchange rates approximately NZ$515 million).

New Zealand Oil and Gas Fiscal Regime

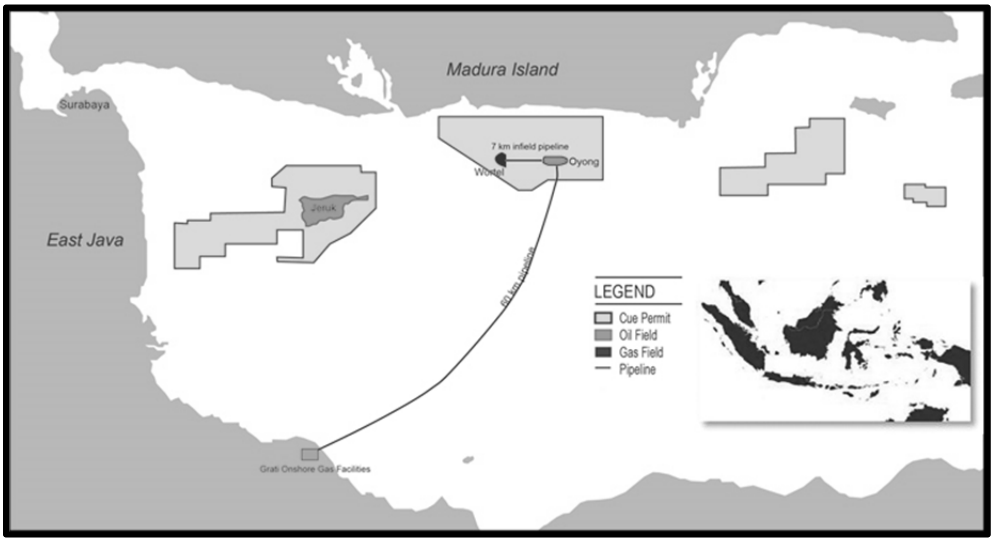
Petroleum projects in New Zealand are subject to the following fiscal terms:

- royalties are payable, calculated as the greater (on an annual basis) of:
  - ad valorem royalty ("AVR") which is calculated as 5% of the sales revenue;
  - accounting profits royalty ("APR"), which is essentially 20% of the amount calculated by subtracting operating and capital expenditure from sales revenue ;
- the corporate tax rate is 28%; and
- there are no withholding taxes on cash repatriated to Australia.

4.2.2 Sampang PSC

Overview

Cue Energy has a 15% stake in the Sampang Production Sharing Contract ("PSC"). The joint venture partners are Santos (Sampang) Pty Ltd (45% and operator), a subsidiary of Santos Limited and Singapore Petroleum Sampang Ltd (40%), a subsidiary of Singapore Petroleum Company Limited. The Sampang PSC covers both the Oyong oil field and the Wortel gas field, which are located in 45 metres of water offshore East Java in Indonesia.



Source: Cue Energy

The infrastructure associated with the Sampang PSC consists of:

- processing facilities supporting 11 wells at Oyong;
- a leased production barge and floating storage and offloading vessel ("FSO") at Oyong;
- the unmanned Wortel wellhead platform, which supports two wells;
- an onshore gas processing facility located in Grati in East Java; and
- a 10km pipeline linking Wortel to the Oyong facilities and a 60km pipeline linking Oyong to the Grati plant.

Reserves

As at 31 December 2013, Cue Energy reported the following reserves at Oyong:

Sampang PSC – Reserves at 31 December 2013 (Cue EnergyShare)[8]

	Proved (1P)			Proved + Probable (2P)		
	Liquids (mmbbl)	**Gas** (Bscf)	**Total** (mmboe)	**Liquids** (mmbbl)	**Gas** (Bscf)	**Total** (mmboe)
Oyong	0.006	0.673	0.119	0.034	2.825	0.504
Wortel	0.007	4.490	0.755	0.010	5.940	1.000

Source: Cue Energy

Oyong Production

Oyong yields oil with some associated gas and minimal amounts of condensate. Oil was first produced at Oyong in September 2007 and gas in October 2009. Cue Energy's share of production since the commencement of operation is set out below:

8 Net of Indonesian government share of production.

Oyong – Production (Cue Energy Net Share)								
	Year ended 30 June							Six months ended
	2008 actual	2009 actual	2010 actual	2011 actual	2012 actual	2013 actual	2014 actual	31 Dec 2014 actual
Oil (mbbl)	257.2	197.6	188.1	197.7	44.2	85.4	49.7	13.1
Gas (MMscf)	-	-	2,120	2,930	1,960	1,816	1,118	477

Source: Cue Energy

Production volumes over the period reflect the maturation of the fields. A well workover programme is currently underway with one well currently being brought back into production. The workovers are expected to lead to higher oil recoveries with the potential to prolong production for one to two years until 2017.

The oil produced at Oyong is generally sold at a premium to the Indonesian Ardjuna benchmark, which has historically been equivalent to a price slightly lower than the Brent Crude oil price. The gas is sold at contracted prices with some escalation (not linked to oil prices), under a long term contract to a local power generator owned by PT Indonesia Power.

Wortel Production

Wortel produces gas with small amounts of condensate, which is sold together with the Oyong oil. Cue Energy's share of production since the first gas was produced in February 2012 is summarised below:

Wortel – Production (Cue Energy Net Share)				
	Year ended 30 June			Six months ended
	2012 actual	2013 actual	2014 actual	31 Dec 2014 actual
Gas (MMscf)	930	2,152	1,867	867

Source: Cue Energy

The addition of compressors at the Grati gas plant, which is expected to be completed in the March 2015 quarter, will ensure that Wortel can continue to deliver the contracted gas volumes. The gas is sold at contracted prices (with some escalation) under a long term contract to a local power generator owned by PT Indonesia Power.

Indonesian Oil and Gas Fiscal Regime

Petroleum projects under the Indonesian PSC regime are subject to certain fiscal terms. The following apply to the Sampang PSC:

- First Tranche Petroleum: the Indonesian government receives 37.5% of the first 20% of gas produced and 64.3% of the first 20% of oil produced. The contractor retains the balance;
- Cost recovery: the contractor recovers operating costs and depreciation of capital expenditure from petroleum revenue;
- Domestic Market Obligation - Gas: the contractor's share of gas is sold on the domestic market at a price negotiated between the contractor and the customer;
- Domestic Market Obligation – Oil: the contractor's share of 25% of gross production is sold at a 15% discount to the market price. There are no restrictions in relation to the balance of the contractor's share of oil production;
- Profit share: the remaining petroleum after the deductions above is split between the Government of Indonesia and the contractor at the same rates as those applicable to the First Tranche Petroleum;
- the contractor's profits are taxed at the corporate tax rate of 44%; and

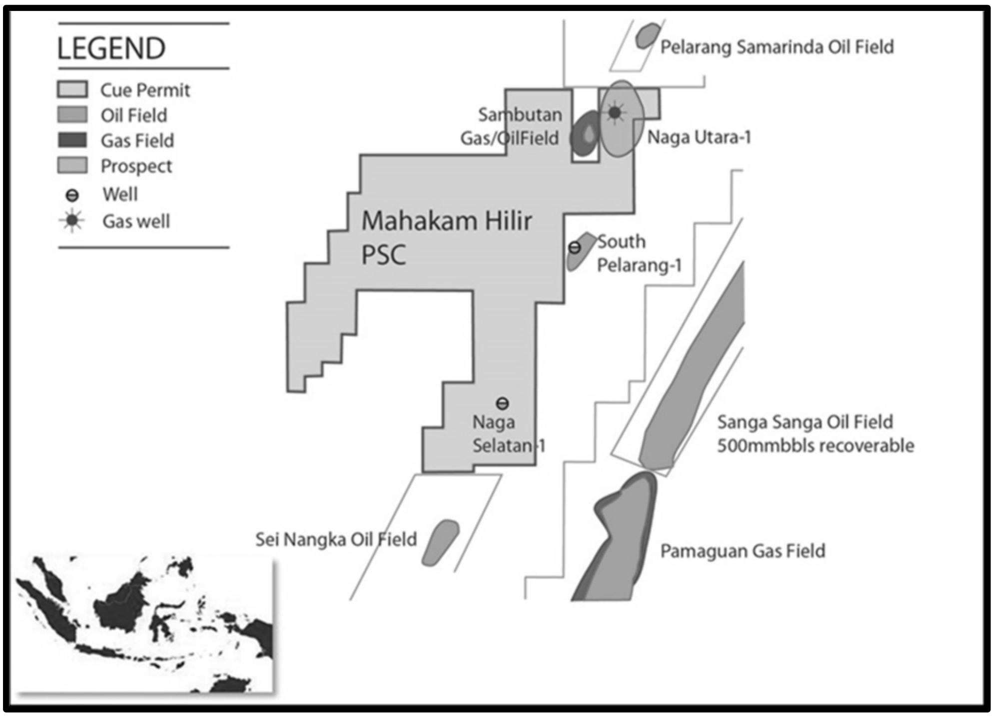
- no withholding taxes apply on cash repatriated to Australia.

Further, local Indonesian companies have a one off option to acquire up to 10% of a project prior to first production but are required to pay their pro-rata share of the costs incurred and to be incurred.

4.2.3 Exploration

Mahakam Hilir PSC (Indonesia, 100%)

Cue Energy has a 100% interest in the Mahakam Hilir PSC onshore East Kalimantan:



Source: Cue Energy

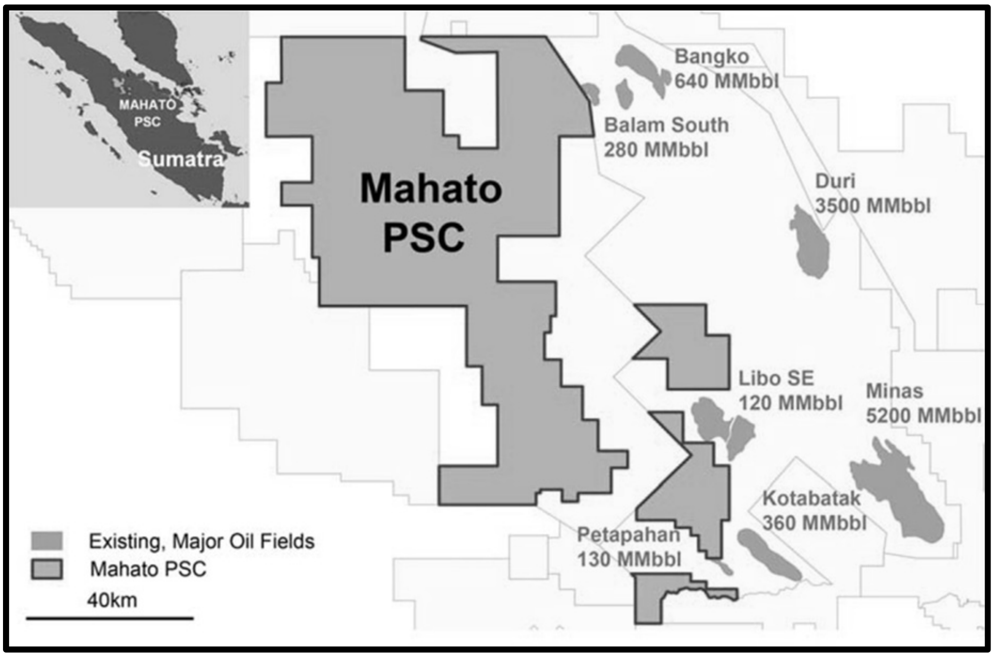
The company acquired its initial 40% stake in the PSC in 2011 and acquired the remaining 60% from the previous operator in October 2014[9]. The area is prospective for oil with several parallel geological trends hosting several large oil fields in the area. The previous operator drilled three wells in 2011 and 2012 (Naga-Utara 1 and 2 in the North and Naga Selatan 1 in the South) which did not yield significant results and decided to exit the area. Subsequent analysis by Cue Energy has identified a number of shallow prospects as well as a very large structure adjacent to the Naga Selatan-1 well, which Cue Energy is preparing to drill (Naga Selatan-2 well).

Mahato PSC (Indonesia, 12.5%)

Cue Energy acquired a 12.5% interest in the 5,600 km^2 Mahato PSC onshore Central Sumatra in Indonesia in November 2014[10]. The following map shows the location of the Mahato PSC and of the surrounding oil fields:

[9] The transaction has received Indonesian government approval and is subject only to completion.

[10] The transaction is still subject to Indonesian government approval.



Source: Cue Energy

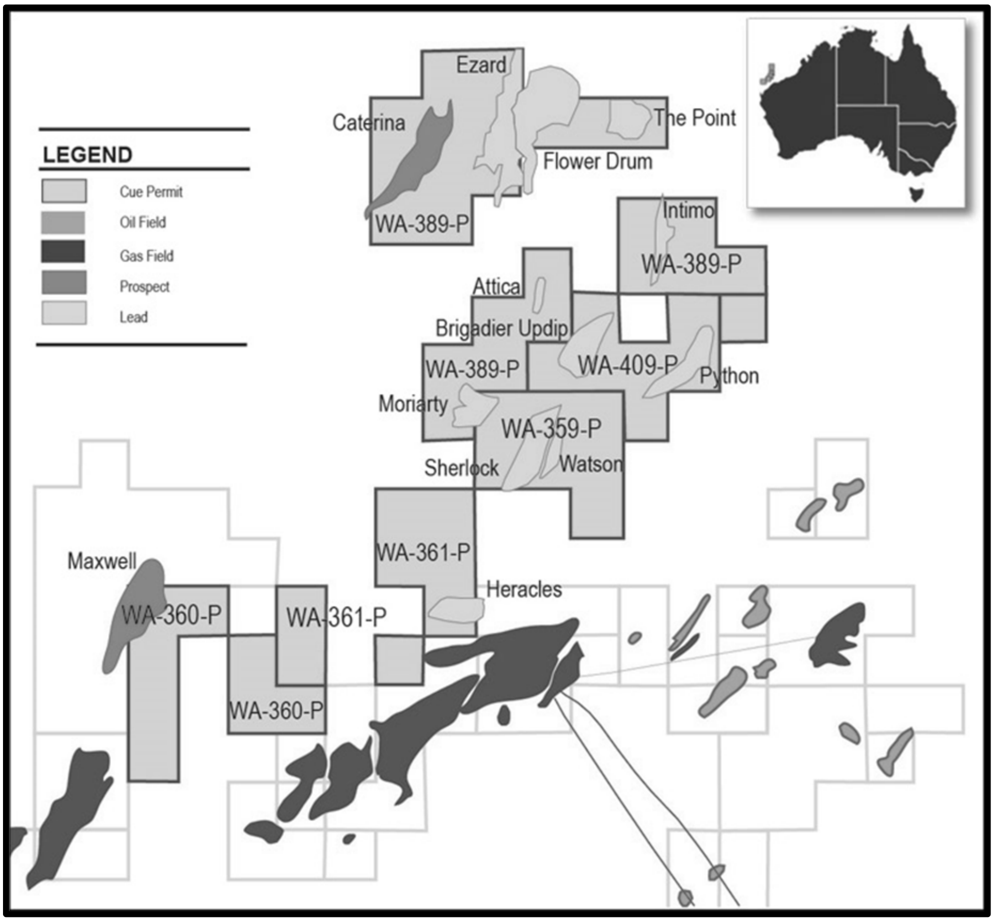
The area hosts a number of oil fields, including Indonesia's two largest oil fields, and has attracted interest from major oil and gas companies including Chevron Corporation. In 2015, the joint venture is planning to drill one appraisal well to test a possible extension of the Petapahan field into the Mahato PSC and an exploration well nearby. A 2D seismic programme is also planned to further define the large number of prospects. The existence of good local infrastructure will help with the commercialisation of any discoveries.

Jeruk (Indonesia, 8.182%)

The Jeruk PSC is located approximately 50 km west of the Sampang PSC. While a 2C contingent resource of 1.2mmbbl of oil (net to Cue Energy) has been delineated, the joint venture is currently not aligned on the future activities in the field due to substantial capital investment for appraisal, and expected lower quality of contained oil.

Carnarvon Basin (Australia, various interests)

Cue Energy holds interests in various licences located in the Carnarvon Basin offshore Western Australia as shown below:



Source: Cue Energy

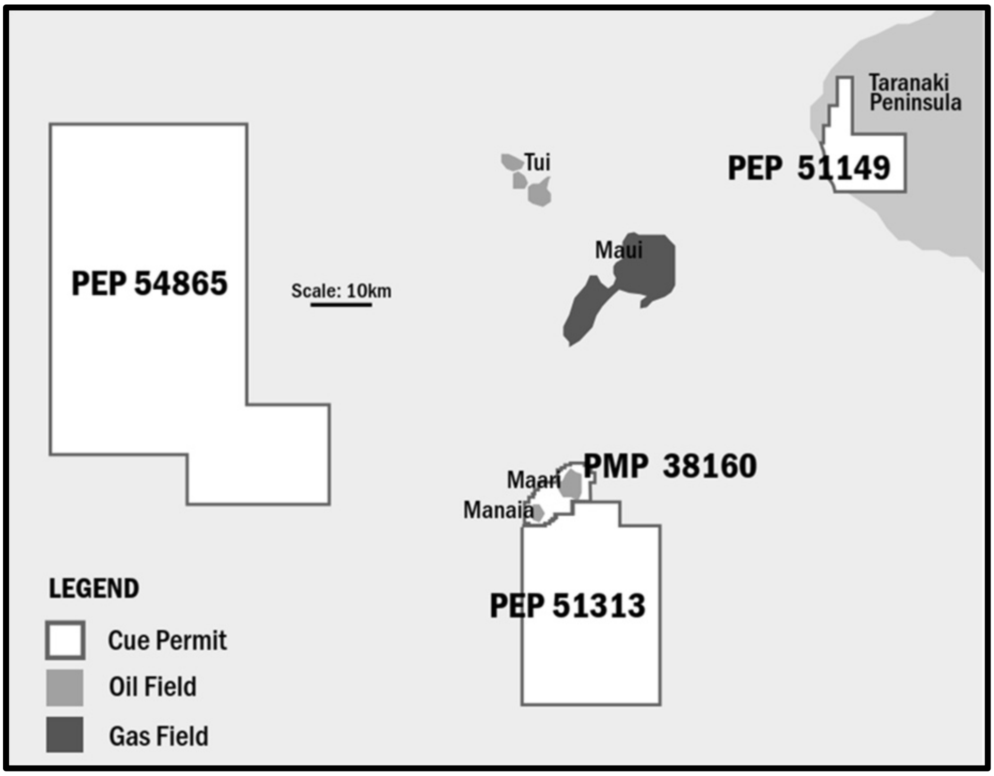
The company owns (100%) and operates licence WA-359-P. Cue Energy has assumed operatorship and has increased its interest from 30% to 100% in licence WA-409-P. Reprocessing of 3D seismic data over the WA-359-P permit has led to the upgrade of the Sherlock prospect and the estimate of oil in place has doubled to 300mmbbl. Cue Energy has also reprocessed 3D seismic data over the WA-409-P permit. The company believes that WA-359-P and WA-409-P have the potential to host a very large gas prospect and is currently completing technical analysis and mapping of the opportunity.

Cue Energy expects to commence marketing WA-359-P and WA-409-P within the next few months, with a view to soliciting farm-in or other proposals.

WA-389-P contains the Caterina prospect. This permit is currently undergoing seismic reprocessing by the operator, BHP Billiton. WA-360-P and WA-361-P are currently considered to be less prospective. The joint venturers are undertaking studies to further assess the potential of these permits.

Taranaki Basin (New Zealand, various interests)

Cue Energy has interests in one onshore exploration permit and two offshore exploration permits in the Taranaki Basin in New Zealand:



Source: Cue Energy

PEP 51149 (20%) hosts the Te Kiri prospect, which consists of both an oil target and a relatively small deeper gas target. The joint venture is currently developing a drilling plan with the aim to drill a commitment well by the end of 2015.

PEP 51313 (14%) is considered not as prospective and has modest work commitments. The Whio-1 exploration well, drilled seven kilometres south of the Maari field in July 2014, was dry. In 2014, the joint venture opted to forgo the drilling of a commitment well and has relinquished the western part of the permit.

PEP 54865 (20%) is also a low priority target.

4.3 Financial Performance

The financial performance of Cue Energy for the three years ended 30 June 2014 and the six months ended 31 December 2014 is summarised below:

Cue Energy - Financial Performance ($ 000s)				
	Year ended 30 June			Six months to 31 December
	2012 actual	2013 actual	2014 actual	2014 actual
Revenue	**41,222**	**49,798**	**34,005**	**18,641**
EBITDA[11]	**21,201**	**22,109**	**9,200**	**8,269**
Depreciation and amortisation	(10,544)	(17,559)	(9,362)	(5,068)
EBIT[12]	**10,657**	**4,550**	**(162)**	**3,201**
Interest income/(expense)	190	157	162	58
Significant and non-recurring items	-	-	(3)	5,830
Net realised gain on oil hedge derivatives	158	-	-	
Net foreign currency exchange gain	2,616	3,702	81	5,022
Operating profit before tax	**13,621**	**8,409**	**78**	**14,111**
Income tax expense	(7,958)	(2,040)	(2,244)	(358)
NPAT[13]	**5,663**	**6,369**	**(2,166)**	**13,753**
Statistics				
Basic earnings per share	*0.81*	*0.91*	*(0.31)*	*1.97*
Sales revenue growth	-	*21%*	*-32%*	-
EBITDA growth	-	*4%*	*-58%*	-
EBIT growth	-	*-57%*	*-104%*	-
EBITDA margin	*77%*	*72%*	*58%*	*69%*
EBIT margin	*39%*	*15%*	*-1%*	*27%*

Source: Cue Energy and Grant Samuel analysis

The contribution of Cue Energy's business segments to the company's revenue and gross profit is as follows:

11 EBITDA is earnings before net interest, tax, depreciation and amortisation and significant and non-recurring items.

12 EBIT is earnings before net interest, tax and significant and non-recurring items.

13 NPAT is net profit after tax attributable to Cue Energy shareholders.

Cue Energy - Financial Performance ($ 000s)[14]				
	Year ended 30 June			Six months to 31 December
	2012 actual	2013 actual	2014 actual	2014 actual
Production (mboe)				
Maari	270	179	83	64
Sampang PSC	525	747	547	237
South East Gobe	29	21	14	7
Total production	**824**	**947**	**644**	**308**
Sales revenue				
New Zealand	21,874	19,590	10,156	7,486
Indonesia	16,106	27,926	22,090	10,410
Papua New Guinea	3,242	2,282	1,759	745
Total sales revenue	**41,222**	**49,798**	**34,005**	**18,641**
Gross profit from production				
New Zealand	15,789	11,140	4,468	n.a.
Indonesia	9,337	18,725	11,810	n.a.
Papua New Guinea	2,318	802	(486)	n.a.
Total gross profit from production	**27,444**	**30,667**	**15,792**	n.a.
Other (expenses)/income (net)[15]	(6,243)	(8,558)	(6,592)	n.a.
EBITDA (as above)	**21,201**	**22,109**	**9,200**	n.a.

Source: Cue Energy and Grant Samuel analysis

Cue Energy's financial performance has fluctuated over the past three years, largely driven by movements in the company's share of production.

In FY13, Cue Energy's revenue grew significantly as a result of an increase in gas production from the Sampang PSC, reflecting the first full year of production at the Wortel field and an increase in production at the Oyong field. This was partially offset by higher amortisation charges relating to the Sampang PSC.

Sales revenue and earnings fell sharply in FY14 as a result of the interruption of production at Maari and natural field decline at Oyong. FY14 earnings were also affected by the cost of repairs at the Maari production facility.

The significant increase in net profit after tax in the second half of 2014 was due to the increase in production at Maari, foreign exchange movements and significant items relating to the sale of its asset portfolio in Papua New Guinea.

Outlook

Cue Energy has not publicly released earnings forecasts for FY15 or beyond. However, at its annual general meeting on 27 November 2014, Cue Energy announced that it expected production to increase by 23% in FY15 to 0.80 million boe. For the calendar year 2016 and beyond, reduced production is expected due to natural field decline. Cue Energy has announced that it proposes to mitigate expected production decline by acquiring existing production or projects at the stage of near term development to supplement any exploration success.

14 As a large proportion of exploration expenditure is capitalised, the revenue and gross profit of Cue Energy's business segments (New Zealand, Indonesia and Papua New Guinea) mostly reflect the performance of the producing assets within those segments.

15 Other expenses include employee, superannuation, administrative, operating lease and business development expenses.

4.4 Financial Position

The financial position of Cue Energy as at 30 June 2014 and 31 December 2014 is summarised below:

Cue Energy - Financial Position ($ 000s)		
	As at 30 June 2014 actual	**As at 31 December 2014 actual**
Receivables	3,542	4,282
Inventories	843	865
Payables and provisions	(21,747)	(10,964)
Net working capital	**(17,362)**	**(5,817)**
Production properties	79,458	83,103
Exploration and evaluation expenditure	54,069	55,477
Property, plant and equipment	118	82
Non-current provisions	(5,627)	(4,553)
Current tax assets / (liabilities) (net)	(2,398)	(4,802)
Deferred tax assets / (liabilities) (net)	(19,413)	(17,437)
Total funds employed	**88,845**	**106,053**
Cash and deposits	40,558	37,103
Net assets attributable to Cue Energy shareholders	**129,403**	**143,156**
Statistics		
Shares on issue at period end (000s)	*698,120*	*698,120*
Net assets per share	*0.19*	*0.21*

Source: Cue Energy and Grant Samuel analysis

Cue Energy's balance sheet reflects its exploration and production activities and a strong financial position.

The payables amount includes a contingent liability of US$4.5 million pursuant to arrangements relating to the Jeruk field. Cue Energy believes that this is the maximum amount that would be payable, although this is in dispute. An arbitration hearing has found in favour of Cue Energy but the matter remains to be settled. Cue Energy expects settlement shortly.

Insurance claims have been lodged in relation to the failure of the swivel and mooring system at Maari. An expert has been engaged and recommended that the underwriters pay a total of $66 million to the joint venture partners, although the ultimate quantum and timing of the payment remain uncertain. The joint venture partners have already received $5 million.

At 30 June 2014, Cue Energy disclosed production development expenditure capital commitments of approximately $20.6 million ($15.4 million within 12 months) and discretionary exploration expenditure capital commitments of approximately $38.9 million ($9.5 million within 12 months). These commitments have not been brought to account.

Cue Energy had no debt and a cash balance of approximately $37.1 million as at 31 December 2014 which is held mostly in United States dollars.

Cue Energy receives proceeds from the sale of oil and gas in US dollars and incurs the majority of its exploration and appraisal costs in US dollars. The company holds a large proportion of its cash holdings in US dollars to manage its exposure to movements in the USD:AUD exchange rate. The company is also exposed to movements in commodity prices and may use swap and option contracts to manage this risk. As at 26 February 2015, the company did not have any hedging in place.

Under the Australian tax consolidation regime, Cue Energy and its wholly owned Australian resident entities have elected to be taxed as a single entity. Cue Energy has significant Australian carried forward income tax losses (approximately $52.2 million at 30 June 2014). However, the company does not expect to be able to utilise these tax losses at this stage.

Profits from the New Zealand and Indonesian operations are taxed locally at the relevant tax rates. At 31 December 2014, Cue Energy had no carried forward tax losses in Indonesia and NZ$12.9 million of carried forward tax losses in New Zealand.

4.5 Cash Flow

Cue Energy's cash flows for the three years ended 30 June 2014 and the six months ended 31 December 2014 are summarised below:

Cue Energy - Cash Flow ($ 000s)

	Year ended 30 June			Six months to 31 December
	2012 actual	2013 actual	2014 actual	2014 actual
EBITDA (as reported)	**24,249**	**25,971**	**9,440**	19,179
Changes in working capital and other adjustments	(4,477)	6,856	2,311	(13,416)
Capital expenditure (net)	(35,401)	(10,855)	(23,856)	(22,839)
Operating cash flow	**(15,629)**	**21,972**	**(12,105)**	**(17,076)**
Tax paid	(8,257)	(244)	(6,298)	
Net interest received/(paid)	214	146	167	63
Disposals/(Acquisitions) (net of cash)	7,407	-	-	8,536
Proceeds from share issues	648	-	-	
Proceeds/(Repayments) from borrowings	(5,086)	-	-	
Net cash generated (used)	**(20,703)**	**21,874**	**(18,236)**	**(8,477)**
Net cash (borrowings) – opening	*52,811*	*33,733*	*58,828*	*40,558*
Effect of exchange rate change	*1,625*	*3,221*	*(34)*	*5,022*
Net cash (borrowings) – closing	*33,733*	*58,828*	*40,558*	*37,103*

Source: Cue Energy and Grant Samuel analysis

Cue Energy's cash flows over the period have fluctuated significantly, reflecting variations in the production volumes and profitability of its operating assets and movements in capital expenditure and other capital investments.

In FY12, strong operating earnings and the proceeds from the sale of its 20% interest in the Cash-Maple gas field in the Timor Sea were offset by investments in working capital, exploration, and capital expenditure including in relation to the development of the Wortel field. The result was a net cash outflow for the year of $20.7 million.

Cue Energy generated strong positive cash flows in FY13, reflecting continued strong operating performance, reductions in working capital and sharply reduced exploration and capital expenditure. Operating cash flows for FY14 fell substantially, reflecting the suspension of Maari production for 145 days and natural production decline at Wortel and Oyong. Together with increased exploration and production expenditure and significant tax payments, this resulted in a net cash outflow for the year of $18.2 million.

Cue Energy received $8.5 million for the sale of its PNG assets, although this was offset by investments in capital expenditure resulting in a net cash outflow of $8.5 million for the half year ended 31 December 2014.

4.6 Capital Structure and Ownership

At 26 February 2015, Cue Energy had 698,119,720 ordinary shares on issue. At 30 September 2014 there were 4,947 registered shareholders in Cue Energy. Around 47% of registered shareholders hold less than 10,000 shares and 1,246 shareholders hold less than a marketable parcel[16]. Directors and executives of Cue Energy account for less than 1% of the shares on issue. Cue Energy has received substantial shareholder notices as follows:

Cue Energy – Substantial Shareholders

Shareholder	Date of Notice	Number of Shares	Percentage[17]
NZOG Offshore[18]	n.a.	139,554,132	20.11%
Singapore Petroleum Company Limited	24 July 2009	112,996,671	16.19%
Zeta Energy Pte. Ltd	19 December 2014	88,644,161	12.70%
The Todd Corporation Limited	24 December 2014	49,469,182	7.09%

Source: Cue Energy

On 22 December 2014, NZOG announced that, together with its associates, it had acquired a relevant interest in 19.99% of Cue Energy's shares from The Todd Corporation Limited. Since the announcement of the Offer, NZOG has increased its relevant interest in Cue Energy shares to 20.11%.

4.7 Share Price Performance

4.7.1 Share Price Performance

Cue Energy shares commenced trading on the ASX in December 1995 below the $0.20 subscription price and, apart for much of 1997, over the period to late 2004 generally traded well below that level. The share price followed the stock market higher from 2005 (to around $0.35) but experienced significant volatility during the global financial crisis and its aftermath and then in the subsequent period of improved equity market conditions. Cue Energy shares closed at $0.23 on 31 December 2009.

A summary of the price and trading history of Cue Energy since 1 January 2010 is set out below:

16 Under ASX Listing Rules, a marketable parcel is a parcel of securities of not less than $500.

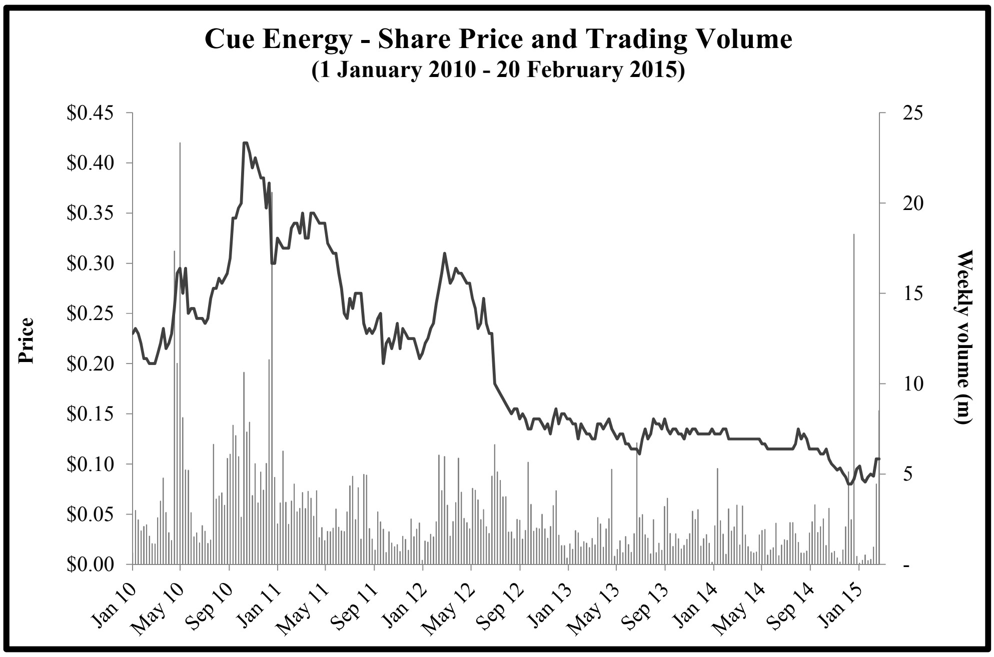
17 Calculated as a percentage of the number of Cue Energy shares on issue at 26 February 2015, being 698,119,720.

18 Sourced from Cue Energy's share register as at 26 February 2015.

Cue Energy - Share Price History					
	Share Price (cents)			Average Weekly Volume (000's)	Average Weekly Transactions
	High	Low	Close		
Year ended 31 December					
2010	45.0	19.0	32.5	5,103	275
2011	36.0	19.0	21.0	2,505	173
2012	32.0	12.5	14.0	2,868	166
2013	15.0	10.5	13.5	1,703	60
Quarter ended					
31 March 2014	13.5	12.5	13.0	2,253	57
30 June 2014	13.0	11.0	11.5	1,203	32
30 September 2014	13.5	11.0	11.0	1,676	34
31 December 2014	11.5	7.4	9.8	2,869	32
Month ended					
31 January 2015	9.9	7.8	9.0	281	16

Source: IRESS

The following graph illustrates the movement in the Cue Energy share price and trading volumes since 1 January 2010:



Source: IRESS

After declining further to around $0.20 in February 2010, the Cue Energy share price steadily recovered reaching an all-time high of $0.45 on 11 October 2010 on the back of record financial performance in FY10. Around the time of the resignation of long term chief executive officer Bob Coppin in late 2010, the Cue Energy share price dropped sharply to around $0.30. The share price recovered somewhat in the first half of 2011, with shares trading in the range of $0.30 to $0.35. However, for the remainder of 2011, Cue Energy shares traded broadly below $0.25 and closed at $0.195 on 4 October 2011.

On the back of encouraging drilling results at Mahakam Hilir permit and an increase in global oil prices, the Cue Energy share price increased again in February 2012 to around

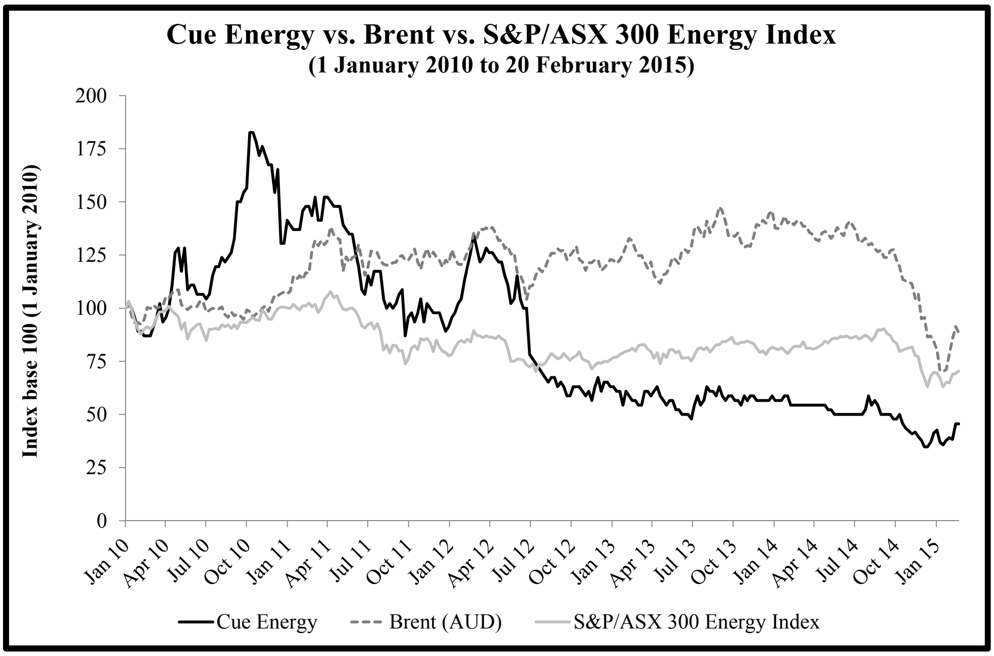
$0.30 until June 2012 when, following the announcement that the Banambu Deep-1 exploration well in Western Australia was a dry hole, it fell back below $0.20. Subsequently, Cue Energy shares have gradually declined to trade below $0.10 in late 2014 in line with the rapid decline in oil prices.

Following the announcement of the share acquisition by NZOG late last year, the share price jumped from $0.085 on 19 December 2014 to $0.095 on 22 December 2014. Since then the share price has traded in the range of $0.078 to $0.099 and closed at $0.09 on 11 February 2015 (the last day Cue Energy shares traded prior to the announcement of the Offer).

After the announcement of the Offer, Cue Energy shares have generally traded above the Offer price of $0.10.

Cue Energy is not a liquid stock. It has a tightly held register with around 56% of its shares on issue held by the four substantial shareholders. Accordingly, Cue Energy's free float has been limited and its shares have been relatively illiquid. Average weekly volume over the twelve months prior to the announcement of the Offer represented approximately 0.25% of average shares on issue which corresponds to an annual turnover of around 13% of the share register.

The following graph illustrates the relative performance of Cue Energy shares since 1 January 2010 relative to the Brent oil price expressed in Australian dollars and the S&P/ASX 300 Energy Index:



Source: IRESS

Cue Energy outperformed the Brent oil price and the S&P/ASX 300 Energy Index, until the second half of 2011 and 2012 respectively. Since then, Cue Energy shares have generally mirrored movements in the index and the Brent oil price but have displayed greater volatility and, overall, have substantially underperformed. However, following recent falls in the oil price, the differential between the Brent oil price and the Cue Energy share price has narrowed considerably.

5 Valuation of Cue Energy

5.1 Summary

Grant Samuel has valued Cue Energy in the range $82-106 million which corresponds to a value of 11.7-15.2 cents per share. The valuation represents the estimated full underlying value of Cue Energy assuming 100% of the company was available to be acquired and includes a premium for control. The value exceeds the price at which, based on current market conditions, Grant Samuel would expect Cue Energy shares to trade on the ASX in the absence of a takeover offer.

The valuation of Cue Energy is the aggregate of the estimated market value of Cue Energy's oil and gas interests and its net cash, adjusted for its non-trading assets and liabilities. The valuation is summarised below:

Cue Energy - Valuation Summary ($ millions)

	Report Section Reference	Value Range (US$m)		Value Range ($m)	
		Low	High	Low	High
Maari	5.4.1	19	24	24	30
Sampang	5.4.2	12	16	15	20
Exploration	5.4.3			10	20
Other assets and liabilities	5.5			(2)	(1)
Head office costs (net of savings)	5.6			(4)	(2)
Enterprise value				**43**	**67**
Net cash at 31 December 2014	5.7			39	39
Value of equity				**82**	**106**
Fully diluted shares on issue (millions)				698.1	698.1
Value per share (cents)				**11.7**	**15.2**

The principal approach to valuing Cue Energy's producing assets was by discounted cash flow analysis. Valuation scenarios were developed by Grant Samuel for Cue Energy's Maari and Sampang assets on the basis of assumptions regarding production rates, operating costs and capital costs developed by the independent technical specialist RISC. RISC's operating assumptions are summarised below and set out in detail in RISC's report in Appendix 3.

Grant Samuel's valuation models use as their starting point the balance sheet of Cue Energy as at 31 December 2014 and project US$ denominated cash flows from 1 January 2015 onwards. Projected ungeared after tax cash flows were discounted to a present value using a nominal after tax discount rate of 9.5-10.5%. Appendix 1 sets out a detailed analysis of the selection of this discount rate. Estimated US$ values were converted to A$ equivalents at the spot exchange rate of A$1.00 = US$0.79.

The valuation should be considered in the context of the following:

- judgements about future oil prices are inherently uncertain, given the recent volatility in oil prices. While Grant Samuel has assumed long term prices for Brent oil in the range of US$75-85/bbl for the purposes of the valuation, a broad range of assumptions could reasonably be adopted;

- a significant proportion of the value attributed to Cue Energy relates to its interest in the Maari field. The Maari Growth Project currently underway consists of a number of initiatives aimed at lifting production and extending field life. However, progress to date has been below expectations with cost overruns, delays and disappointing well performance. The Maari joint venturers are in the process of considering alternatives to address these issues. Given the status of the Growth Project, there is considerable uncertainty as to the ultimate outcomes for the field. RISC has recommended valuation scenarios that contemplate a range of production and cost outcomes. However, the actual oil recoveries and cost outcomes could be very different from those modelled;

- while only modest value has been attributed to Cue Energy's exploration assets, Cue Energy is budgeting significant exploration expenditures for the short to medium term. The funding of this expenditure will require a significant proportion of Cue Energy's cash resources. The value consequences of the exploration program could fall within a very wide range. In some cases, the outcomes are essentially binary, with the potential for exploration drilling to prove up material value but also the risk that drilled exploration targets prove to have zero value. Accordingly, the ultimate value of Cue's exploration interests (including, effectively, the cash holdings required to fund its exploration program) could be significantly greater than – but could also be far less than – current estimates of value; and
- overall, given these factors, the value of Cue Energy could shift, potentially materially, over the short to medium term. Depending on field development and exploration success the value of Cue Energy could potentially exceed Grant Samuel's valuation range by a significant margin. However, there is also the potential for the value of Cue Energy to be materially lower than Grant Samuel's current estimates of value.

The value range of $82-106 million implies the following valuation parameters:

Cue Energy – Implied Valuation Parameters ($/mmboe)			
	Variable	Implied Multiple	
		Low	High
Enterprise Value range ($ million)		**43**	**67**
2P reserves - as at 31 December 2013 (mboe)	3,849	11.4	17.4
2P + 2C - as at 31 December 2013 (mboe)	5,092	8.4	13.2
Production - year ended 30 June 2014 (mboe)	630	68	106
EBITDA - year ended 30 June 2014 (A$ millions)	9.2	4.7	7.3

The multiples of reserves, resources and production implied by the valuation are broadly consistent with the market evidence from comparable companies (see Appendix 2). However, it should be recognised that, given the wide variations in such factors as asset life, production rate, operating cost, capital costs, reserves potential and exploration upside, valuation evidence based on reserve, resource and production benchmarks provides in this context only very general guidance as to value. The historical EBITDA multiples implied by the valuation of Cue Energy are relatively high compared to those for the comparable companies. This reflects the reduction in Cue Energy's earnings for the year to 30 June 2014 resulting from the interruption in Maari production between July and December 2013.

5.2 Methodology

Grant Samuel's valuation of Cue Energy has been estimated by aggregating the estimated market value of its operating business (on a "control" basis) together with the realisable value of non-trading assets and deducting external borrowings and non-trading liabilities. The value of the operating business has been estimated on the basis of fair market value as a going concern, defined as the maximum price that could be realised in an open market over a reasonable period of time assuming that potential buyers have full information.

The most reliable evidence as to the value of a business is the price at which the business or a comparable business has been bought and sold in an arm's length transaction. In the absence of direct market evidence of value, estimates of value are made using methodologies that infer value from other available evidence. There are four primary valuation methodologies that are commonly used for valuing businesses:

- capitalisation of earnings or cash flows;
- discounting of projected cash flows;

- industry rules of thumb; and
- estimation of the aggregate proceeds from an orderly realisation of assets.

Each of these valuation methodologies has application in different circumstances. The primary criterion for determining which methodology is appropriate is the actual practice adopted by purchasers of the type of business involved.

Grant Samuel's primary approach to the valuation of Cue Energy's producing oil and gas assets has involved the application of the DCF methodology. The discounted cash flow methodology involves the calculation of net present values by discounting expected future cash flows. Projected cash flows are discounted to a present value using discount rates that take into account the time value of money and risks associated with the cash flows. The discounted cash flow methodology is particularly appropriate for assets such as oil and gas projects where reserves are depleted over time and significant capital expenditure is required. By contrast, capitalisation of earnings or cash flows is the most commonly used method for valuation of industrial businesses. This methodology is most appropriate for industrial businesses with a substantial operating history and a consistent earnings trend that is sufficiently stable to be indicative of ongoing earnings potential. This methodology is not particularly suitable for start-up businesses, businesses with an erratic earnings pattern or businesses that have unusual capital expenditure requirements. This methodology is in particular not suitable for the valuation of Aurora's business operations which have high upfront capital expenditure requirements and substantial variations in cash flows and earnings in the early years.

Grant Samuel developed a cash flow model for Cue Energy's Maari and Sampang interests on the basis of operating scenarios developed by RISC, which were based on production plans provided by Cue Energy. RISC reviewed each of the technical assumptions in Cue Energy's operating models, including those regarding reserve estimates, production profiles, operating costs, capital costs and the potential for reserve extensions, and made adjustments to these assumptions when appropriate. Grant Samuel determined the economic and financial assumptions used in the cash flow models. The net present value of the Maari and Sampang interests has been calculated on an ungeared after tax basis as at 1 January 2015.

Alternative valuation methodologies have been considered as secondary evidence of value as to the value of Cue Energy's producing interests. In particular, the estimates of value have been reviewed to the extent possible and appropriate in terms of multiples of oil and gas reserves, which are metrics commonly used to assess values in the oil and gas sectors. The valuation metrics, while relatively crude, are useful in assessing the reasonableness of a discounted cash flow valuation since the discounted cash flow valuation is typically sensitive to the assumptions adopted.

The valuation of the Maari and Sampang interests represents Grant Samuel's overall judgement as to value. It does not rely on any one particular scenario or set of economic assumptions. The valuation has been determined having regard to the sensitivity of the DCF analysis to a range of technical and economic assumptions. It incorporates Grant Samuel's judgemental assessment of the impact on value of development status and optionality, to the extent not reflected in the DCF analysis.

The valuation is based on a number of important assumptions, in particular assumptions regarding future oil and gas prices, and reflects the technical judgements of RISC regarding the prospects for Cue Energy's Maari and Sampang operations. Oil prices and expectations regarding future operating parameters can change significantly over short periods of time. Such changes can have significant impacts on underlying value. Accordingly, while the values estimated are believed to be appropriate for the purpose of assessing the Offer, they may not be appropriate for other purposes or in the context of changed economic circumstances or different operational prospects for the oil and gas assets of Cue Energy.

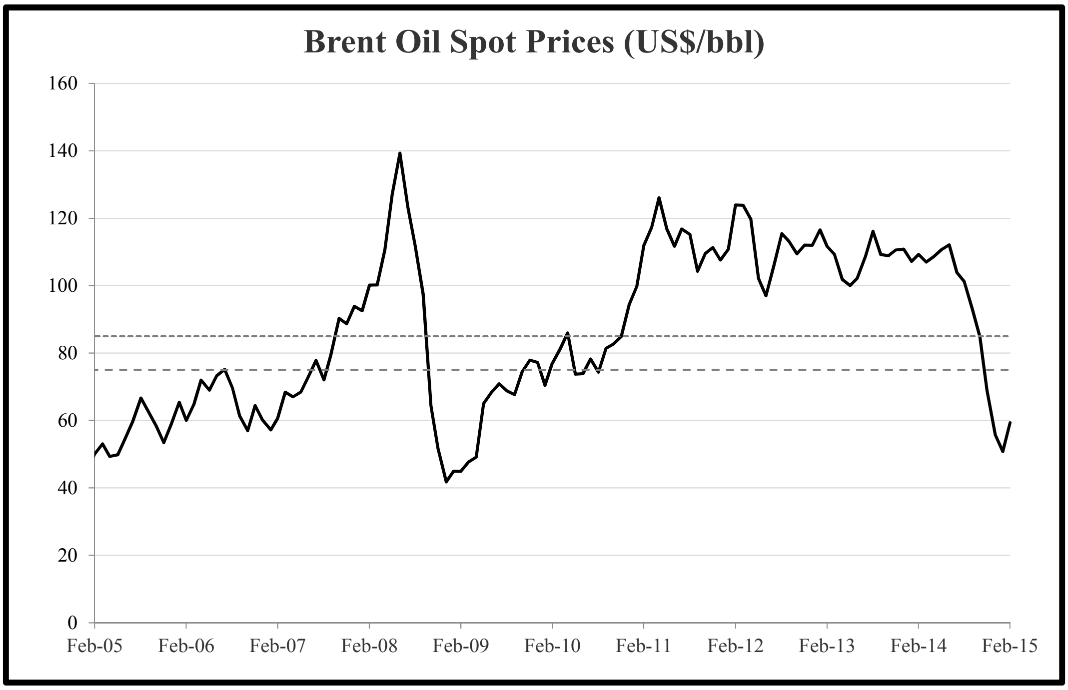
5.3 Valuation Assumptions

The valuation of Cue Energy's Maari and Sampang interests has been determined by reference to DCF valuation analysis. This analysis involves making a number of general assumptions regarding future oil and gas prices, economic factors and discount rates. The DCF analysis results in the calculation of estimated net present value ("NPV") under a range of assumptions. The calculated NPVs are sensitive to the assumptions used in the analysis and relatively small changes in certain variables can cause significant changes in value. For this reason, DCF valuations should be treated with caution.

The key assumptions are:

- Brent crude oil prices increasing from the prevailing spot to a range of US$75-85 per barrel from 2018 and flat thereafter;
- realised oil price at a US$4.00/bbl premium to Brent for the Maari assets and at a US$1.00/bbl discount to Brent for Oyong;
- natural gas prices as per Oyong and Wortel contract prices;
- US inflation rates of 2.5% per annum;
- tax depreciation schedules determined on the basis of tax written down values of the assets;
- carry forward New Zealand tax losses as at 31 December 2014 of NZ$12.9 million; and
- nominal discount rates for the discounted cash flow valuations in the range 9.5-10.5%. The discount rates represent estimates of the costs of capital for investors in oil and gas projects based on analysis using the capital asset pricing model. The rates are estimates of weighted average costs of capital and have been applied to expected future ungeared after tax cash flows. The basis for the selection of the rates is set out in Appendix 1.

The valuation was based on current oil prices and expectations of future oil prices prevailing in mid-February 2015. Grant Samuel has assumed that Brent crude prices (in real terms) will increase from current levels to a long term price range of US$75-85 per barrel by 2018. The Brent price assumptions compared to historical Brent prices are shown below:



Source: Bloomberg
Note: Historical prices are in nominal terms whereas Grant Samuel price assumptions are in 2015 dollars.

The Brent crude price assumptions adopted for the purposes of the valuation of Cue Energy's producing assets are broadly consistent with the range of forecast price assumptions used by market analysts. However, assumptions regarding future oil prices are subject to considerable uncertainty:

- the Brent oil price has recently been extremely volatile. The Brent oil price fell from US$115.00/bbl on 19 June 2014 to a six-year low of US$45.25/bbl on 26 January 2015. It then rose to US$61.23/bbl on 17 February 2015, a gain of 35% over a three week period. It closed at US$61.46/bbl on 26 February 2015, approximately 47% lower than the price of eight months earlier;
- in the context of extreme oil price volatility, price forecasts by analysts and industry commentators may become rapidly out of date and so "consensus" price forecasts may lag current market expectations;
- although the majority of forecasts of Brent oil prices by industry analysts, commentators and corporate participants fall within a relatively narrow range of US$75-85 per barrel (from 2018, real terms), there are some market participants who are forecasting much lower or much higher prices; and
- the ICE Brent Futures Contract curve in mid-February 2015 slopes up to approximately US$80 per barrel by June 2021, which corresponds to approximately US$70 per barrel in real terms. Although prices of futures contracts are not necessarily directly correlated to forecast spot prices, they are used by some market participants for their investment decisions.

The value of Cue Energy's producing interests could vary significantly with changes in oil price expectations. The assumptions in relation to future oil prices adopted by Grant Samuel do not represent forecasts by Grant Samuel but are intended to reflect the range of assumptions that could reasonably be adopted by industry participants in their pricing of Cue Energy and its assets.

5.4 Valuation of Cue Energy's Oil and Gas Assets

5.4.1 Maari

Grant Samuel has valued Cue Energy's 5% interest in the Maari field in the range US$19-24 million.

Grant Samuel's valuation of Maari had regard to three life of field scenarios recommended by RISC. Each of the scenarios is based on production from existing wells and a common set of development activities (including the drilling of additional wells and water re-injection) pursuant to the Maari Growth Project. RISC has considered whether there would be an opportunity to improve field performance through the drilling of further wells (i.e. in addition to those already approved by the joint venture, as reflected in the three scenarios). However, RISC's indicative analysis suggests that these additional wells would be unlikely to be economic. Accordingly, the differences between the scenarios relate to varying assumptions regards reservoir performance and the extent to which the proposed water injection initiatives deliver the expected benefits.

The two principal scenarios for valuation purposes both reflect RISC's best estimate of reservoir performance, but make varying assumptions regarding the benefits to be realised from the water injection program. These scenarios are referred to in the analysis below as Scenarios 1 and 2. RISC has also recommended that consideration be given to a third scenario ("Downside Scenario"), developed to show the impact on net present values of poor reservoir performance combined with a failure of the water injection program to deliver the benefits expected, although this should be viewed as a low probability outcome.

The scenarios are summarised as follows:

- **Scenario 1** is based on RISC's best estimate of reservoir performance and factors in significant benefits from the water injection scheme. Oil produced over the remaining life of the operation is 40.9mmbbl. Capital expenditure over the life of the field totals US$362 million. This primarily consists of US$103 million in 2015, principally relating to remedial work and completion of the MR6A well, the sidetracking of the MR7A well and the drilling of the MR10 well as per the Growth Project, US$43.8 million for the repair of a mooring line in 2016 to 2018 and US$50 million to refurbish the wellhead platform and the FPSO in 2029. Operating costs of US$70-90 million per annum are assumed. These costs are largely fixed in nature and include approximately US$33 million per year for operation of the platform. Abandonment costs of US$198 million are assumed to be incurred at the end of the life of the field;

- **Scenario 2** is essentially identical to Scenario 1, except that it assumes no benefit from the water injection programme. Production over the remaining life of the field is reduced to 35.1mmbbl. There are no changes to operating, capital and abandonment costs; and
- The **Downside scenario** assumes both poor reservoir performance and no benefit from the water injection programme. Total oil produced over the remaining life of the field is 23.6mmbbl. Capital costs are US$2 million lower than in Scenarios 1 and 2 as the conversion of a well from a producer to an injector is assumed not to proceed because of the disappointing results from water injection. Operating and abandonment cost assumptions are the same as for Scenarios 1 and 2.

The following table summarises projected production and costs for the three scenarios:

Maari – Model Parameters (100%)

	Year ended 31 December						2021-	
	2015	2016	2017	2018	2019	2020	2040	Total
Scenario 1								
Oil (mmbbl)	4.1	5.0	4.0	3.4	2.8	2.4	19.2	**40.9**
Capex (US$m)	135	20	14	46	8	8	131	**362**
Opex (US$m)	82	84	83	89	90	87	1,389	**1,904**
Scenario 2								
Oil (mmbbl)	4.1	5.0	3.7	2.9	2.4	2.0	15.0	**35.1**
Capex (US$m)	135	20	14	46	8	8	131	**362**
Opex (US$m)	82	84	83	89	90	87	1,389	**1,904**
Downside Scenario								
Oil (mmbbl)	3.9	4.3	2.9	2.1	1.6	1.3	7.5	**23.6**
Capex (US$m)	135	20	14	46	8	8	131	**362**
Opex (US$m)	82	84	83	89	90	87	1,389	**1,904**

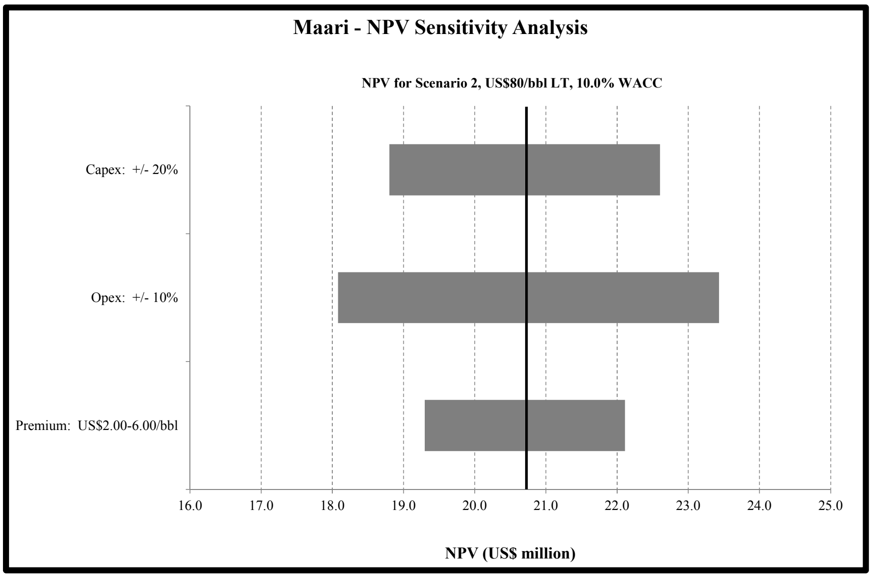
Grant Samuel has calculated net present values for the three scenarios for a range of assumptions regarding future oil prices and discount rates. The following table summarises the results of the NPV analysis for Maari for the three scenarios:

Maari (Cue Energy Share) – NPV Analysis (US$ million)				
	Discount Rate	Brent Oil Price Scenario		
		US$75/bbl	US$80/bbl	US$85/bbl
Scenario 1				
	9.5%	24.5	27.3	30.0
	10.0%	24.7	27.5	30.3
	10.5%	24.8	27.7	30.6
Scenario 2				
	9.5%	18.3	20.7	22.9
	10.0%	18.4	20.7	23.0
	10.5%	18.4	20.7	23.1
Downside Scenario				
	9.5%	4.1	5.6	7.2
	10.0%	3.9	5.5	7.1
	10.5%	3.8	5.4	7.0

The NPV analysis takes into account the written down tax value of assets as at 31 December 2014.

The value of US$19-24 million attributed by Grant Samuel to Cue Energy's 5% interest in Maari takes into account the analysis set out above as well as the following factors:

- Scenarios 1 and 2 are based on RISC's best estimate of future reservoir performance. Present values calculated for these scenarios should be given most weight in assessing the value of Maari. However, given the recent disappointing performance of the Maari field, potential acquirers of the asset would be likely to have some regard to the potential for ongoing field underperformance. The Downside Scenario is essentially a representation (albeit arguably an extreme case) of such underperformance;
- the effectiveness of the planned water injection programme in terms of improving oil recoveries remains highly uncertain. Water injection has not delivered the expected benefits to date, in particular in the Lower Moki reservoir;
- the Growth Project has experienced delays, cost overruns and well performance issues. The joint venture participants are continuing to review the activity plan for the Maari field in light of the recent field performance. In this context, there is significant uncertainty in terms of ultimate costs and future production performance. This uncertainty is addressed in part through the range of outcomes modelled in the valuation scenarios. In addition, Grant Samuel has assessed the sensitivity of calculated NPVs for Scenario 2, assuming US$80/bbl Brent and a 10.0% discount rate, to changes in the following variables:
  - variations of +/- 20% in capital expenditure costs (as recommended by RISC);
  - variations of +/- 10% in operating costs (as recommended by RISC);
  - premium over the Brent received for the oil in the US$2.00-6.00/bbl range. This range is consistent with the range of premiums the joint venture has received since 2011;
  - the outcome of the sensitivity analysis is summarised below:



These sensitivities do not, and do not purport to, represent the full range of potential value outcomes for the Maari field. They are simply theoretical indicators of the sensitivity of the net present values derived from the DCF analysis. In this regard, the net present value outcomes show a relatively wide range across the different scenarios, highlighting the sensitivity to relatively small changes in assumptions.

- based on the current understanding of the field, Maari could technically produce well beyond 2030 (although, given Grant Samuel's oil price assumptions, it is not economic to do so beyond 2029 based on the assumptions for Scenario 1 or beyond 2027 based on the assumptions for Scenario 2). The established field infrastructure and exploration potential in the vicinity of the Maari field combined with the field's long life results in real option value that is not captured in the net present values set out above.

5.4.2 Sampang

Grant Samuel has valued Cue Energy's 15% interest in the Sampang PSC in the range US$12-16 million, based on estimates of value for its interest in the Wortel field of US$11-13 million and a further US$1-3 million for its interest in Oyong.

Grant Samuel has valued Cue Energy's 15% interest in the Wortel field in the range US$11-13 million.

Grant Samuel developed a cash flow model for Wortel based on operating scenarios developed by RISC using development and production plans provided by Cue Energy:

- **Scenario 1** is based on historical production rates but incorporates benefits from the additional compression facilities that were installed at Grati in December 2014. Gas produced over the life of the field totals 46.4bscf. Minimal amounts of associated condensate are also extracted. RISC has adopted Cue Energy's operating and capital expenditure assumptions. Limited capital expenditure is incurred (the field is mature and no further capital investment is required) and operating expenditure over the life of the field totals US$186 million. The joint venture makes regular cash contributions to fund abandonment costs: the abandonment costs are therefore reflected in the annual cash flows; and

- **Scenario 2** is based on Scenario 1 and assumes greater benefits from the installed compression leading to the extraction of greater gas volumes from the field (and a commensurate increase in condensate volumes). Total production over the life of the field is 58.3bscf of gas. Operating and capital expenditures are the same as in Scenario 1 as they are largely fixed in nature.

The following table summarises the projected production and costs for the two scenarios:

Wortel – Model Parameters (100%)								
	Year ended 31 December							
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**Total**
Scenario 1								
Gas (bscf)	16.2	11.5	7.5	5.3	3.4	2.6	-	**46.4**
Condensate (mbbl)	16.2	7.4	4.8	3.4	2.2	1.7	-	**35.6**
Capex (US$m)	0.3	0.1	0.1	0.1	0.1	0.1	-	**0.9**
Opex (US$m)	36.3	30.0	30.0	30.0	30.0	30.0	-	**186.3**
Scenario 2								
Gas (bscf)	16.3	13.2	10.0	7.8	6.1	4.8	-	**58.3**
Condensate (mbbl)	16.3	8.4	6.4	5.0	3.9	3.1	-	**43.1**
Capex (US$m)	0.3	0.1	0.1	0.1	0.1	0.1	-	**0.9**
Opex (US$m)	36.3	30.0	30.0	30.0	30.0	30.0	-	**186.3**

RISC has explicitly forecasted production and costs to 31 December 2020 for both Scenarios to allow for the testing of the field's economic limit. In Scenario 1, Wortel reaches its economic limit at the end of 2018 and production is assumed to cease thereafter. In Scenario 2, Wortel produces until the end of 2020 although production in 2019 and 2020 contributes only marginally to the net present value.

Scenario 1 generates a net present value of US$12.0 million and Scenario 2 generates a net present value of US$14.6 million at a discount rate of 10% (Cue Energy share). As the gas price received by the joint venture is independent of the prevailing oil price and condensate contributes only marginally to revenue, changes in the oil price assumptions have an immaterial impact on the net present values. Furthermore, the calculated net present values are only marginally affected by changes in discount rates.

The value attributed by Grant Samuel to Cue Energy's Wortel interest in the range US$11-13 million takes into account the analysis set out above as well as the following factors:

- there is limited production history since the installation of additional compression at Grati in December 2014 upon which to base decline curve analysis to derive production forecasts;
- there is a risk that Oyong gas, which is sold at a much lower price than Wortel gas, could displace Wortel gas volumes in the pipeline linking the offshore facilities to the Grati plant;
- no salvage value has been attributed to the Grati plant. Upon completion of production at Wortel and Oyong, all rights to use the plant will revert to the Indonesian government. In particular, the Sampang PSC joint venture will have no right to sell processing capacity to third parties or to sell the plant;
- Scenario 2 is an upside case. It assumes that the additional compression is more effective than the design expectation. While this outcome is plausible, it remains to be demonstrated; and
- given the limited remaining project life and, in particular, the restrictions on the use of the Grati plant, there is limited real option value in the project.

Grant Samuel has valued Cue Energy's 15% interest in the Oyong field in the range US$1-3 million.

Grant Samuel developed a cash flow model for Oyong based on operating scenarios developed by RISC using development and production plans provided by Cue Energy:

- **Scenario 1** is based on historical production rates and decline curves at the Oyong field and assumes that the field will produce as expected following the completion of the workover program in January 2015. Oil and gas produced over the life of the field is 1.7mmbbl and 27.4bscf respectively. RISC has adopted Cue Energy's operating and capital expenditure assumptions. Limited capital expenditure is incurred (the field is mature and a workover program has recently been completed) and operating expenditure over the life of the field totals US$172 million. As is the case for Wortel, the abandonment costs are reflected in the annual cash flows; and

- **Scenario 2** is based on Scenario 1 and assumes higher production resulting in total production over the life of the field of 2.5mmbbl of oil and 39.8bscf. Operating and capital expenditures remain the same as they are largely fixed in nature.

The following table summarises the projected production and costs for the two scenarios:

Oyong – Model Parameters (100%)

	Year ended 31 December							
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**Total**
Scenario 1								
Oil (mbbl)	501	476	313	205	134	87	-	**1,716**
Gas (bscf)	8.0	7.6	5.0	3.3	2.1	1.4	-	**27.4**
Capex (US$m)	0.3	0.1	0.1	0.1	0.1	0.1	-	**0.9**
Opex (US$m)	37	27	27	27	27	27	-	**172**
Scenario 2								
Oil (mbbl)	501	534	456	389	331	281	-	**2,493**
Gas (bscf)	8.0	8.5	7.3	6.2	5.3	4.5	-	**39.8**
Capex (US$m)	0.3	0.1	0.1	0.1	0.1	0.1	-	**0.9**
Opex (US$m)	37	27	27	27	27	27	-	**172**

RISC has explicitly forecast production and costs to 31 December 2020 for both scenarios to allow for the testing of the field's economic limit. In Scenario 1, Oyong reaches its economic limit at the end of 2017 and production is assumed to cease thereafter. In Scenario 2, Oyong produces until the end of 2020, although production in 2019 and 2020 contributes only marginally to the net present value.

Variations in the long term oil price and the discount rate have a limited impact on the calculated net present values of Cue Energy's interest in the Oyong field reflecting the short life of the field and the fact that gas, which is sold at a fixed price (i.e. at a price not linked to the oil price), accounts for approximately one third of the revenue. Scenario 1 generates a net present value of US$1.6 million and Scenario 2 generates a net present value of US$2.9 million at a discount rate of 10% (Cue Energy share).

The value attributed by Grant Samuel to Cue Energy's Oyong interest in the range of US$1-3 million takes into account the analysis set out above as well as the following factors:

- there is limited production history since workovers were completed in January 2015 but evidence points to very mixed results. Three of the four workovers were not successful while the fourth has so far resulted in production rates exceeding expectations for the whole program. There is therefore significant uncertainty as to future production rates;

- the production scenarios assume that the joint venture is successful in extending the lease over the FSO beyond September 2015;
- Scenario 2 is an upside case, which, while realistic, assumes better than expected production outcomes; and
- no salvage value has been attributed to the Grati plant.

5.4.3 Exploration

RISC has attributed a value of $10-20 million to Cue Energy's exploration interests, which represents RISC's estimate of the price that an acquirer would be willing to pay for the exploration portfolio as a whole.

RISC valued each exploration asset separately as summarised in the table below:

Exploration Assets (Cue Energy Share)

	RISC Value Range		
US$ millions	**Low**	**Mid**	**High**
Mahakam Hilir	4.2	8.4	16.8
Mahato	1.1	2.5	3.9
Jeruk	0.0	0.0	0.0
Australia	0.0	0.0	9.9
New Zealand	1.9	2.9	6.9
Total	**7.2**	**13.8**	**35.7**

Source: RISC

While the sum of the low and high estimates are $7.2 million and $37.5 million, RISC notes that it is unlikely that a buyer of the exploration portfolio would value all the assets at either the low or the high end of the valuation range. RISC has attributed a value in the range of $10-20 million to the portfolio sold as a whole.

The exploration values tabled above are net of expenditure commitments totalling $22 million, the majority of which is expected to be spent in 2015.

Mahakam Hilir contributes the bulk of RISC's assessed exploration values. While drilling to date has not resulted in a discovery, there are several parallel geological trends hosting large oil fields in the area. Cue Energy has identified a large structure for drilling.

Notwithstanding RISC's valuation range for Cue Energy's exploration assets of US$10-20 million, the ultimate value of Cue Energy's exploration interests could fall outside this range. Exploration drilling results can be binary, with successful outcomes generating substantial value but failure effectively resulting in value falling to zero. Accordingly, the value of Cue Energy's exploration interests (and more broadly the overall exploration program, including the expenditure commitments) could ultimately be significantly greater than the current estimates of value. On the other hand, it is also possible that the ultimate value will be far less than current estimates.

5.5 Other Assets and Liabilities

Cue Energy's other assets and liabilities have been valued in the range of negative $1-2 million and include:

- a net liability of approximately US$4 million relating to arrangements at the Jeruk field, which is equivalent to $5 million based on prevailing AUD:USD exchange rates;

- an insurance payout expected to be received in relation to the 2013 suspension of production and associated repair costs at Maari. Cue Energy's share of costs was approximately US$4 million. Grant Samuel has attributed a value of approximately $3 million (tax-effected, based on prevailing AUD:USD exchanges rates) based on discussions with Cue Energy management; and
- an adjustment of negative $4 million for various working capital items, including a net payable in relation to Sampang (principally related to Indonesian tax payable).

No allowance has been made for the value of Cue Energy's Australian tax losses. Cue Energy has no short to medium plans to utilise these tax losses.

5.6 Corporate Costs/ Head Office Costs

Cue Energy incurs head office costs of approximately $6.5 million per annum, which are not reflected in the cash flow models developed for the discounted cash flow analysis of Cue Energy's Maari, Wortel and Oyong assets. These head office costs consist of costs associated with:

- the Cue Energy executive office (such as costs associated with the offices of the Managing Director and Chief Financial Officer, company secretarial and legal, planning and development, corporate affairs, treasury, tax etc.);
- the maintenance of a listed company (such as directors fees, annual reports and shareholder communications, share registry and listing fees);
- the provision of technical support to Cue Energy's producing assets; and
- Cue Energy's business development efforts, including exploration at the company's properties and assessing investment opportunities.

Cue Energy's asset portfolio consists mainly of minority interests in non-operated assets. While head office provides support to the operations, it is likely that an acquirer would be able to save most if not all of Cue Energy's head office costs. One-off transaction costs would be incurred. An allowance of $2-4 million has been made in the valuation for the capitalised value of the residual corporate costs and one-off implementation costs.

5.7 Cash

Cue Energy's net cash for valuation purposes is $39 million. This amount is based on the company's cash holdings as at 31 December 2014 of US$29.8 million, NZ$0.2 million and A$0.5 million converted at the relevant US$:A$ and NZ$:A$ exchange rates as at 26 February 2015.

6 Evaluation of the Offer

6.1 Conclusion

Grant Samuel has concluded that the Offer is neither fair nor reasonable.

6.2 Fairness

Grant Samuel has estimated that the full underlying value of Cue Energy (including a premium for control) is in the range 11.7-15.2 cents per share. The valuation is set out in Section 5 of this report.

The Offer of 10 cents per share falls below the bottom end of the valuation range of 11.7-15.2 cents per share. Accordingly, the Offer is not fair.

6.3 Reasonableness

6.3.1 Overview

An offer can be reasonable notwithstanding that it is not fair if there are compelling reasons for shareholders to accept the offer. This is generally the case when shareholders have no realistic prospect of realising value greater than the offer price, commonly because the bidder already has a controlling interest in the target company. In the case of the Offer for the shares in Cue Energy, Grant Samuel has considered the following factors:

- the Offer price of 10 cents per share is approximately 15% lower than the bottom end of Grant Samuel's valuation range of 11.7-15.2 cents per share;
- takeover premium analysis in relation to the NZOG offer is inconclusive. It does not provide any compelling rationale to accept the Offer, given Grant Samuel's conclusion that the Offer is not fair;
- while in Grant Samuel's view Cue Energy's share price could be expected to fall back below the NZOG Offer price in the absence of an offer (assuming no material change in market conditions and Cue Energy's circumstances), it is reasonable to expect that the Cue Energy share price would be supported by the potential for future corporate activity involving Cue Energy;
- NZOG's 20.11% shareholding is not an absolute impediment to a higher alternative offer in the future, particularly given the structure of NZOG's share register; and
- since the announcement of the Offer, Cue Energy's shares have generally traded above 10 cents. As long as Cue Energy shareholders can realise more than 10 cents per share by selling their shares on market, there is no reason for shareholders to sell their shares into the NZOG Offer.

These issues are analysed in more detail below.

6.3.2 Premium for Control

The consideration of 10 cents per share represents an 11% premium to the price at which Cue Energy shares last traded prior to the announcement of the Offer.

Cue Energy – Premium over Pre-announcement Prices		
Period	**Price/VWAP**	**Premium/(Discount)**
Closing – Pre-announcement price	9.00¢	11%
1 week prior to 11 February 2015 - VWAP[19]	8.86¢	13%
1 month prior to 11 February 2015 – VWAP	8.73¢	15%
3 months prior to 11 February 2015 - VWAP	8.09¢	24%
6 months prior to 11 February 2015 - VWAP	9.34¢	7%
12 months prior to 11 February 2015 – VWAP	10.51¢	(5%)
19 December 2014 – Pre initial acquisition	8.50¢	18%
1 week prior to 19 December 2014 – VWAP	7.72¢	29%
1 month prior to 19 December 2014 – VWAP	8.00¢	25%

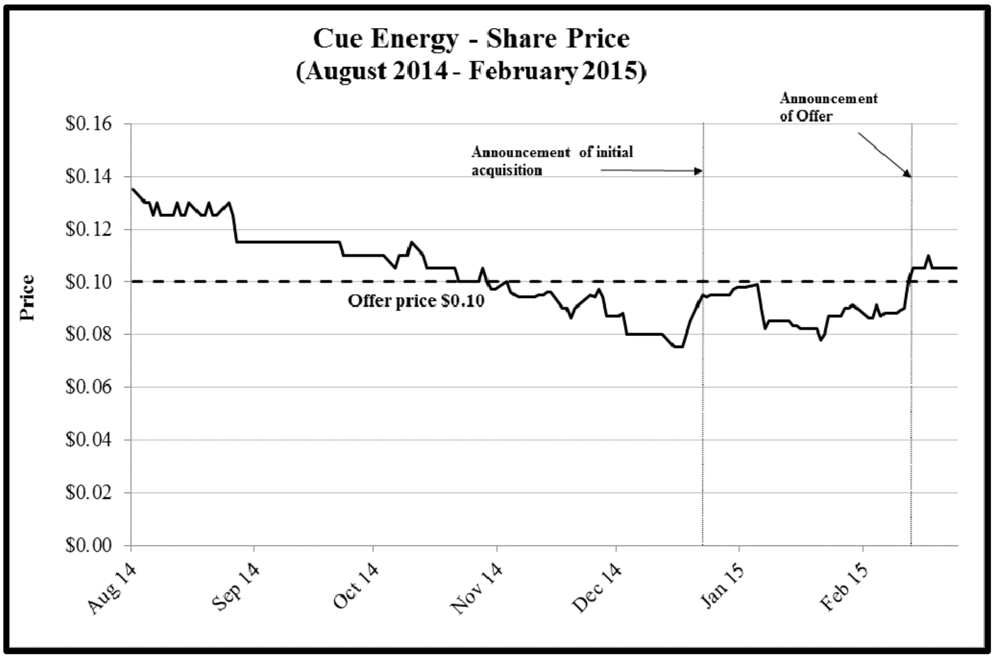
The level of premiums observed in takeovers varies depending on the circumstances of the target and other factors (such as the potential for competing offers) but tends to fall in the range 20-35%. However, it is important to recognise that:

- premiums for control are an outcome not a determinant of value; and
- premiums vary widely depending on individual circumstances. In fact, some studies show that the majority of transactions actually fall outside this "standard" range.

The Offer price represents modest premiums relative to the Cue Energy share price immediately before the announcement of the Offer. The premium is even lower (7%) when compared to the volume weighted average prices ("VWAP") for the six months prior to the announcement and the Offer represents a discount (5%) when compared to prices over 12 months.

However, premium analysis in this context must be treated with considerable caution. The announcement on 22 December 2014 of the initial acquisition by NZOG resulted in an increase of around 12% in the Cue Energy share price. It is possible that trading in Cue Energy shares immediately prior to the announcement of the Offer incorporated an element of control premium, reflecting speculation as to some form of corporate transaction involving NZOG. This arguably suggests that the relevant benchmark against which to measure the offer premium is the unaffected Cue Energy share price prior to 22 December 2014, as illustrated in the following graph:

[19] VWAP is volume weighted average price.



Source: IRESS

The Offer price reflects much larger premiums relative to these pre-announcement share prices. In particular, the premium relative to Cue Energy's closing price on 19 December 2014 (the last trading price before the announcement of NZOG's acquisition) is 18%. The premium over the VWAP for the week prior to the announcement of NZOG's initial acquisition is 29%, while the premium relative to the VWAP for the month prior to the announcement is 25%. Movements in the oil price since then complicate the premium analysis. Since reaching a six year low on 26 January 2015 of US$45.25/bbl, the oil price has recovered significantly to recent levels around US$60/bbl.

The Offer premium is much lower (and for some time periods represents a discount) if measured against share prices in the period before December 2014. However, it should be recognised that the higher Cue Energy share prices in the period before December 2014 reflected, at least in part, higher oil prices (the oil price fell from approximately US$115/bbl (Brent) on 19 June 2014 to US$55/bbl at 31 December 2014). Accordingly, premium analysis based on longer run Cue Energy share prices provides little useful evidence for assessing the Offer.

More broadly, the limited liquidity of Cue Energy shares (with approximately 56% of its shares on issue held by its top four shareholders) means that Cue Energy's share price is not necessarily a good indicator of the underlying value of Cue Energy's assets. In this context, premium analysis may not be particularly meaningful.

The Offer represents only a modest premium to Cue Energy's pre-Offer share prices. The premiums relative to Cue Energy share prices for the month immediately prior to the announcement of NZOG's acquisition of a 19.99% interest in Cue Energy are more consistent with the premiums commonly paid in takeovers. However, that trading period was of short duration and saw only limited trading volumes. Subsequent shifts in the oil price make it difficult to form any firm view as to whether premiums for that period continue to be relevant. Overall, in Grant Samuel's view, the premium analysis is not conclusive.

6.3.3 Share Trading in the absence of the Offer

It is difficult to form any confident view as to the price at which Cue Energy shares would trade in the absence of the Offer. Cue Energy shares traded at prices above 10 cents per share for most of 2014. However, these share prices at least in part reflected the much higher oil prices that prevailed for the earlier months of 2014. While oil prices have recovered somewhat from their lows in late January 2015 and market participants generally expect a further strengthening of the oil price to the approximate range US$75-85/bbl over the medium term, there can be no guarantee that oil prices will return to the much higher prices that applied during the first half of 2014.

Cue Energy shares traded at prices well below the Offer price (generally in the range 8-9 cents) for the three weeks prior to the announcement on 22 December 2014 of NZOG's acquisition of its 19.99% interest in Cue Energy, and then again through much of January 2015. On the other hand, the oil price has strengthened by around 30% since reaching a six year low in late January 2015. NZOG's shareholding does not represent any significant further concentration of the register (given that NZOG acquired an existing substantial shareholding) and accordingly there should be no material impact on liquidity. While Cue Energy shares may trade below 10 cents in the absence of the Offer, it is likely that the Cue Energy share price would be supported to some extent by market perceptions that Cue Energy continued to be an attractive takeover target (assuming the continuation of current market conditions and no material changes in Cue Energy's circumstances).

6.3.4 Alternatives

In weighing up any offer, shareholders need to have regard to the alternatives that are realistically available to them. In relation to the Offer:

- the Offer price of 10 cents per share is approximately 15% lower than the bottom end of Grant Samuel's valuation range of 11.7-15.2 cents per share;

- NZOG's shareholding (20.11% as at 26 February 2015) is not an absolute impediment to some alternative change of control transaction involving Cue Energy. Cue Energy's next three largest shareholders collectively hold approximately 36% of the shares in Cue Energy and would be in a position to deliver control of Cue Energy to an alternative bidder. However, it must be recognised that NZOG's shareholding would be a deterrent to an alternative bid for Cue Energy;

- the prospects for Cue Energy shareholders of realising greater value through some alternative transaction (whether from a third party or through some subsequent higher offer from NZOG), will be enhanced to the extent that NZOG receives only minimal acceptances under its current Offer;

- since the announcement of the Offer, Cue Energy shares have generally traded at prices higher than the Offer of 10 cents per share. Between the announcement of the Offer on 12 February 2105 and 26 February 2015, a total of 14,841,119 Cue Energy shares traded at a volume weighted average price of approximately 10.4 cents. Of these, 1,574,993 traded at 10 cents, with the remaining 13,266,126 shares trading at prices higher than 10 cents. Accordingly, Cue shareholders have had an opportunity to realise cash value in excess of the Offer price through selling their shares on market. For as long as Cue Energy shares continue to trade at prices above 10 cents, shareholders have no incentive to sell their shares into the NZOG Offer.

6.3.5 Conclusion

Having regard to the above, Grant Samuel has concluded that, on balance, the Offer is not reasonable. Grant Samuel's conclusion could change in different circumstances, including in circumstances in which control had passed to NZOG, the liquidity of Cue Energy shares had been materially affected, or it had become otherwise apparent that Cue Energy shareholders had limited prospects in the short to medium term of realising value greater than the Offer price of 10 cents per share.

6.4 Shareholder Decision

Grant Samuel has been engaged to prepare an independent expert's report setting out whether in its opinion the Offer is fair and reasonable to shareholders and to state reasons for that opinion. Grant Samuel has not been engaged to provide a recommendation to shareholders in relation to the Offer, the responsibility for which lies with the directors of Cue Energy.

In any event, the decision whether to accept or reject the Offer is a matter for individual shareholders based on shareholders' views as to value, their expectations about future market conditions and their particular circumstances including risk profile, liquidity preference, investment strategy, portfolio structure and tax position. In particular, taxation consequences may vary from shareholder to shareholder. If in any doubt as to the action they should take in relation to the Offer, shareholders should consult their own professional adviser.

Similarly, it is a matter for individual shareholders as to whether to buy, hold or sell shares in Cue Energy. This is an investment decision upon which Grant Samuel does not offer an opinion and is independent of a decision on whether to accept the Offer. Shareholders should consult their own professional adviser in this regard.

7 Qualifications, Declarations and Consents

7.1 Qualifications

The Grant Samuel group of companies provide corporate advisory services (in relation to mergers and acquisitions, capital raisings, debt raisings, corporate restructurings and financial matters generally) and provides marketing and distribution services to fund managers. The primary activity of Grant Samuel & Associates Pty Limited is the preparation of corporate and business valuations and the provision of independent advice and expert's reports in connection with mergers and acquisitions, takeovers and capital reconstructions. Since inception in 1988, Grant Samuel and its related companies have prepared more than 500 public independent expert and appraisal reports.

The person responsible for preparing this report on behalf of Grant Samuel is Stephen Cooper. Stephen has a significant number of years of experience in relevant corporate advisory matters. Matt Leroux MEng MBA, David Szeleczky BCom (Hons) LLB (Hons) GCertAppFin and Shakeel Mohammed MS MBA assisted in the preparation of the report. Each of the above persons is a representative of Grant Samuel pursuant to its Australian Financial Services Licence under Part 7.6 of the Corporations Act.

7.2 Disclaimers

It is not intended that this report should be used or relied upon for any purpose other than as an expression of Grant Samuel's opinion as to whether the Offer is fair and reasonable to shareholders. Grant Samuel expressly disclaims any liability to any Cue Energy shareholder who relies or purports to rely on the report for any other purpose and to any other party who relies or purports to rely on the report for any purpose whatsoever.

Grant Samuel has had no involvement in the preparation of the Target's Statement issued by Cue Energy and has not verified or approved any of the contents of the Target's Statement. Grant Samuel does not accept any responsibility for the contents of the Target's Statement (except for this report).

7.3 Independence

Grant Samuel and its related entities do not have at the date of this report, and have not had within the previous two years, any business or professional relationship with Cue Energy, NZOG or NZOG Offshore or any financial or other interest that could reasonably be regarded as capable of affecting its ability to provide an unbiased opinion in relation to the Offer.

Grant Samuel had no part in the formulation of the Offer. Its only role has been the preparation of this report.

Grant Samuel will receive a fixed fee of $200,000 for the preparation of this report. This fee is not contingent on the conclusions reached or the outcome of the Offer. Grant Samuel's out of pocket expenses in relation to the preparation of the report will be reimbursed. Grant Samuel will receive no other benefit for the preparation of this report.

Grant Samuel considers itself to be independent in terms of Regulatory Guide 112 issued by ASIC on 30 March 2011.

7.4 Declarations

Cue Energy has agreed that it will indemnify Grant Samuel and its employees and officers in respect of any liability suffered or incurred as a result of or in connection with the preparation of the report. This indemnity will not apply in respect of the proportion of any liability found by a court to be primarily caused by any conduct involving gross negligence or wilful misconduct by Grant Samuel. Cue Energy has also agreed to indemnify Grant Samuel and its employees and officers for time spent and reasonable legal costs and expenses incurred in relation to any inquiry or proceeding initiated by any person. Any claims by Cue Energy are limited to an amount equal to the fees paid to Grant Samuel. Where Grant Samuel or its employees and officers are found to have been grossly negligent or engaged in wilful misconduct Grant Samuel shall bear the proportion of such costs caused by its action.

Advance drafts of this report were provided to Cue Energy and its advisers. Certain changes were made to the drafting of the report as a result of the circulation of the draft report. Following Grant Samuel's provision of a full draft report to Cue Energy, RISC provided Grant Samuel with updated production forecasts for the Maari asset. The updated production forecasts were lower than the forecasts previously provided by RISC to Grant Samuel. Having regard to discounted cash flow analysis based on the revised production forecasts, Grant Samuel reduced its valuation of Cue Energy by 0.8 cents per share at both the top and bottom ends of the valuation range. Other than this change, the issuing of the drafts did not result in any alteration to the methodology, evaluation or conclusions in the report.

7.5 Consents

Grant Samuel consents to the issuing of this report in the form and context in which it is to be included in the Target's Statement to be sent to shareholders of Cue Energy. Neither the whole nor any part of this report nor any reference thereto may be included in any other document without the prior written consent of Grant Samuel as to the form and context in which it appears.

7.6 Other

The accompanying letter dated 28 February 2015 and the Appendices form part of this report.

Grant Samuel has prepared a Financial Services Guide as required by the Corporations Act. The Financial Services Guide is set out at the beginning of this report.

GRANT SAMUEL & ASSOCIATES PTY LIMITED
28 February 2015

Grant Samuel & Associates

Appendix 1

Selection of Discount Rate

1 Overview

A discount rate in the range of 9.5-10.5% has been selected as appropriate to apply to the forecast nominal ungeared after tax US$ denominated cash flows for Cue Energy's oil and gas assets.

Selection of the appropriate discount rate to apply to the forecast cash flows of any business enterprise is fundamentally a matter of judgement. The valuation of an asset or business involves judgements about the discount rates that may be utilised by potential acquirers of that asset. There is a body of theory which can be used to support that judgement. However, a mechanistic application of formulae derived from that theory can obscure the reality that there is no "correct" discount rate. Despite the growing acceptance and application of various theoretical models, it is Grant Samuel's experience that many companies rely on less sophisticated approaches. Many businesses and investors use relatively arbitrary "hurdle rates" which do not vary significantly from investment to investment or change significantly over time despite interest rate movements. Valuation is an estimate of what real world buyers and sellers of assets would pay and must therefore reflect criteria that will be applied in practice even if they are not theoretically correct. Grant Samuel considers the rates adopted to be reasonable discount rates that acquirers would use irrespective of the outcome of any particular theoretical model.

The discount rate that Grant Samuel has adopted is reasonable relative to the rates derived from theoretical models. The discount rate represents an estimate of the weighted average cost of capital ("WACC") appropriate for these assets. Grant Samuel has calculated a WACC based on a weighted average of the cost of equity and the cost of debt. This is the relevant rate to apply to ungeared cash flows. There are three main elements to the determination of an appropriate WACC. These are:

- cost of equity;
- cost of debt; and
- debt/equity mix.

WACC is a commonly used basis but it should be recognised that it has shortcomings in that it:

- represents a simplification of what are usually much more complex financial structures; and
- assumes a constant degree of leverage which is seldom correct.

In selecting the discount rate range, we utilised the capital asset pricing model ("CAPM") as the starting point in our analysis to determine a cost of equity. However, it is easy to credit the output of models with a precision it does not warrant. The reality is that any cost of capital estimate or model output should be treated as a broad guide rather than an absolute truth. The cost of capital is fundamentally a matter of judgement, not merely a calculation. In this context, regard was also had to market evidence that suggests that equity investors have substantially repriced risk since the global financial crisis and the fact that interest rates are at low levels by comparison with historical norms.

The CAPM is probably the most widely accepted and used methodology for determining the cost of equity capital. There are more sophisticated multivariate models which utilise additional risk factors but these models have not achieved any significant degree of usage or acceptance in practice. However, while the theory underlying the CAPM is rigorous the practical application is subject to shortcomings and limitations and the results of applying the CAPM model should only be regarded as providing a general guide. There is a tendency to regard the rates calculated using CAPM as inviolate. To do so is to misunderstand the limitations of the model. For example:

- the CAPM theory is based on expectations but uses historical data as a proxy. The future is not necessarily the same as the past;
- the measurement of historical data such as risk premia and beta factors is subject to very high levels of statistical error. Measurements vary widely depending on factors such as source, time period and sampling frequency;

- the measurement of beta is often based on comparisons with other companies. None of these companies is likely to be directly comparable to the entity for which the discount rate is being calculated and may operate in widely varying markets;
- parameters such as the debt/equity ratio and risk premium are based on subjective judgements; and
- there is not unanimous agreement as to how the model should adjust for factors such as taxation. The CAPM was developed in the context of a "classical" tax system. Australia's system of dividend imputation has a significant impact on the measurement of net returns to investors.

In addition, the market upheaval since 2007 has seen a repricing of risk by investors and global interest rates, including long term bond rates, remain at low levels in comparison with historical norms. The CAPM methodology does not readily allow for these types of events. Strict application of the CAPM at the present time gives results that are arguably unrealistically low and are often inconsistent with other measures.

The cost of debt has been determined by reference to the pricing implied by the debt markets in the United States. The cost of debt represents an estimate of the expected future returns required by debt providers. In determining the appropriate cost of debt over this forecast period, regard was had to debt ratings of comparable companies.

Selection of an appropriate debt/equity mix is a matter of judgement. The debt/equity mix represents an appropriate level of gearing, stated in market value terms, for the business over the forecast period. The relevant proportions of debt and equity have been determined having regard to the financial gearing of the industry in general and comparable companies, and judgements as to the appropriate level of gearing considering the nature and quality of the cash flow stream.

The following sections set out the basis for Grant Samuel's determination of the discount rates for Cue Energy's oil and gas assets and the factors which limit the accuracy and reliability of the estimates.

2 Definition and Limitations of the CAPM and WACC

The CAPM provides a theoretical basis for determining a discount rate that reflects the returns required by diversified investors in equities. The rate of return required by equity investors represents the cost of equity of a company and is therefore the relevant measure for estimating a company's weighted average cost of capital. CAPM is based on the assumption that investors require a premium for investing in equities rather than in risk free investments (such as United States government bonds). The premium is commonly known as the market risk premium and notionally represents the premium required to compensate for investment in the equity market in general.

The risks relating to a company or business may be divided into specific risks and systematic risks. Specific risks are risks that are specific to a particular company or business and are unrelated to movements in equity markets generally. While specific risks will result in actual returns varying from expected returns, it is assumed that diversified investors require no additional returns to compensate for specific risk, because the net effect of specific risks across a diversified portfolio will, on average, be zero. Portfolio investors can diversify away all specific risk.

However, investors cannot diversify away the systematic risk of a particular investment or business operation. Systematic risk is the risk that the return from an investment or business operation will vary with the market return in general. If the return on an investment was expected to be completely correlated with the return from the market in general, then the return required on the investment would be equal to the return required from the market in general (i.e. the risk free rate plus the market risk premium).

Systematic risk is affected by the following factors:

- financial leverage: additional debt will increase the impact of changes in returns on underlying assets and therefore increase systematic risk;
- cyclicality of revenue: projects and companies with cyclical revenues will generally be subject to greater systematic risk than those with non-cyclical revenues; and

- operating leverage: projects and companies with greater proportions of fixed costs in their cost structure will generally be subject to more systematic risk than those with lesser proportions of fixed costs.

CAPM postulates that the return required on an investment or asset can be estimated by applying to the market risk premium a measure of systematic risk described as the beta factor. The beta for an investment reflects the covariance of the return from that investment with the return from the market as a whole. Covariance is a measure of relative volatility and correlation. The beta of an investment represents its systematic risk only. It is not a measure of the total risk of a particular investment. An investment with a beta of more than one is riskier than the market and an investment with a beta of less than one is less risky. The discount rate appropriate for an investment which involves zero systematic risk would be equal to the risk free rate.

The formula for deriving the cost of equity using CAPM is as follows:

$$Re = Rf + Beta\ (Rm - Rf)$$

Where:

Re	=	the cost of equity capital;
Rf	=	the risk free rate;
Beta	=	the beta factor;
Rm	=	the expected market return; and
Rm - Rf	=	the market risk premium.

The beta for a company or business operation is normally estimated by observing the historical relationship between returns from the company or comparable companies and returns from the market in general. The market risk premium is estimated by reference to the actual long run premium earned on equity investments by comparison with the return on risk free investments.

The formula conventionally used to calculate a WACC under a classical tax system is as follows:

$$WACC = (Re \times E/V) + (Rd \times (1-t) \times D/V)$$

Where:

E/V	=	the proportion of equity to total value (where V = D + E);
D/V	=	the proportion of debt to total value;
Re	=	the cost of equity capital;
Rd	=	the cost of debt capital; and
t	=	the corporate tax rate

The models, while simple, are based on a sophisticated and rigorous theoretical analysis. Nevertheless, application of the theory is not straightforward and the discount rate calculated should be treated as no more than a general guide. The reliability of any estimate derived from the model is limited. Some of the issues are discussed below:

- **Risk Free Rate**

  Theoretically, the risk free rate used should be an estimate of the risk free rate in each future period (i.e. the one year spot rate in that year if annual cash flows are used). There is no official "risk free" rate but rates on government securities are typically used as an acceptable substitute. More importantly, forecast rates for each future period are not readily available. In practice, the long term Commonwealth Government Bond rate is used as a substitute in Australia and medium to long term Treasury Bond rates are used in the United States. It should be recognised that the yield to maturity of a long term bond is only an average rate and where the yield curve is strongly positive (i.e. longer term rates are significantly above short term rates) the adoption of a single long term bond rate has the effect of reducing the net present value where the major positive cash flows are in the initial years. The long term bond rate is therefore only an approximation.

  The ten year bond rate is a widely used and accepted benchmark for the risk free rate. Where the forecast period exceeds ten years, an issue arises as to the appropriate bond to use. While longer term bond rates are available, the ten year bond market is the deepest long term bond market in

Australia and is a widely used and recognised benchmark. There is a very limited market for bonds of more than ten years. In the United States, there are deeper markets for longer term bonds. The 30 year bond rate is a widely used benchmark. However, long term rates accentuate the distortions of the yield curve on cash flows in early years. In any event, a single long term bond rate matching the term of the cash flows is no more theoretically correct than using a ten year rate. More importantly, the ten year rate is the standard benchmark used in practice.

Cue Energy's oil and gas assets have relatively modest lives and majority of the cash flows are forecast to be generated within the next 5-7 years, a case could be made to use yields on shorter term Treasury Bonds. Grant Samuel has however adopted the ten year bond rate reflecting market practice.

- **Market Risk Premium**

The market risk premium (*Rm - Rf*) represents the "extra" return that investors require to invest in equity securities as a whole over risk free investments. This is an "ex-ante" concept. It is the expected premium and as such it is not an observable phenomenon. There is no generally accepted approach to estimating a forward looking market risk premium and therefore the historical premium is used as the best available proxy measure. The premium earned historically by equity investments is usually calculated over a time period of many years, typically at least 30 years. This long time frame is used on the basis that short term numbers are highly volatile and that a long term average return would be a fair indication of what most investors would expect to earn in the future from an investment in equities with a 5-10 year time frame.

In the United States it is generally believed that the premium is in the range of 5-6% but there are widely varying assessments (from 3% to 9%). Australian studies have been more limited and mainly derive from the Officer Study[1] which was based on data for the period 1883 to 1987 (prior to the introduction of dividend imputation) and indicated that the long run average premium was in the order of 8% using an arithmetic average but subject to significant statistical error[2]. More recently, the Officer Study has been updated to 2011[3] with the long term average declining to around 6%. However, due to concerns about the earlier market data, Officer now places emphasis on the average risk premium since 1958 which is estimated to be 5.9% ignoring the impact of imputation[4].

In addition, the market risk premium is not constant and changes over time. At various stages of the market cycle investors perceive that equities are more risky than at other times and will increase or decrease their expected premium. Indeed, prior to 2008 there were arguments being put forward that the risk premium was lower than it had been historically while today there is evidence to indicate that current market risk premiums are above historical averages. However, there is no accepted approach to deal with changes in market risk premia for current conditions.

In the absence of controls over capital flows, differences in taxation and other regulatory and institutional differences, it is reasonable to assume that the market risk premium should be approximately equal across markets which exhibit similar risk characteristics after adjusting for the effects of expected inflation differentials. Accordingly, it is reasonable to assume similar market risk premiums for first world countries enjoying political economic stability, such as Australia, New Zealand, the United States, Japan, the United Kingdom and various western European countries.

- **Beta Factor**

The beta factor is a measure of the expected covariance (i.e. volatility and correlation of returns) between the return on an investment and the return from the market as a whole. The expected beta factor cannot be observed. The conventional practice is to calculate an historical beta from past

1 R.R. Officer in Ball, R., Brown, P., Finn, F. J. & Officer, R. R., "Share Market and Portfolio Theory: Readings and Australian Evidence" (second edition), University of Queensland Press, 1989 ("Officer Study").

2 The "true" figure lies within a range of approximately 2-10% at a 95% confidence level.

3 Dr. S. Bishop and Professor R.R. Officer, "Review of Debt Risk Premium and Market Risk Premium" (February 2013), prepared for Aurizon Holdings Limited.

4 Where the market return explicitly includes a component for imputation benefits of 1.0 the market risk premium over the same period is around 6.5%.

share price data and use it as a proxy for the future but it must be recognised that the expected beta is not necessarily the same as the historical beta. A company's relative risk does change over time.

The appropriate beta is the beta of the company being acquired rather than the beta of the acquirer (which may be in a different business with different risks). Betas for the particular subject company may be utilised. However, it is also appropriate (and may be necessary if the investment is not listed) to utilise betas for comparable companies and sector averages (particularly as those may be more reliable).

However, there are very significant measurement issues with betas which mean that only limited reliance can be placed on such statistics. There is no "correct" beta. For example:

- over the last three years Cue Energy's beta as measured by SIRCA Limited ("SIRCA") has varied between 1.05 and 1.77 and was measured at 1.05 at 30 September 2014; and
- the standard error of SIRCA's estimate of Cue Energy's beta has generally been in the order of 0.47 meaning that for a beta of, say, 1.4 even at a 68% confidence level, the range is 0.93 to 1.87.

- **Debt/Equity Mix**

The tax deductibility of the cost of debt means that the higher the proportion of debt the lower the WACC, although this would be offset, at least in part, by an increase in the beta factor as leverage increases.

The debt/equity mix assumed in calculating the discount rate should be consistent with the level implicit in the measurement of the beta factor. Typically, the debt/equity mix changes over time and there is significant diversity in the levels of leverage across companies in a sector. There is a tendency to calculate leverage at a point in time whereas the leverage should represent the average over the period the beta was measured. This can be difficult to assess with a meaningful degree of accuracy.

The measured beta factors for listed companies are "equity" betas and reflect the financial leverage of the individual companies. It is possible to unleverage beta factors to derive asset betas and releverage betas to reflect a more appropriate or comparable financial structure. In Grant Samuel's view this technique is subject to considerable estimation error. Deleveraging and releveraging betas exacerbates the estimation errors in the original beta calculation and gives a misleading impression as to the precision of the methodology. Deleveraging and releveraging is also incorrectly calculated based on debt levels at a single point in time.

In addition, the actual debt and equity structures of most companies are typically relatively complex. It is necessary to simplify this for practical purposes in this kind of analysis.

Finally, it should be noted that, for this purpose, the relevant measure of the debt/equity mix is based on market values not book values.

- **Specific Risk**

The WACC is designed to be applied to "expected cash flows" which are effectively a weighted average of the likely scenarios. To the extent that a business is perceived as being particularly risky, this specific risk should be dealt with by adjusting the cash flow scenarios. This avoids the need to make arbitrary adjustments to the discount rate which can dramatically affect estimated values, particularly when the cash flows are of extended duration or much of the business value reflects future growth in cash flows. In addition, risk adjusting the cash flows requires a more disciplined analysis of the risks that the valuer is trying to reflect in the valuation.

However, it is also common in practice to allow for certain classes of specific risk (particularly sovereign and other country specific risks) in a different way by adjusting the discount rate applied to forecast cash flows.

3 Calculation of WACC

3.1 Cost of Equity Capital

The cost of equity capital has been estimated by reference to the CAPM. Grant Samuel has adopted a cost of equity capital in the range 9.3-9.9%.

- **Risk Free Rate**

  Grant Samuel has adopted a risk free rate of 2.1%. The risk free rate approximates the current yield to maturity on ten year United States Government bonds.

- **Market Risk Premium**

  Grant Samuel has consistently adopted a market risk premium of 6% and believes that this continues to be a reasonable estimate. It:

  - is not statistically significantly different to the premium suggested by long term historical data; and
  - is similar to that used by a wide variety of analysts and practitioners (typically in the range 5-7%).

- **Beta Factor**

  Grant Samuel has adopted a beta factor in the range 1.2-1.3 for the purposes of valuing Cue Energy's oil and gas assets.

  Grant Samuel has considered the beta factors for a wide range of Australian and international listed companies in the oil and gas industry in determining an appropriate beta for Cue Energy's oil and gas assets. The betas have been calculated on two bases relative to each company's home exchange index and relative to the Morgan Stanley Capital International Developed World Index ("MSCI"), an international equities market index that is widely used as a proxy for the global stockmarket as a whole. In Grant Samuel's view betas estimated by reference to the MSCI are generally more relevant than those estimated relative to the home indices, because they represent a better measure of investing in the resources sector.

  Grant Samuel has also considered betas estimated on the basis of share market data over various periods of time. Betas are, conceptually, estimates of the expected systematic risk added to a diversified portfolio by an investment (although they are estimated by reference to historical share market data). Estimates based on historical data do not necessarily reflect investor expectations.

  A summary of betas for selected comparable listed upstream oil and gas companies is set out in the table below. All of the international companies and some of the Australian Securities Exchange ("ASX") listed companies have investments assets in the Asia Pacific region. Of the ASX listed companies, Kina Petroleum Limited ("Kina") invests exclusively in Papua New Guinea while the others have investments located in both Australia and the Asia Pacific region.

Equity Beta Factors for Selected Listed Upstream Oil and Gas Companies							
Company	Market Capital-isation[5] ($ millions)	Monthly Observations over 5 years (Barra)[6]	Monthly Observations over 4 years			Weekly Observations over 2 years	
			SIRCA[7]	Bloomberg[8]		Bloomberg	
				Local	MSCI[9]	Local	MSCI
Cue Energy	**63**		**1.05**	**0.82**	**0.63**	**0.78**	**0.51**
Australia							
Production, Exploration and Development							
AWE	715		1.47	1.15	1.18	1.20	1.26
Drillsearch	459		1.84	1.18	1.12	1.46	1.27
Senex Energy	397		1.44	1.17	1.15	1.83	1.56
New Zealand Oil & Gas	209[10]		0.52	0.68	0.62	0.41	0.34
Horizon Oil	169		2.47	1.80	1.97	1.37	1.37
Cooper Energy	76		1.01	0.65	0.84	0.67	0.96
Exploration and Development							
Karoon Gas	676		2.88	1.60	2.30	1.65	1.54
Tap Oil	91		1.80	1.44	1.52	1.03	0.94
Kina Petroleum[11]	78		n.a.	n.a.	n.a.	0.32	0.56
International							
Production, Exploration and Development							
KrisEnergy[11]	623	na		na	n.a.	n.a.	n.a.
RH Petrogas	249	2.01		0.90	0.75	0.64	1.06
Loyz Energy	36	-0.07		1.01	1.27	0.72	0.15
PT Energi Mega	433	1.16		2.17	1.58	1.15	0.79
Exploration and Development							
Rex International[11]	429	na		na	na	na	n.a.

Source: SIRCA, Barra, Bloomberg

The table shows outcomes that suggest that determining a reliable beta for Cue Energy is not straightforward:

- Cue Energy's beta varies significantly depending on the measurement source (SIRCA, Bloomberg etc.) and has varied significantly over time. The beta estimates of Cue Energy are however lower than those of other ASX listed companies (except New Zealand Oil & Gas) and international peers;
- some individual company betas vary significantly depending on which market index is utilised (Local or MSCI); and
- gearing levels vary significantly but this is not always consistent with beta factors.

5 Based on share prices as at 20 February 2015 except for Cue Energy which is based on share prices as at 11 February 2015 (the last trading day prior to the announcement of the on-market takeover offer).

6 Barra, Inc. ("Barra") beta factors calculated as at 30 January 2015 over a period of 60 months using ordinary least squares regression or the Scholes-Williams technique (including lag) where the stock is thinly traded.

7 The Australian beta factors calculated by SIRCA as at 30 September 2014 over a period of 48 months using ordinary least squares regression or the Scholes-Williams technique where the stock is thinly traded.

8 Bloomberg betas have been calculated up to 20 February 2015. Grant Samuel understands that betas estimated by Bloomberg are not calculated strictly in conformity with accepted theoretical approaches to the estimation of betas (i.e. they are based on regressing total returns rather than the excess return over the risk free rate). However, in Grant Samuel's view the Bloomberg beta estimates can still provide a useful insight into the systematic risks associated with companies and industries. The figures used are the Bloomberg "adjusted" betas.

9 MSCI is calculated using local currency so that there is no impact of currency changes in the performance of the index.

10 On 29 January 2015, New Zealand Oil & Gas announced a capital return to shareholders through a share buyback arrangement with 1 in every 5 shares held to be bought back at NZ$0.75/share. The capital return and associated share cancellation was completed on 20 February 2015. Accordingly the shares outstanding and therefore the market capitalisation of the company have been adjusted to reflect the capital return.

11 Kina was listed on 19 December 2011 and there are insufficient data points to calculate four year betas. Rex International was listed in July 2013 and KrisEnergy was listed in July 2013 and there are insufficient data points to calculate two, four or five year betas.

The evidence also shows that betas for oil and gas companies which have substantial producing assets are generally lower than the betas for exploration and development companies. This makes sense intuitively as it indicates that producing companies are less risky than exploration and development companies, which are exposed to additional risks (although beta, as a measure of systematic risk only, should not incorporate adjustments for specific risks such as development risk).

In relation to the observed beta estimates for companies with producing assets, the Bloomberg MSCI betas for ASX listed and international companies with producing assets are broadly in the 1.1-1.4 range.

Taking all of these factors into account, Grant Samuel believes that a beta in the range 1.2-1.3 is a reasonable estimate of the appropriate beta for Cue Energy's oil and gas assets.

Calculation

Using the estimates set out above, the cost of equity capital can be calculated as follows:

Low			**High**		
Re	=	*Rf + Beta (Rm-Rf)*	*Re*	=	*Rf + Beta (Rm-Rf)*
	=	*2.1% + (1.2 x 6.0%)*		=	*2.1% + (1.3 x 6.0%)*
	=	***9.3%***		**=**	***9.9%***

3.2 Cost of Debt

A cost of debt of 4.0 % has been adopted based on a margin of 2.8% over the risk free rate. This figure represents the expected future cost of borrowing over the duration of the cash flow model. Grant Samuel believes that this would be a reasonable estimate of an average interest rate, including a margin, that would match the duration of the cash flows assuming that the operations were funded with a mixture of short term and long term debt.

3.3 Debt/Equity Mix

The selection of the appropriate debt/equity ratio involves perhaps the most subjectivity of discount rate selection analysis. In determining an appropriate debt/equity mix, regard was had to gearing levels of Cue Energy and the peer group companies used in the beta analysis.

Gearing levels for these companies for the past four years are set out below:

Gearing Levels for Selected Listed Upstream Oil and Gas Companies						
	Net Debt/(Net Debt + Market Capitalisation)					
	Financial Year Ended				Current[12]	*4 Year Average*
	Historical 4	Historical 3	Historical 2	Historical 1		
Cue Energy	**(35.0%)**	**(36.7%)**	**(327.5%)**	**(102.1%)**	**(182.1%)**	**(125.3%)**
Australia						
Production, Exploration and Development						
AWE	(25.0%)	(4.5%)	5.4%	(4.7%)	(3.3%)	(7.2%)
Drillsearch	(71.9%)	(15.6%)	18.9%	(4.0%)	0.3%	(18.2%)
Senex Energy	(18.3%)	(20.4%)	(23.2%)	(10.6%)	(22.9%)	(18.1%)
New Zealand Oil & Gas	(35.3%)	(94.7%)	(83.0%)	(68.4%)	(24.2%)	(70.3%)
Horizon Oil	1.4%	20.8%	35.7%	19.8%	52.3%	19.4%
Cooper Energy	(97.1%)	(68.1%)	(53.8%)	(39.6%)	(82.5%)	(64.6%)
Exploration and Development						
Karoon Gas	(29.9%)	(34.3%)	(22.2%)	(5.2%)	nmf[13]	(22.9%)
Tap Oil	(97.8%)	(132.9%)	(177.1%)	(55.3%)	41.2%	(115.7%)
Kina Petroleum[14]	na	(53.3%)	(22.7%)	(7.5%)	(33.2%)	(27.8%)
International						
Production, Exploration and Development						
Loyz Energy	na	na	19.7%	7.4%	56.3%	13.5%
KrisEnergy	na	na	na	(14.1%)	23.0%	(14.1%)
RH Petrogas	16.1%	25.2%	4.9%	(1.5%)	2.5%	11.2%
PT Energi Mega	36.1%	45.5%	66.6%	67.2%	56.9%	53.9%
Exploration and Development						
Rex International	na	na	na	(21.1%)	(40.0%)	(21.1%)

Source: Company Reports, IRESS, S&P Capital IQ, Bloomberg, Grant Samuel analysis

The selection of gearing levels is highly judgemental. The table shows that most upstream oil and gas companies are not geared, with the exception generally being those with producing assets and then generally at relatively modest levels. Furthermore, debt levels should be the weighted average measured over the same period as the beta factor rather than just at the current point in time. However, gearing levels do not always bear any relationship to the betas of the individual companies. In some cases lowly geared companies still have equity betas towards the higher end of the range (e.g. Karoon Gas has no borrowings but its beta is at the high end of the range). Moreover, the companies that are most comparable to Cue Energy (i.e. with producing as well as exploration and development assets) have either no or low levels of gearing.

Having regard to the above, the debt/equity mix has been estimated as 80-90% equity and 10-20% debt. This is regarded as being broadly consistent with a beta factor of 1.2-1.3.

12 Current gearing levels are based on the most recent balance sheet information and on sharemarket prices as at 28 May 2014.

13 Karoon Gas had net cash balance of A$680 million as at 31 December 2014. The current market capitalisation is below the cash holding and multiples based on current enterprise value are therefore not meaningful.

14 Kina was listed in December 2011, KrisEnergy was listed in July 2013 and Rex International was listed in July 2013.

3.4 WACC

On the basis of the parameters outlined and assuming a corporate tax rate of 40%[15], the nominal WACC is calculated to be in the range 8.2-9.5%.

Low	**High**
WACC = (Re x E/V) + (Rd x (1-t) x D/V)	*WACC = (Re x E/V) + (Rd x (1-t) x D/V)*
= (9.3% x 80%) + (4.0% x 70% x 20%)	*= (9.9% x 90%) + (4.0% x 70% x 10%)*
= 7.9%	***= 9.2%***

This is an after tax discount rate to be applied to nominal ungeared after tax cash flows. However, it must be recognised that this is a calculation based on statistics of limited reliability and involving a multitude of assumptions. In this regard, these calculations are likely to understate the true cost of capital. In this context:

- anecdotal information suggests that equity investors have repriced risk since the global financial crisis in 2007 and that acquirers are pricing offers on the basis of hurdle rates above those implied by theoretical models. However, this has yet to be translated into the measures of market risk premium (at least those based on longer term historical data). In this regard, an increase in the market risk premium of 1% (i.e. from 6% to 7%) would increase the calculated WACC range to 8.9-10.3%;
- global interest rates, including long term bond rates, are at low levels by comparison with historical norms reflecting the liquidity still being pumped into many advanced economies to stimulate economic activity. Effective real interest rates remain low. Grant Samuel does not believe this position is sustainable and the risk is clearly towards a rise in bond yields. Conceptually, the interest rates used to calculate the discount rate should recognise this expectation (i.e. they should be forecast for each future period) but for practical ease market practice is that a single average rate based on the long term bond rate is generally adopted for valuation purposes. Some academics/valuation practitioners consider it to be inappropriate to add a "normal" market risk premium (e.g. 6%) to a temporarily depressed bond yield and therefore advocate that a "normalised" risk free rate should be used. On this basis, an increase in the risk free rate to (say) 4% would increase the calculated WACC range to 9.7-11.0%; and
- analysis of research reports on Cue Energy indicates that brokers are currently adopting WACCs of around 10.0%.

Having regard to these matters and the calculations set out above, Grant Samuel has selected a discount rate range of 9.5-10.5% for application in the discounted cash flow analysis.

4 Dividend Imputation

The conventional WACC formula set out above was formulated under a "classical" tax system. The CAPM model is constructed to derive returns to investors after corporate taxes but before personal taxes. Under a classical tax system, interest expense is deductible to a company but dividends are not. Investors are also taxed on dividends received. Accordingly, there is a benefit to equity investors from increased gearing.

Under Australia's dividend imputation system, domestic equity investors now receive a taxation credit (franking credit) for any tax paid by a company. The franking credit attaches to any dividends paid out by a company and the franking credit offsets personal tax. To the extent the investor can utilise the franking credit to offset personal tax, then the corporate tax is not a real impost. It is best considered as a

15 Based on effective United States corporate income tax rates. The actual tax rate will be based on the jurisdiction that the asset is located and for companies will be a blend of the tax rates of the jurisdiction in which investments are located. Nevertheless, as the assumed gearing level is relatively low (10-20%), a higher or lower assumed tax rate has minimal impact on the calculated WACC.

withholding tax for personal taxes. It can therefore be argued that the benefit of dividend imputation should be added into any analysis of value.

There is no generally accepted method of allowing for dividend imputation. In fact, there is considerable debate within the academic community as to the appropriate adjustment or even whether any adjustment is required at all. Some suggest that it is appropriate to discount pre tax cash flows, with an increase in the discount rate to “gross up” the market risk premium for the benefit of franking credits that are on average received by shareholders. On this basis, the discount rate might increase by approximately 2% but it would be applied to pre tax cash flows. However, not all of the necessary conditions for this approach exist in practice:

- not all shareholders can use franking credits. In particular, foreign investors gain no benefit from franking credits. If foreign investors are the marginal price setters in the Australian market there should be no adjustment for dividend imputation;
- not all franking credits are distributed to shareholders; and
- capital gains tax operates on a different basis to income tax. Investors with high marginal personal tax rates will prefer cash to be retained and returns to be generated by way of a capital gain.

Others have proposed a different approach involving an adjustment to the tax rate in the discount rate by a factor reflecting the effective use or value of franking credits. If the credits can be used, the tax rate is reduced towards zero. The proponents of this approach have in the past suggested a factor in the range 50-65% as representing the appropriate adjustment (gamma). Alternatively, the tax charge in the forecast cash flows can be decreased to incorporate the expected value of franking credits distributed.

There is undoubtedly merit in the proposition that dividend imputation affects value. Over time dividend imputation will become factored into the determination of discount rates by corporations and investors. In Grant Samuel’s view, however, the evidence gathered to date as to the value the market attributes to franking credits is insufficient to rely on for valuation purposes. More importantly, Grant Samuel does not believe that such adjustments are widely used by acquirers of assets at present. While acquirers are undoubtedly attracted by franking credits there is no clear evidence that they will actually pay extra for them or build it into values based on long term cash flows. The studies that measure the value attributed to franking credits are based on the immediate value of franking credits distributed and do not address the risk and other issues associated with the ability to utilise them over the longer term. Accordingly, it is Grant Samuel’s opinion, that it is not appropriate to make any adjustment.

Appendix 2

Market Evidence

The most reliable evidence as to value of a business or asset is the price at which it or a comparable business or asset has been bought or sold in an arm's length transaction. In the absence of direct market evidence of value, estimates of value are made using methodologies that infer value from other available businesses or assets (i.e. from both transactions and the sharemarket rating of listed comparable entities). For upstream oil and gas businesses or assets market evidence is typically adopted as a cross check of valuation conclusions from discounted cash flow analysis. However, the usefulness of this analysis is limited due to a range of factors such as technical differences between assets, the jurisdictions in which they are located, their stage of delineation or development, the combination of assets owned by an entity, the lack of consistent earnings and the absence of full information in the public arena.

In the case of Cue Energy's assets there is little useful valuation guidance to be derived from transaction evidence. However, Grant Samuel has considered the sharemarket ratings of selected mid cap listed upstream oil and gas companies with an Asian focus. In particular, the companies considered have been classified according to whether they have producing assets and by the location of their stockmarket listing (i.e. Australia/international) and, due to the nature of the activities of these companies, the focus of analysis has been on valuation metrics based on reserves, resources and production (as appropriate). In this context, the sharemarket ratings of the selected companies are set out below:

Sharemarket Ratings of Selected Listed Companies – Upstream Oil and Gas Industry

Company	Market Capital-isation[1] ($ millions)	Reserves and Resources (mmboe)		Multiple of Reserves and Resources ($/mmboe)		Production (mmboe)		Multiple of Production ($/mmboe)		Multiple of EBITDA[2]
		2P[3]	2P+2C[4]	2P[5]	2P+2C[6]	Historical	Forecast	Historical	Forecast	Historical
Australia										
Production, Exploration and Development										
AWE	715	91.0	167.7	7.6	4.1	5.6	4.9	123.6	142.7	3.8
Drillsearch	459	28.3	62.0	16.2	7.4	3.4	3.2	134.7	143.1	1.9
Senex Energy	397	95.9	465.6	3.4	0.7	1.4	1.4	233.1	229.8	4.1
New Zealand Oil & Gas	209[7]	9.7	na	15.9	na	1.2	1.2	127.7	130.9	3.5
Horizon Oil	169	15.1	95.0	23.5	3.7	1.4	1.5	253.4	242.9	3.5
Cooper Energy	76	2.0	37.1	11.5	0.6	0.6	0.5	39.0	43.5	1.1
Exploration and Development										
Karoon Gas[8]	676	-	88.0	nmf[9]	nmf	-	-	nmf	nmf	nmf
Tap Oil	91	6.1	50.9	25.8	3.1	-	1.6	nmf	98.5	nmf
Kina	78	-	48.0	nmf	1.2	-	-	nmf	nmf	nmf
International										
Production, Exploration and Development										
KrisEnergy	623	32.3	121.0	25.1	6.7	1.1	3.8	760.6	213.5	nmf
Loyz Energy	36	9.2	10.0	3.3	3.0	nmf	0.4	nmf	75.0	nmf
RH Petrogas	249	19.0	81.6	13.5	3.1	1.5	1.6	170.9	161.1	4.2
PT Energi Mega	433	165.5	na	6.1	na	18.0	18.4	56.5	55.4	1.7
Exploration and Development										
Rex International	429	4.6	26.1	43.1	7.6	-	-	nmf	nmf	nmf

Source: Grant Samuel analysis[10]

1 Market capitalisation based on sharemarket prices as at 20 February 2015 converted from the local currency to Australian dollars at exchange rates as at 20 February 2015.

2 EBITDA is earnings before net interest, tax, depreciation and amortisation and significant and non-recurring items.

3 2P = proven and probable reserves

4 2C = contingent resources

5 Represents gross capitalisation (that is, the sum of the market capitalisation adjusted for minorities, plus borrowings less cash and short term investments as at the latest balance date) divided by 2P reserves.

6 Represents gross capitalisation dividend by the sum of 2P reserves and 2C contingent resources.

7 On 29 January 2015, New Zealand Oil & Gas announced a capital return to shareholders through a share buyback arrangement with 1 in every 5 shares held to be bought back at NZ$0.75/share. The capital return and associated share cancellation was completed on 20 February 2015. Accordingly the shares outstanding and therefore the market capitalisation of the company have been adjusted to reflect the capital return.

8 Karoon Gas had net cash balance of A$680 million as at 31 December 2014. The current market capitalisation is below the cash holding and multiples based on current enterprise value are therefore not meaningful.

9 nmf = not meaningful

10 Grant Samuel analysis based on data obtained from IRESS, Capital IQ and company announcements.

While none of these companies is precisely comparable to Cue Energy's activities, the sharemarket data provides some framework to assess valuation parameters for these activities. However, these multiples:

- are relatively imprecise valuation metrics and are limited in that they are calculated on publicly available information; and
- are based on sharemarket prices as at 20 February 2015 and do not reflect a premium for control.

The companies listed on international exchanges and some of the Australian companies have assets in the Asia Pacific region. Of the ASX listed entities, Kina Petroleum Limited ("Kina") invests exclusively in Papua New Guinea. Other ASX listed entities (AWE Limited ("AWE"), New Zealand Oil & Gas Limited ("New Zealand Oil & Gas"), Cooper Energy Limited ("Cooper Energy"), Horizon Oil Limited ("Horizon Oil"), Karoon Gas Australia Limited ("Karoon Gas") and Tap Oil Limited ("Tap Oil") have assets in a range of jurisdictions, including Australia and the Asia Pacific region.

A brief description of each company is set out below:

AWE Limited

AWE is an ASX listed energy company focused on upstream oil and gas production, exploration and development. It has interests in producing assets in Australia, New Zealand and the United States, which it expects will produce 4.6-5.1mmboe in FY15. It also has interests in development/appraisal/ exploration assets in Australia, New Zealand, Indonesia and the United States. As at 30 June 2014, it had 91.0mmboe of 2P reserves and 76.7mmboe of 2C resources. In November 2014, AWE completed the sale of 11.25% interest in the BassGass infrastructure and Yolla field and 9.75% interest in Trefoil field for $85 million[11]. In September 2014, AWE announced the discovery of the Waitsia gas field (2C resources of 24mmboe) and in January 2015, AWE announced additional 2P reserves (1.4mmboe) at Tui fields in New Zealand. The multiples have not been adjusted for the impact of the transaction nor the additional 2P reserves and 2C resources.

Drillsearch Limited

Drillsearch Limited ("Drillsearch") is an ASX listed energy company focused on upstream oil and gas production, exploration and development in Australia's Cooper Basin. It expects to produce 3.0-3.4mmboe in FY15. As at 30 June 2014, it had 28.3mmboe of 2P reserves and 33.7mmboe of 2C resources. In October 2014, Drillsearch completed the acquisition of Ambassador Oil and Gas ("Ambassador") consolidating its holding in Northern Cooper Wet Gas area and increasing Drillsearch's exposure to unconventional oil and gas. The scrip-based transaction valued Ambassador at approximately $38 million.

Senex Energy Limited

Senex Energy Limited ("Senex") is an ASX listed energy company focused on upstream oil and gas production, exploration and development in Australia's Cooper, Eromanga and Surat Basins, as well as coal seam gas acreage in Queensland. It expects to produce in excess of 1.4mmboe in FY15. As at 30 June 2014, Senex had 39.9mmboe of 2P reserves and 369.7mmboe of 2C resources with majority of the 2C resources associated with unconventional gas. In September 2014, Senex announced an asset swap agreement with QGC JV which resulted in Senex's 2P reserves increasing to 95.9mmboe[12]. The multiples have been adjusted for the impact of the transaction.

New Zealand Oil & Gas Limited

New Zealand Oil & Gas is a dual-listed (ASX and NZX) oil and gas exploration and production company. The company's key assets are its 27.5% interest in the Tui area oil fields and its 15% interest in the Kupe fields located in the offshore Taranaki basin, New Zealand. The company is also involved in the exploration and evaluation of hydrocarbons in the offshore Taranaki basin and offshore Canterbury basin, New Zealand; and Indonesia. During FY14, New Zealand Oil & Gas produced in excess of 1.2mmboe and is forecast to produce slightly lower during FY15. As at 30 June 2014, the company had reported 9.7mmboe of 2P reserves.

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11 AWE had reported 2P reserves and 2C resources of 26mmboe and 36mmboe respectively at Bass Basin reflecting its 46.25% interest in the basin prior to the transaction.

12 Senex's Surat Basin gas reserves (2P) increased by 56mmboe from 26.6mmboe to 83mmboe.

Horizon Oil Limited

Horizon Oil Limited ("Horizon Oil") is an ASX listed oil and gas exploration and production company. Its assets include interests in the Maari/Manaia fields and Offshore Taranaki Basin property in New Zealand; Stanley condensate/gas development and the Elevala and Ketu projects in Papua New Guinea; and Block 22/12 (Beibu) in China. During FY14 Horizon Oil produced 1.4mmboe from the Maari and Beibu fields and is currently producing at an annualised rate of approximately 1.5mmboe.

Cooper Energy Limited

Cooper Energy is an ASX listed energy company focused on upstream oil and gas exploration and development. It has interests in assets which have recently commenced production in the Cooper Basin and Indonesia and interests in development/appraisal/exploration assets in the Cooper Basin, Otway Basin, Gippsland Basin and Indonesia. It is expected to produce around 0.53mmboe during FY15. As at 30 June 2014, Cooper Energy had 2.0mmboe of 2P reserves and 35.1mmboe of 2C resources.

Karoon Gas Australia Ltd

Karoon Gas is an ASX listed energy company focused on upstream oil and gas exploration and development. It does not have producing assets. It has interests in development/appraisal/exploration assets in the Browse and Carnarvon basins in Australia and in Peru and Brazil. In August 2013, Karoon Gas reported 88mmboe (net) of 2C resources. On 2 June 2014, it announced the sale of its 40% interest in Browse Basin permits WA-315-P and WA-398-P to Origin Energy for a US$600 million upfront cash payment and deferred cash payments of up to US$200 million. The transaction was completed in August 2014 and Karoon Gas received A$655 million representing the upfront payment. Karoon Gas has an active exploration and evaluation program requiring substantial capital commitment, including $116 million forecast for March 2015 quarter.

Tap Oil Limited

Tap Oil is an ASX listed energy company focused on upstream oil and gas exploration and development. It has interests in development/appraisal/exploration assets in the Carnarvon Basin and Otway Basin in Australia, Manora Oil Development in the Northern Gulf of Thailand and Myanmar. The company commenced production from Manora Oil Development in Thailand in November 2014 and is targeting peak production of 4,500bbl/d (net to Tap Oil) during the first quarter of CY15. As at 31 December 2013, Tap Oil had 6.1mmboe of 2P reserves and 44.8mmboe of 2C[13] resources.

Kina Petroleum Limited

Kina is an energy company focused on upstream oil and gas exploration and development in Papua New Guinea. It was listed on the ASX in December 2011. Kina does not currently have producing assets. Kina has interests in seven onshore Petroleum Prospecting Licences and a 15% interest in PRL 21, which contains two wet gas discoveries, Elevala and Ketu, and Tingu. Initially awarded 20% of PRL 21, Kina divested 5% of PRL21 in 2011 for US$5.5 million. Kina also has 25% interest in PRL38 which contains two gas discoveries. As at 31 December 2014, Kina had a total of 48.0mmboe (net to Kina) of 2C resources within PRL 21 (Elevala and Ketu) and PRL38 (Pandora).

KrisEnergy Limited

KrisEnergy Limited ("KrisEnergy") is an energy company focused predominantly on upstream oil and gas production, exploration and development. It was listed on the Singapore Exchange in July 2013. It has an extensive portfolio of licences throughout Asia, including in Bangladesh, Cambodia, Indonesia, Thailand and Vietnam. As at 31 December 2013, it reported 32.3mmboe of 2P reserves and 88.7mmboe of 2C resources. KrisEnergy is currently producing at an annualised rate of 3.8mmboe significantly higher than the 1.1mmboe produced during CY2013.

RH Petrogas Limited

[13] Tap Oil's 2C resources include 220PJ of natural gas

RH Petrogas Limited ("RH Petrogas") is a Singapore Exchange listed energy company focused on upstream oil and gas production, exploration and development. It has interests in assets primarily in Indonesia as well as in China and Malaysia. In the 12 months to 31 December 2013, it produced 1.5mmboe of oil and gas and is currently producing at an annualised rate of 1.6mmboe. As at 31 December 2013, RH Petrogas had 19.0mmboe of 2P reserves and 62.6mmboe of 2C resources.

Loyz Eenergy Limited

Loyz Energy Limited ("Loyz Energy") is an energy company listed on the Singapore Exchange Catalist Market. The company focuses on the exploration, development, and production of oil and gas in the Asia-Pacific region. The company acquired 20% stake in producing concessions in Thailand in April 2014. It also owns two petroleum exploration permits, one in the prolific Taranaki basin offshore New Zealand and the other in in Torquay sub-basin in Australia. As at 30 June 2014, Loyz Energy had net 2P reserves of 9.2mmboe and 2C resources of 0.8mmboe. The company is currently producing at an annualised rate of 0.4mmboe (net to Loyz Energy).

PT Energi Mega Persada Tbk

PT Energi Mega Persada Tbk ("Energi Mega Persada") is a Jakarta Stock Exchange listed energy company focused on upstream oil and gas production, exploration and development throughout Indonesia (including Kangean Island, East Java province, Riau, Jambi, North Sumatra, East Kalimantan and West Java). It operates oil, gas and coal bed methane assets and as at 30 September 2014 the company reported 2P reserves of 165mmboe. In the year to 31 December 2013, Energi Mega Persada produced 18.0mmboe of oil and gas and is currently producing at an annualised rate of 18.4mmboe.

Rex International Holding Limited

Rex International Holding Limited ("Rex") is an energy company focused on upstream oil and gas exploration and development. It was listed on the Singapore Exchange Catalist Market in July 2013. It has an extensive portfolio of licences across several continents and has a proprietary technology that it believes to enable it to prove up reserves and resources more rapidly than its competitors. As at 31 December 2013, Rex reported 4.6mmboe of 2P reserves and 21.5mmboe of 2C resources. Rex does not currently have producing assets. Its relatively high multiples may reflect its proprietary technology and rapid growth expectations.

Appendix 3

Report by RISC Operations Pty Ltd

Independent Technical Specialist Report

Cue Energy Resources Limited

February 2015

decisions with confidence

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The Directors
Cue Energy Resources Limited
Level 19, 357 Collins Street
Melbourne VIC 3000

Mr Stephen Cooper
Grant Samuel & Associates
Level 6, 1 Collins Street
Melbourne VIC 3000

Dear Sirs and Madam,

Independent Specialist's Report on Cue Energy's Petroleum Assets

1. Introduction

Grant Samuel & Associates Pty Ltd ("Grant Samuel") has been appointed by Cue Energy Resources Limited ("Cue") to prepare an independent expert's report in relation to the on market takeover offer from New Zealand Oil & Gas Limited under which its' wholly owned subsidiary, NZOG Offshore Limited, will acquire all the shares in Cue.

To assist Grant Samuel in preparing its independent expert's report of the takeover offer, Cue engaged RISC Operations Pty Ltd ("RISC") to act as an independent specialist, as defined in the Code for Technical Assessment and Valuation of Mineral and Petroleum Assets and Securities for Independent Expert Reports, as amended (the VALMIN Code), and to prepare an Independent Technical Specialist Report (ITSR).

RISC's role in this engagement is to prepare or, if already available, review estimates of reserves and resources, capital costs, production profiles and operating costs for the producing and development operations of Cue, advise Grant Samuel as to whether these assumptions are reasonable for valuation purposes, prepare sensitivities that may need to be carried out and prepare a report. In addition, the report will need to set out RISC's estimates of value for Cue's exploration interests.

Cue has made available to RISC a data set of technical information including geological, geophysical, petrophysical, engineering, production and operational data and reports. RISC has also had meetings and discussions with Cue's technical and management personnel. In carrying out this review, RISC has relied on the information received from Cue and information in the public domain.

To assess reserves and resources, RISC has used the Petroleum Resources Management System published by the Society of Petroleum Engineers / World Petroleum Council / American Association of Petroleum Geologists / Society of Petroleum Evaluation Engineers (SPE/WPC/AAPG/APEE) in March 2007 (SPE PRMS).

This document comprises the ITSR. It documents our review of Cue's petroleum reserves, resources and associated development schedules, production and cost forecasts. We have reviewed the estimates provided by Cue and made such adjustments that in our judgment were necessary to provide a reasonable assessment and reflect current information. This report also provides an opinion on the value of Cue's exploration assets.

2. Summary

2.1. Overview

The document comprises the Independent Technical Specialists Report by RISC Operations Pty Ltd ("RISC") to assist the Independent Expert, Grant Samuel & Associates Pty Limited ("Grant Samuel") in the preparation of an Independent Expert's Report to the Directors of Cue Energy Resources Limited ("Cue") on the proposed takeover offer from NZOG Offshore Limited, the wholly owned subsidiary of New Zealand Oil & Gas Limited. The locations of Cue's petroleum properties are shown in Figure 2-1.

The report documents our review of the petroleum reserves, resources and associated development schedules, production and cost forecasts (projects) provided by Cue to the Independent Expert, which have been used to value the oil and gas properties. We have also addressed the risks associated with the projects. We have reviewed the estimates provided by Cue and made such adjustments that in our judgment were necessary to provide a reasonable assessment and reflect current information.

This report also provides an opinion on the fair market value of the exploration properties of Cue.

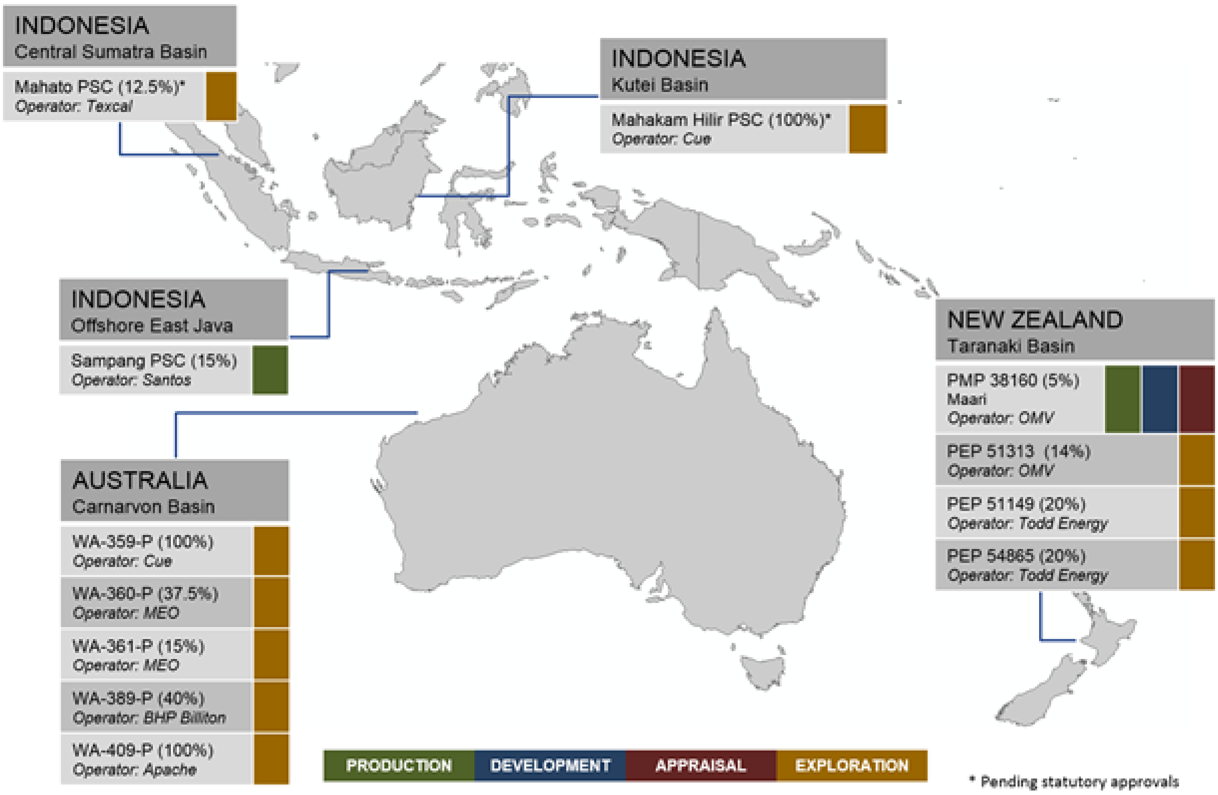


Figure 2-1: Cue Energy Resource Limited's petroleum asset portfolio

For valuation purposes, we have prepared 2 production scenarios for the Indonesian assets and 3 scenarios for Maari. These scenarios are summarized in Table 2-1 and Table 2-2.

Details of these scenarios along with costs and production profiles associated with the development and production of these resources are included in our report. Remaining production and costs are at an effective date of 1 January 2015 and are provided through to end 2040 for the Maari Project and end 2020 for the Sampang PSC. Production is subject to application of an economic cut-off by Grant Samuel. Note that in the Sampang PSC, resource entitlement is determined by the PSC terms which define cost and profit oil and gas which are a function of future costs and prices and may not be the same as the working interest. Production is rounded to the nearest 0.1 MMbbl and 0.1 bcf. Costs are rounded to the nearest $0.1 million.

Table 2-1: Maari Valuation Scenario Summary

Maari Project (Cue 5%)	Scenario 1: 2P Case	Scenario 2: 2P Sensitivity	Downside Case: 1P
Description	Best estimate reservoir performance Growth Project delivers 4 production wells	Best estimate reservoir performance excluding benefit from water injection Growth Project delivers 4 production wells	Conservative reservoir performance Growth Project delivers 4 production wells
Remaining Production MMstb net WI	2.1	1.8	1.2
Net WI Capex US$ MM	18.1	18.1	18.0

Table 2-2: Sampang PSC Valuation Scenario Summary

Sampang PSC: (Cue 15%)	Scenario 1: 1P Case	Scenario 2: 2P Case
Description	Conservative reservoir performance	Best estimate Reservoir Performance
Remaining Gas Production MMstb net WI	11.1	14.7
Remaining Oil / Cond Production MMstb net WI	0.3	0.4
Net WI Capex US$ MM	0.3	0.3

2.2. Exploration valuation

RISC has assessed the value of Cue's individual exploration interests using the value of the work program and farm-in promote multiples. The sum of our low, mid and high estimates of the value of the individual permits, net of future firm commitment expenditures, are summarised in Table 2-3 below.

Table 2-3: Exploration Valuation - Cue Energy's net working interest

Area	**Fair Market Value, A$ million**		
	Low	**Mid**	**High**
New Zealand	1.9	2.9	6.9
Indonesia	5.3	10.9	20.7
Australia	0.0	0.0	9.9
Total	**7.2**	**13.8**	**37.5**

The aggregated mid-value of each of the exploration assets has been assessed at A$ 13.8 million, while the low and high value estimates are A$ 7.2 million and A$ 37.5 million, respectively.

As the low and high values of the exploration assets portfolio have been derived by the arithmetic addition of the individual asset low and high values, respectively, they represent the possible extremes of the exploration value envelop. While farmees into the individual permits could value the assets at either end of the value range assessed, it is unlikely that potential buyers of the exploration asset portfolio would value all of the assets at either all of the low or all of the high estimated extremes. Their own assessments of individual permits will span the low, mid or high outcomes based on factors including: their strategic objectives and region or geological basin focus; assessment of an asset’s prospectivity and associated geological risks; the fiscal and regulatory framework applicable to the asset; accessibility of commercialisation routes, including markets and infrastructure, for each asset; equity interests, operator capability and joint venture partners in each asset.

Consequently, RISC assesses the value of Cue’s exploration asset portfolio to a single buyer as lying between A$10 million and A$20 million.

3. Terms of reference

Grant Samuel has requested that RISC to carry out the following scope of work:

To review for reasonableness the cost and production assumptions to be used in the valuation of Cue's petroleum assets by:

- Preparing, or if already available, reviewing for the production and development operations of Cue, estimates of:
    - Reserves and resources
    - Production profiles
    - Capital costs
    - Operating costs

  under a number of development/production scenarios advised by Grant Samuel.

- Reviewing Cue's exploration assets and preparing a valuation of those interests.

4. Basis of assessment

The data and information used in the preparation of this report were provided by Cue and supplemented by public domain information. RISC has relied upon the information provided and has undertaken the evaluation on the basis of a review of existing interpretations and assessments as supplied, making adjustments that in our judgment were necessary.

RISC has reviewed the reserves/resources in accordance with the Society of Petroleum Engineers internationally recognised Petroleum Resources Management System (SPE-PRMS)[1].

RISC has also been requested to provide an opinion on the fair market value of the exploration properties. We have carried out our valuation in accordance with the VALMIN code[2].

Unless otherwise stated, all costs and values are in gross US$ real terms with a reference date of 1 January 2015. Production is reported in gross terms unless otherwise stated with a reference date of 1 January 2015.

4.1. Valuation

The valuation is based on the concept of 'fair market value' (Value) as defined by the VALMIN Code.

The VALMIN Code defines Value as the amount of money (or the cash equivalent of some other consideration) determined by the Expert in accordance with the provisions of the VALMIN Code for which the Mineral or Petroleum Asset or Security should change hands on the Valuation Date in an open and unrestricted market between a willing buyer and a willing seller in an "arm's length" transaction, with each party acting knowledgeably, prudently and without compulsion.

A range of oil and gas industry accepted practices in relation to petroleum properties has been considered to determine value, which are described below.

4.1.1. Comparable Transaction Metrics

The Value of exploration properties can be estimated using recent comparable transactions. Such transactions may provide relevant metrics such as Value per unit of reserves, contingent or prospective resources, price paid per unit area of the permit or % interest. The VALMIN Code advises Value must also take into account risk and premium or discount relating to market, strategic or other considerations.

4.1.2. Farm-in Promotion Factors

An estimate of Value can be based on an estimation of the share of future costs likely to be borne by a reasonable farmee under prevailing market conditions. A premium or promotion factor may be paid by the farmee. The promotion factor is defined as the ratio of the proportion of the activity being paid for and the amount of equity being earned.

The nominal permit value is defined as the amount spent by the farmee divided by the interest earned. The premium value for the permit is the difference between the nominal value and the equity share of the cost of the activity divided by the equity interest being earned.

The premium or promotion factor will be dependent upon the perceived prospectivity of the property, competition and general market conditions. The premium value is equivalent to the farmee paying the farmor a cash amount in return for the acquisition of the interest in the permit and is the fair market value.

[1] SPE/WPC/AAPG/SPEE 2007 Petroleum Resources Management System

[2] Code for the Technical Assessment and Valuation of Mineral and Petroleum Assets and Securities for Independent Expert Reports 2005 Edition

Farm-in transactions may have several stages. For example, a farmee may acquire an initial interest by committing to a future cost in the first stage of the transaction, but has an option to acquire an additional interest or interests in return to committing to funding a further work programme or programmes.

Farm-in agreements can also include re-imbursement of past costs and bonus payments once certain milestones are achieved, for example declaration of commerciality, or achieving threshold reserves volumes. Depending on their conditionality, such future payments may contribute to Value. However, they may need to be adjusted for the time value of money and probability of occurring.

4.1.3. Work Programme

The costs of a future work program may also be used to estimate Value. The work program valuation relies on the assumption that unless there is evidence to the contrary the permit is worth what a company will spend on it. This method is relevant for permits in the early stages of exploration and for expenditure which is firmly committed as part of a venture budget or as agreed with the government as a condition of holding the permit. There may need to be an adjustment for risk and the time value of money.

4.1.4. Expected Monetary Value (EMV)

EMV is the risked NPV of a prospect. EMV is calculated as the success case NPV times the probability of success less the NPV of failure multiplied by the probability of failure. The NPV may be estimated using DCF methods. The EMV method provides a more representative estimate of Value in areas with a statistically significant number of mature prospects within proven commercial hydrocarbon provinces where the chance of success and volumes can be assessed with a reasonable degree of predictability.

The EMV valuation can also be used as a relative measure for ranking exploration prospects within a portfolio to make drilling decisions, assessing commercial potential and to demonstrate the commercial attractiveness of a permit, which may influence a buyer or seller.

5. New Zealand

5.1. PMP 38160 (Maari) - Cue 5%

5.1.1. Geological Setting

Cue's offshore and onshore New Zealand permits are located within the Taranaki Basin. The Taranaki Basin is a Late Cretaceous-Cainozoic basin located on the western side of the New Zealand subcontinent. The basin covers and has area of approximately 100,000 km2 and is highly varied both structurally and stratigraphically. It is divided into two broad N-S striking structural elements called the Western Stable Platform and Eastern Mobile Belt. The Western Platform over which Cue's offshore permits are located is a 150 km wide shelf that underlies the middle and outer parts of the present day continental shelf to the west. This area is characterised by layer cake and progradational sedimentation on an unfaulted, sub-horizontal, regionally subsiding sea floor. The Eastern Mobile Belt is an 80 km wide depression located on the eastern side of the basin. It is highly faulted and folded and contains up to 11,000 m of sediments.

The Miocene and Eocene aged sediments highlighted in Figure 5 10 are the primary reservoirs within Cue's permits.

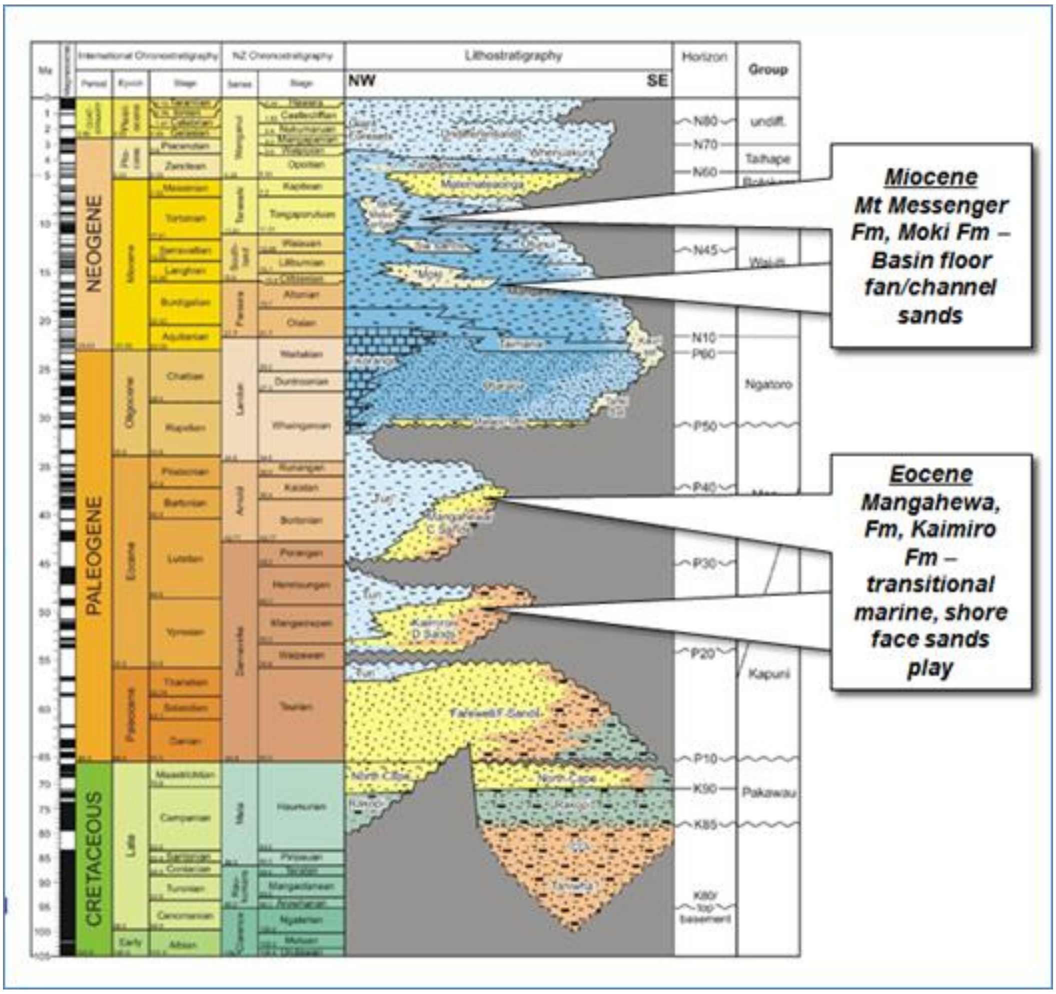


Figure 5-1 Taranaki Basin stratigraphic column

The Maari and Manaia fields are located in PMP 38160 offshore New Zealand (shown in Figure 5-2), in which Cue Energy holds a 5% interest.

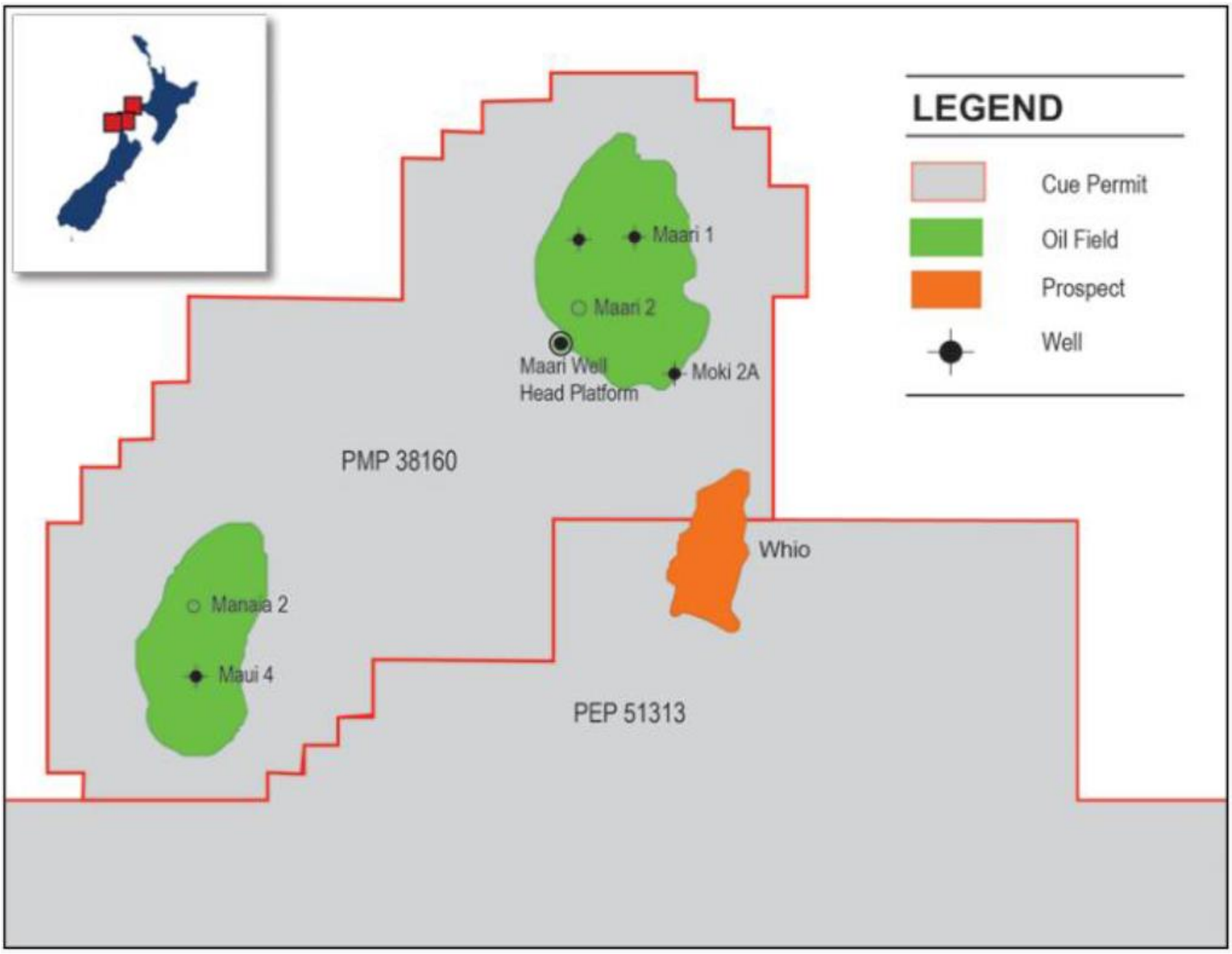


Figure 5-2: Maari and Manaia Field Location

A structural section showing the location of significant reservoirs is shown in Figure 5-3. Both the Maari and Manaia structures are noted to be large, but substantially underfilled. Note the Whio prospect shown was drilled in 2014 and was dry.

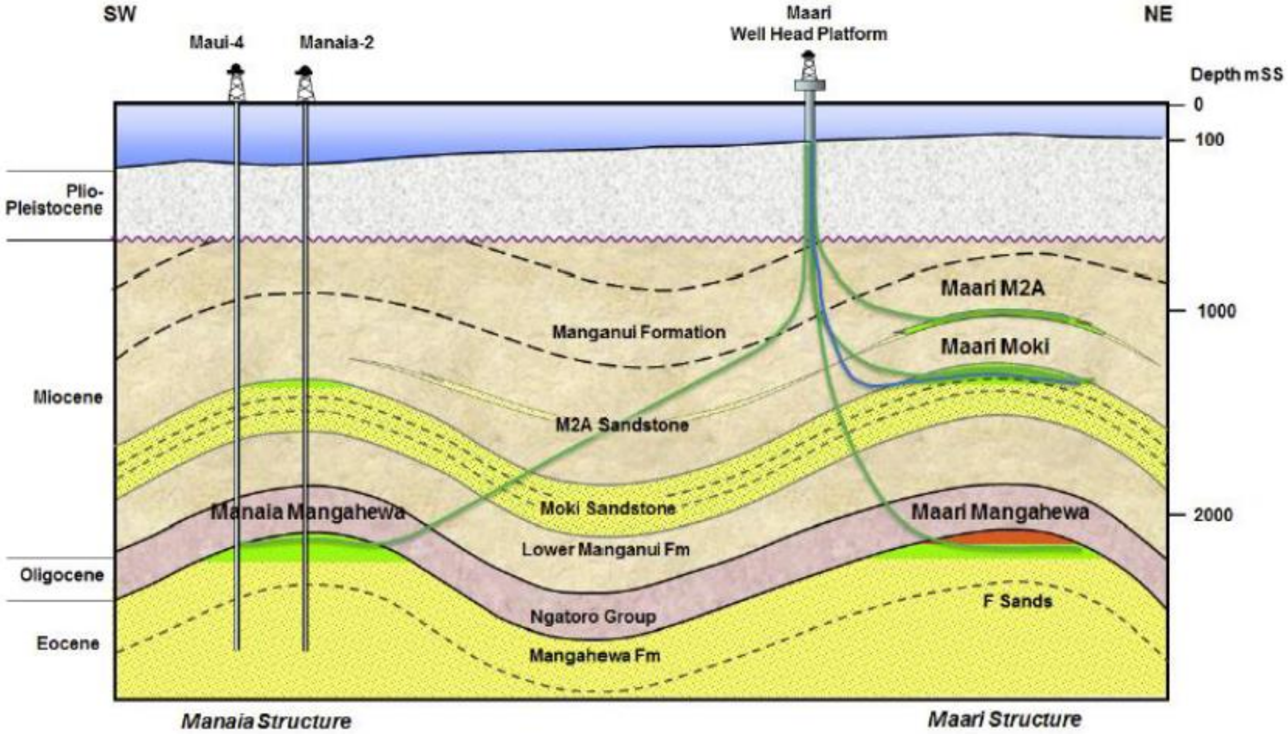


Figure 5-3: Maari Manaia Structural Section

The Maari Field produces from the Moki and M2A sands, which were deposited as turbidites in the Miocene downwarping of the Taranaki Basin. Further oil is reservoired in the deeper Mangahewa Formation of the Kapuni Group, which was deposited in the post-rift thermal sag phase in the Eocene, which has been producing from the Maari field.

A deviated well from the Maari platform has been drilled to the Mangahewa Formation of the Manaia field and is currently producing. In addition, the Mania-2/2A well was drilled in 2013 and proved the Moki reservoir oil bearing.

5.1.2. Development Description

The Maari Development involves a not-normally manned wellhead platform housing the wellheads of both production and water injection wells producing from the Maari and Manaia fields, linked via subsea flowlines to the floating production, storage and offloading vessel (FPSO) Raroa, moored 1.5 km away in a water depth of approximately 100m. Production wells are lifted with downhole Electrical Submersible Pumps (ESPs). Because the ESP's need regular replacement, a workover rig is kept on the platform. Water is injected with the aim of maintaining reservoir pressure. The fields are operated by OMV New Zealand Limited (OMV). Production commenced in February 2009 and averaged 7200 stb/d in January 2015 from 5 production wells (MR3 was shut-in in early January 2015). As at 31 December 2014, the project has produced 25.2 MMstb of oil. A further 0.3 MMbbl was produced up to 9 February 2015 which is the latest date of production information provided.

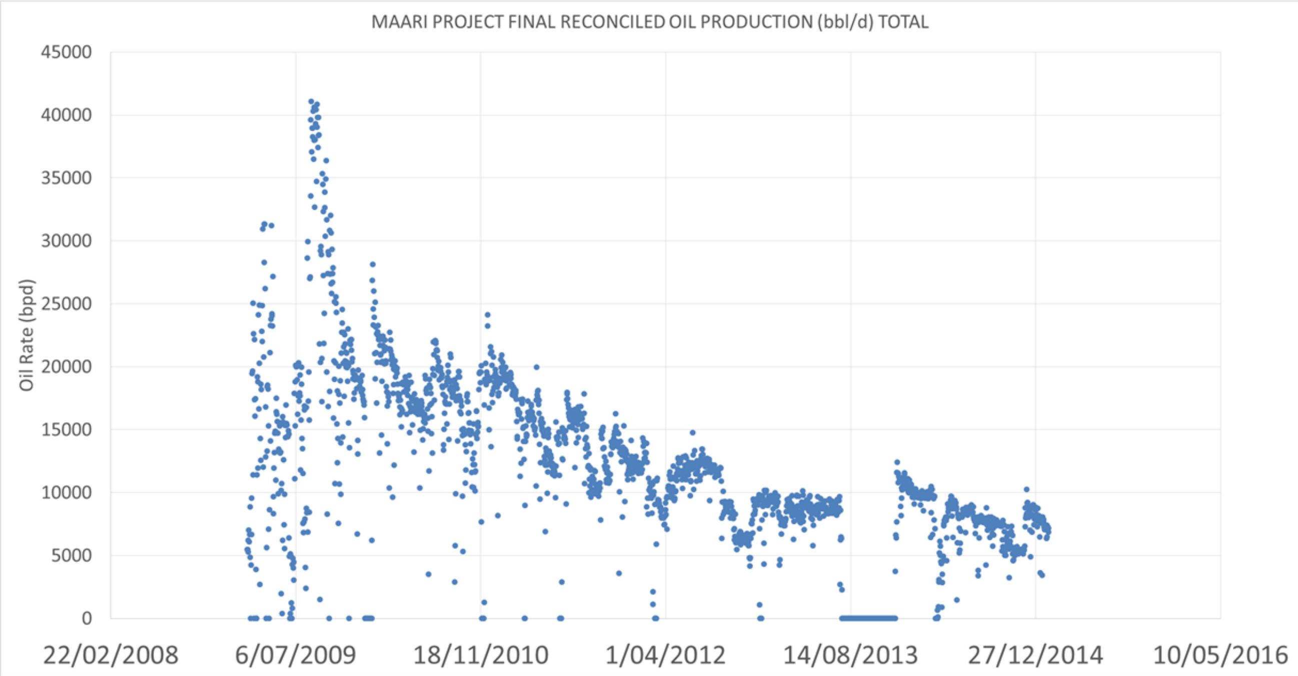


Figure 5-4 Maari Production History

Developed Production Forecast

The status of the Maari production wells and cumulative production is shown in Table 5-1.

Table 5-1 Maari Well Status

Well	Reservoir	Cumulative Production to 31 Dec 2014 MMstb	Status
MR1A	Moki	1.9	Water injector
MR2	Moki	5.1	Producing
MR3	Moki	4.8	Shut in awaiting ESP replacement and stimulation est. Dec 2015
MR4	Moki	5.6	Producing
MR5	Moki	4.0	Producing
MR7	Moki	0	Abandoned water injector, slot reclaimed for MR7A production well.
MR8A	Moki	0.1	Producing
MR9	M2A	1.3	Shut in awaiting ESP replacement est Nov 2015
MN-1	Manaia Mangahewa	2.4	Producing
Total		25.2	

RISC has evaluated the production performance of the existing producers using decline curve analysis. Our analysis shows that the performance is generally hyperbolic tending towards harmonic. Due to the intermittent nature of production from individual wells and the operational influences associated with ESP performance, the data contains a lot of noise which increases the uncertainty in well analysis.

The decline curve behaviour is consistent with the reservoir architecture, limited connectivity and some pressure support which we believe is coming from the underlying aquifer. We note Cue's opinion that the Lower Moki in particular is likely to be subject to aquifer support and that there is no strong evidence that the reservoir has responded positively to water injection. A total of 39.6 MMbbl of water has been injected and 4.8 MMbbl produced. Most of the water injection appears to have been displaced out of zone.

In the case of the MR8A well, where sufficient production was not available to carry out a decline analysis, we have estimated the performance based on the anticipated pre-drill performance adjusted for actual post drill results in which the Lower Moki completion interval was substantially curtailed.

The range of future production used in the valuation based on decline curve analysis of the existing wells taking into account the proposed recompletion activities of the MR3 and MR9 wells is shown in Figure 5-5 (The MR8A recompletion is included in undeveloped production).

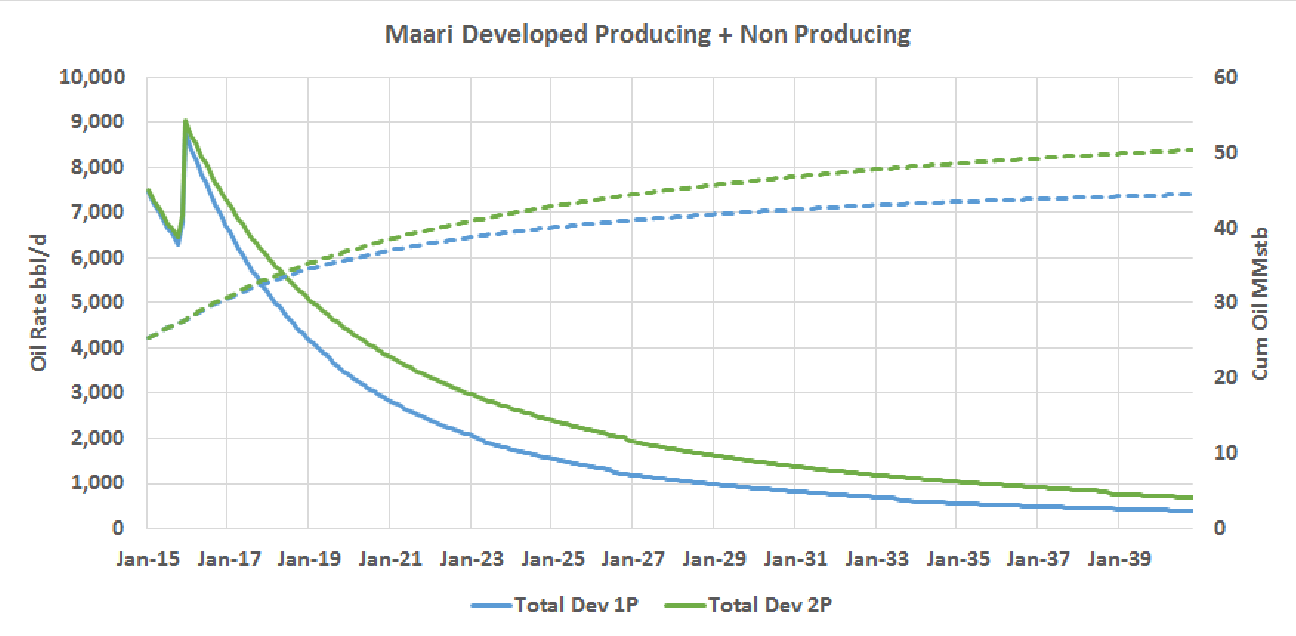


Figure 5-5 Maari Developed Production Forecast

Development Projects

Following a refurbishment of the FPSO mooring and turret system in 2013, in April 2014, the Maari Growth project commenced. This project originally comprised:

- drilling of 2 new producers and 1 new injector in the Maari Moki reservoir and the conversion of 1 producer to a water injector
- drilling of 1 new producer in the Maari Mangahewa reservoir
- drilling of 1 new extended reach producer in the Manaia Mangahewa reservoir

The Maari Growth project anticipated increasing production to 20,000 stb/d gross by end 2014. It also aimed to remedy problems with the water injection scheme, which has not generated the expected benefits and resulted in a reserves downgrade in 2013.

However the project has experienced operational difficulties resulting in delays, production deferral and cost overruns. The original schedule had project completion by the end 2014 and it is currently schedule for mid-2015. The budget at sanction was US$289 million and the estimated final cost at December 2014 was US$387 million. Since commencing the project in May 2014, only one of a scheduled 4 production wells have been completed. The MR8A well is now online and experiencing lower performance than expected as the well has been completed in shorter than expected reservoir section. As a result the JV has adjusted its activity plan compared to both FID and the 2015 Budget. Based on a Technical Committee Meeting (TCM) held 20 February 2015, Cue advised that the following activities reflect current decisions regarding the revised Maari Growth Project plans:

- MR8A was drilled, completed and came on line in November 2014. There is additional behind pipe pay in the well which will be the subject of a workover to access it later in 2015.
- MR6A – planned reparation and completion after significant losses during 2014.This well is currently drilling. The well is estimated to be online in March 2015 producing from the Maari Mangahewa reservoir.
- An option is being considered for MR10 Upper Moki Eastern Flank is for it to be drilled initially as a producer and converted into a water injector after at least 2 years of production. We estimate that this well will be completed and online in Q2 2015. This would represent a change from the original plan for the well which was as a dedicated water injector.
- Sidetrack of currently suspended MR7A well into the Upper Moki as a producer. The new well plans to be completed and online in Q3 2015.
- There are also 3 workovers scheduled for the second half of 2015 to replace ESP's, access behind pipe pay and carry out stimulation on the MR3 damaged by drilling fluid influx. These wells are MR9, MR8A and MR3.
- The JV is currently considering whether to include an additional infill well in the program to match the 4 producers and 1 injector approved at project sanction. A decision has not been made on this well and we have not included it in the forecasts.

Valuation Scenarios

The following scenarios have been provided for valuation purposes:

- **Scenario 1:** Execute the current work program, best estimate (2P) reservoir performance, RISC estimated benefit from water injection
- **Scenario 2:** Execute the current work program, best estimate (2P) reservoir performance, no benefit from water injection
- **Downside Scenario:** Execute the current work program, conservative (1P) reservoir performance, no benefit from water injection

Forward drilling costs are based on the opinion that the operator will more likely than not benefit from a significant drilling learning curve and that future well outcomes are more likely to align with current cost and schedule plans. That said, the risk of past drilling issues manifesting in future wells is possible, resulting in significant cost growth and schedule slip. In Scenario 1 and 2 we include minor capital works in 2017 for the conversion of the Eastern Flank Producer into a water injector.

The ENSCO 107 rig is scheduled to end its current contract early June 2015, with the option for a 30 day extension under the same contract terms should critical works be required. A new contract will need to be negotiated should the rig be required past this term. We understand that the term of the rig contract will not influence the operator's ability to execute the planned work program. We have been advised by Cue that equipment is currently in stock for all planned wells.

All scenarios include developed production from existing wells and the benefit of the planned workovers. A summary of each scenario is shown in the table below. Activities are consistent across scenarios, with differences driven by uncertainties in reservoir performance.

	Downside Scenario: 1P	**Scenario 1: 2P case**	**Scenario 2: 2P Sensitivity**	**All Scenarios**	
Activity	**EUR (MMstb)**	**EUR (MMstb)**	**EUR (MMstb)**	**First Oil**	**Forward Capex (MMUS$)**
MR6A Maari Manhahewa Producer	1.8	3.9	3.9	Apr-2015	29.1
Maari Upper Moki Eastern Flank Producer	0.6	0.8	0.8	Jun-2015	35.6
Maari Upper Moki Eastern Flank Injector (Conversion)[1]	0	9.4	0	Jun-2017	2.0
Mari Upper Moki Producer (from MR7A wellbore)	1.2	2.6	2.6	Aug-2015	36.0
MR8A Cycle 1 Recompletion	1.0	3.2	3.2	Oct-2015	2.5
Total Undeveloped	4.6	19.9	10.5		103.2 to 105.2

1. Cost and activity only relevant to Scenario 1 and 2
2. M8A is carrying remaining $4.3m capex in 2015

Table 5-2 Maari Valuation Scenarios Development Project Summary

The well recompletion and intervention activities occur once the rig moves offsite mid-2015. The undeveloped production forecasts for each scenario are shown in Figure 5-6.

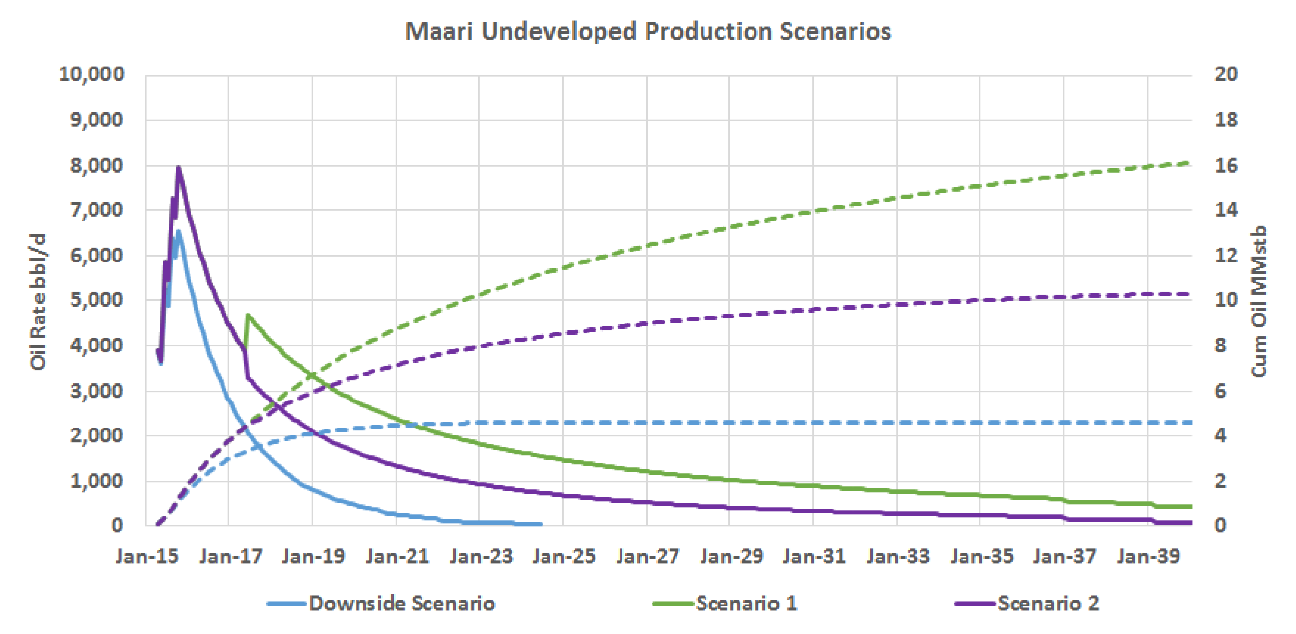


Figure 5-6 Maari Undeveloped Production Forecast

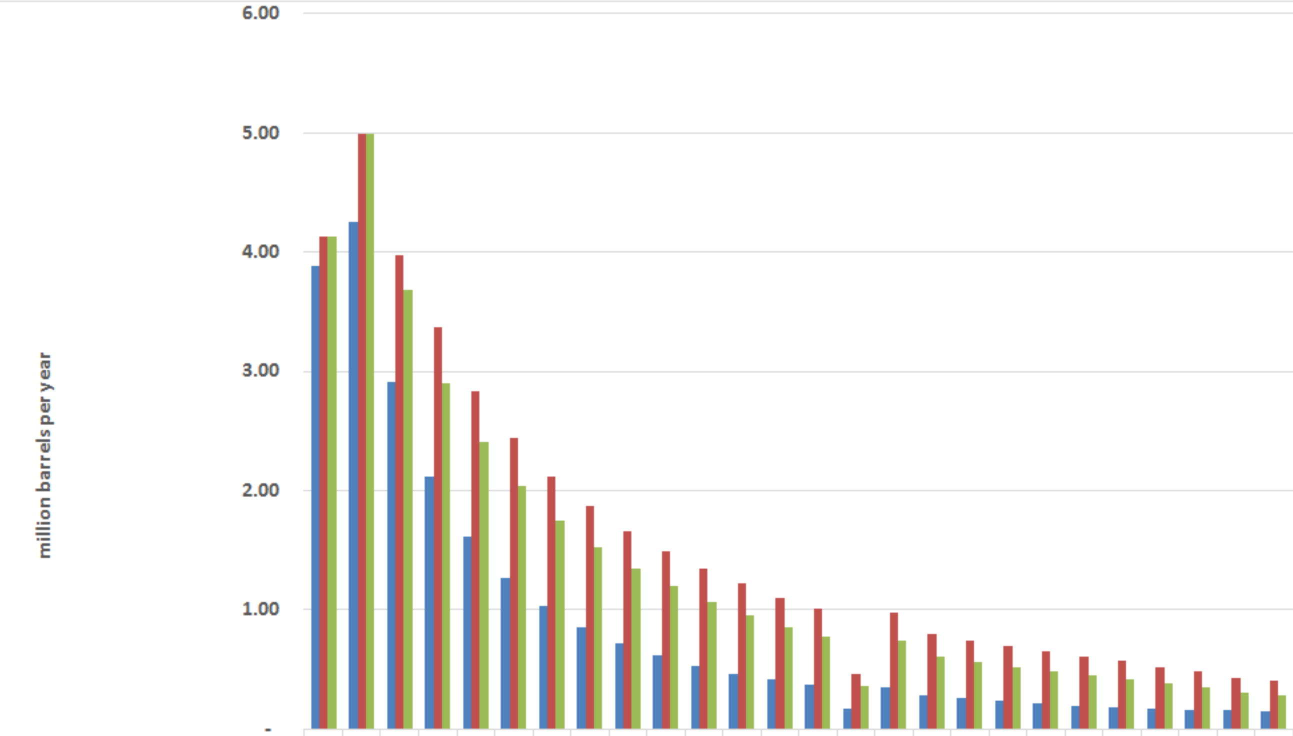
The costs for the MR8A, MR3 and MR9 workovers are included in the 2015 workover program budget at $8 million which in our opinion is sufficient.

A scenario was evaluated whereby four wells were drilled to develop contingent resources in the Maari Lower Moki, Manaia Moki, Maari M2A (water injector) and MN3 Mania Mangahewa. Our view is that these projects are likely to be marginal in the current oil price environment and have not included them in our valuation scenarios.

We also recognise that there is the potential for upside performance in the reservoir. However after discussions with the independent expert we have not prepared upside scenarios for valuation as this will carry a relatively low weighting.

Production Forecasts

Figure 5-7 shows the total developed plus undeveloped production forecast for each scenario. Production adjustments have been made to reflect the potential impact from ENSCO 107 removal/shutdown, FPSO topside upgrades, FPSO mooring line repairs, and major FPSO and WHP life extension.



	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
Downside Scenario Production	3.8	4.2	2.9	2.1	1.6	1.2	1.0	0.8	0.7	0.6	0.5	0.4	0.4	0.3	0.1	0.3	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1
Scenario 1 Production	4.1	4.9	3.9	3.3	2.8	2.4	2.1	1.8	1.6	1.4	1.3	1.2	1.1	1.0	0.4	0.9	0.8	0.7	0.6	0.6	0.6	0.5	0.5	0.4	0.4	0.4
Scenario 2 Production	4.1	4.9	3.6	2.9	2.4	2.0	1.7	1.5	1.3	1.2	1.0	0.9	0.8	0.7	0.3	0.7	0.6	0.5	0.5	0.4	0.4	0.4	0.3	0.3	0.3	0.2

Figure 5-7 Maari Production Forecast

From 1 January 2015 to end 2040, Scenario 1 produces a total of 40.9 MMbbl, Scenario 2 a total of 35.1 MMbbl, and the Downside Scenario a total of 23.6 MMbbl.

Operating Cost

All costs are in US$ real terms (RT) as at 1 January 2015. Removal of 2% inflation has been applied to the operators forecast where applicable.

Figure 5-8 shows the operating cost forecast applicable to all scenarios. Given operating cost is composed of a relatively low portion of variable costs, it is our opinion that each valuation scenario will carry similar operating costs – within the accuracy of the forecast. When assessing the impact of production rate changes on operating cost, we found there to be very little difference in cost between scenarios from 2015 through 2040.

Operating cost increases in the short term due to cost associated with the Maari Growth Project, and increased well intervention activity. Operating cost increases in 2018/2019 due to increased maintenance spending. Cost post 2024 has been forecast based on a moderate reduction in variable cost. The MODEC operations contract of US$32.6 million has been held constant in real terms until 2040. It should be noted that future market conditions may affect the ability to hold these costs constant in real terms. A +/- 10 percent operating cost sensitivity is recommended when assessing overall operating cost uncertainty.

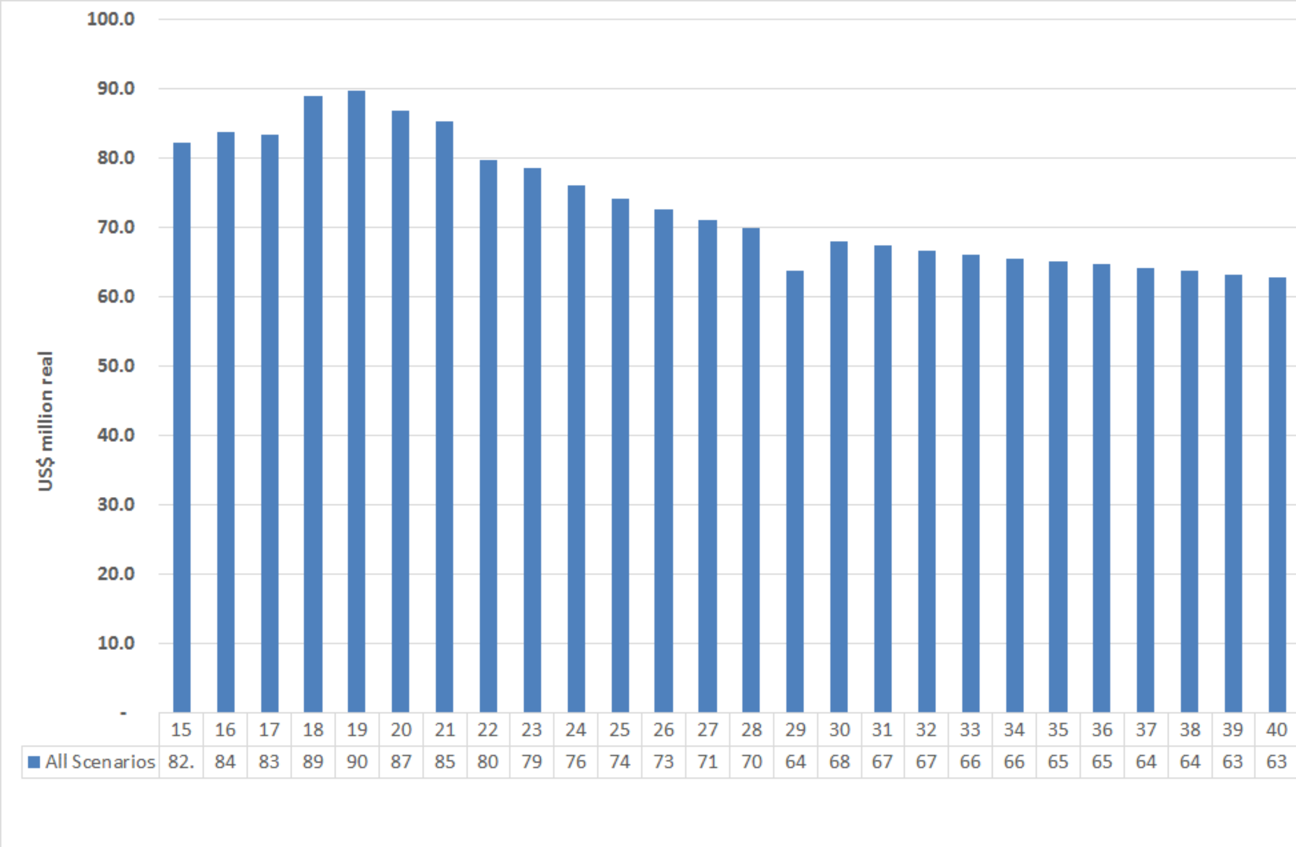


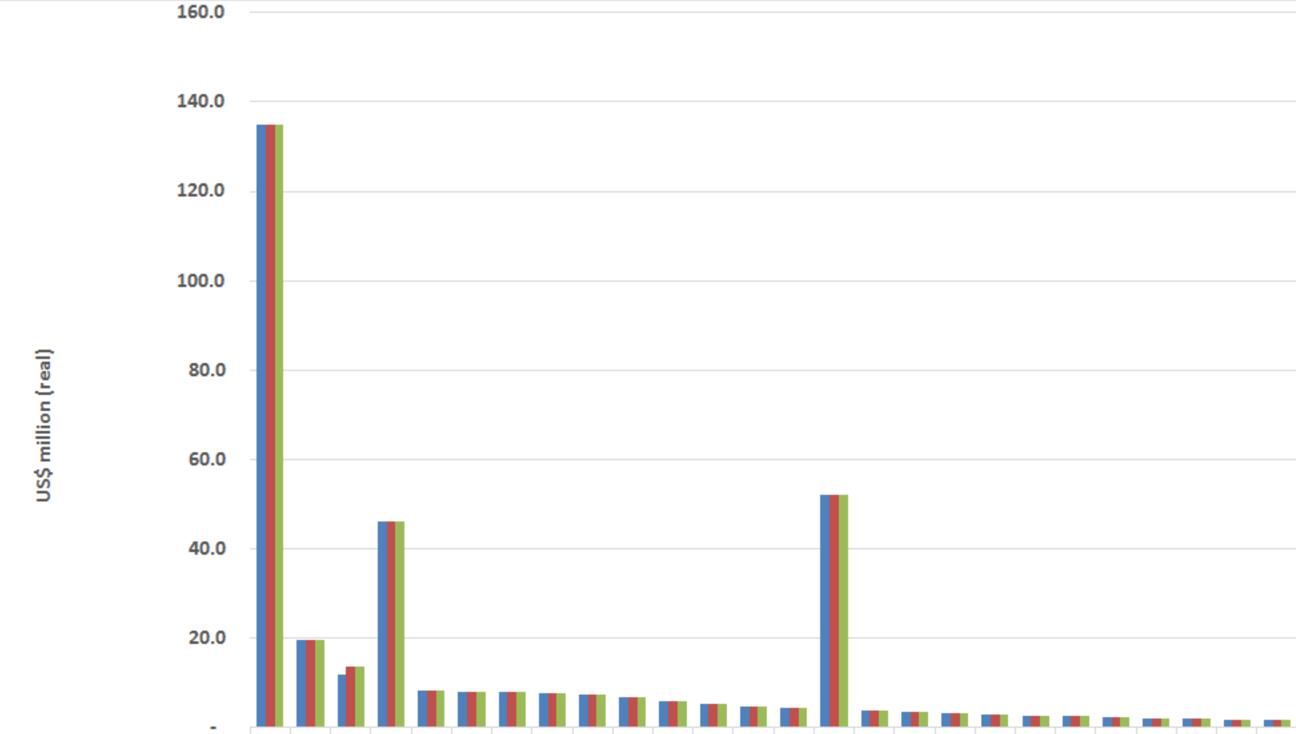
Figure 5-8 Maari Operating Cost Forecast RT 1/1/2015

Capital Cost

Figure 5-9 shows the capital cost forecast for each scenario. All costs are in real US$ terms as at 1 January 2015. Activities remain mostly constant across each scenario due to recent alignment on forward looking Maari Growth Project plans. The single exception is that Scenario 1 and 2 include US$2.0 million in 2017 for conversion of the Moki eastern flank producer into a water injector. This activity does not occur in the Downside Scenario where we consider that additional reservoir information may be available which does not justify the conversion. Wells drilling and completion costs are based on the Joint Venture retaining the ENSCO 107 rig under a contract extension if required. We are advised by Cue that equipment is available for all wells. 2016 includes US$5.7 million of capital cost for a planned FPSO topside upgrade. 2016 to 2018 includes US$43.8 million for a second mooring line repair project, with the majority of capital spent in 2018.

An allowance of US$50 million has been made in 2029 for life extension and refurbishment works for the FPSO and the WHP. These works are anticipated to be carried out to coincide with the 2029 Class inspection survey and will likely require dry-dock of the FPSO.

As there is some uncertainty in future performance, we recommend a -10% and +20% capital cost sensitivity is applied apply to the remaining Maari Growth Project expenditure.



	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
Downside Scenario Capex	134	19.	11.	46.	8.2	8.0	7.9	7.7	7.5	6.8	6.1	5.4	4.8	4.4	52.	3.7	3.4	3.2	2.9	2.7	2.5	2.4	2.2	2.0	1.9	1.7
Scenario 1 Capex	134	19.	13.	46.	8.2	8.0	7.9	7.7	7.5	6.8	6.1	5.4	4.8	4.4	52.	3.7	3.4	3.2	2.9	2.7	2.5	2.4	2.2	2.0	1.9	1.7
Scenario 2 Capex	134	19.	13.	46.	8.2	8.0	7.9	7.7	7.5	6.8	6.1	5.4	4.8	4.4	52.	3.7	3.4	3.2	2.9	2.7	2.5	2.4	2.2	2.0	1.9	1.7

Figure 5-9 Maari Capital Cost Forecast RT 1/1/2015

Abandonment Cost

Abandonment cost for all cases is estimated to be US$198 million. Abandonment costs include recovery and removal of the FPSO turret, WHP, and flexible flowline. The costs include a tow for the FPSO from New Zealand to South East Asia. Over half of the abandonment costs are related to wells.

5.2. PEP 51313 – Cue 14%

PEP 51313 is an offshore exploration permit with an area of 819 km^2 located approximately adjacent and south east of PMP38160 in the Taranaki Basin. The permit is operated by OMV New Zealand and has an expiry date of 29th July 2021. Cue has a 14% interest.

5.2.1. Exploration potential

The Whio prospect was investigated by Whio 1 in Q3 2014. The Whio prospect is an anticlinal closure at Miocene, Eocene and Palaeocene levels and is an independent closure 4.5 km south of the Maari Oil Field. The well encountered good quality reservoirs but was dry. The operator is still working on the final dry hole analysis for the well but a leading possibility for failure was identified as timing of charge. There is evidence of hydrocarbons having moved through the Whio area meaning there may still be some potential further up the Tasman Ridge. OMV has identified additional leads within the block (refer Figure 5-10).

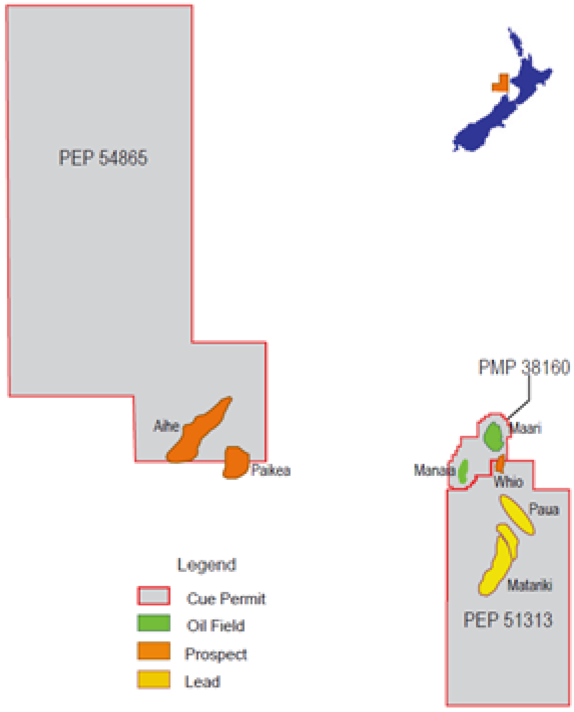


Figure 5-10: PEP51313 leads Paua and Matariki

The Matariki Lead is a north-south trending anticline covered by 3D. The primary reservoir targets are fluvial channel sands within the T10 sequence. The lead relies upon long-distance lateral migration from mature kitchens.

The Paua/Matariki stratigraphic leads are a series of small structural-stratigraphic traps located on the nose of the structural Tasman Ridge. Primary reservoir targets are fluvial sands within the T30 and T20 sequences (Mangahewa and Kaimiro Formations).

The prospectivity of the Block was impaired by the failure of Whio 1. The two remaining leads are considered to be high risk opportunities. Migration, seal and trap timing relative to hydrocarbon migration are the critical risks.

5.3. PEP 51149 – Cue 20%

PEP 51149 is located on the western side of Mt. Taranaki, on the Taranaki Peninsular, North Island of New Zealand (Figure 5-11). It covers an area of 819 km^2. Todd Energy is the permit Operator, Cue has a 20% interest. The expiry date of the Permit is 22nd September 2018.

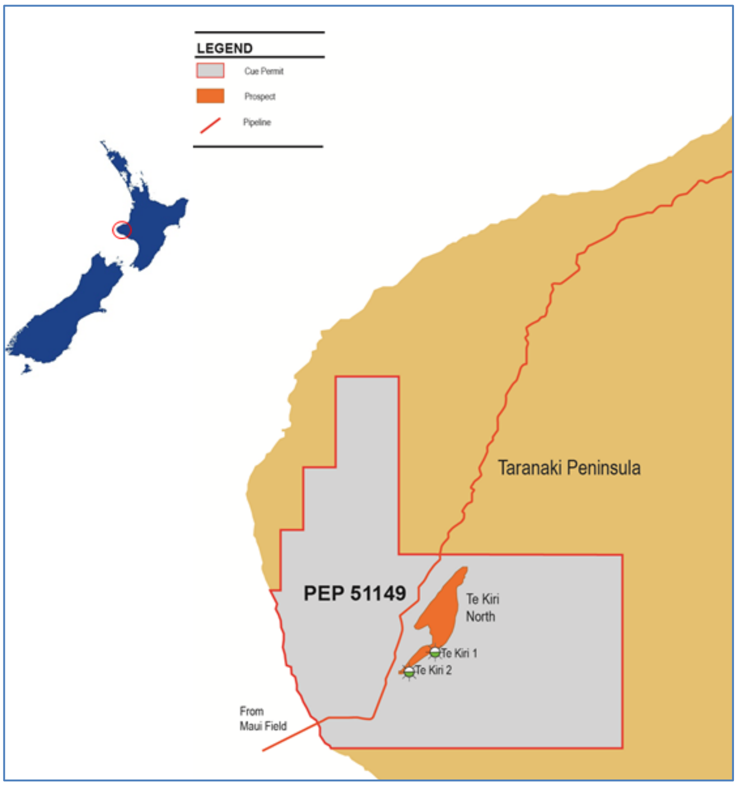


Figure 5-11: Location of PEP51149, onshore Taranaki Basin

5.3.1. Exploration potential

Todd has identified two prospects from the reprocessed Te Kiri 3D seismic survey: Te Kiri North and Arawhata. The shallower Arawhata prospect partially overlies the Te Kiri Noth prospect and Todd's plan is to drill an S-shaped exploration well to test both prospects from the same surface location.

The Arawhata targets are oil prone Miocene Mt Messenger and Moki Formations. The Te Kiri North targets are the wet gas prone Eocene Mangahewa and Kaimiro Formations. Primary targets are the Mt Messenger and Mangahewa Formations. Faulting in the top Mangahewa Formation gives rise to the potential for field compartmentalization. Reservoir continuity and net to gross is a risk in the Mt Messenger formation turbidite reservoir and Todd has used amplitude extractions to attempt to image sand distribution.

We have not conducted our own mapping or petrophysical analysis but based on our regional experience the Operator's volumetric parameter inputs for the primary reservoir targets are reasonable.

Production risks are reservoir quality, compartmentalisation, and degree of aquifer support which will affect both production rate and EUR per well.

Table 5-3: Te Kiri North and Arawhata gross unrisked P50 prospective resource volumes and risking values

Prospect	Arithmetic total Gas (bcf)	Arithmetic total Condensate/Oil (MMstb)	POS
Te Kiri North P50 resource (unrisked)	75	2.7	16%
Arawhata P50 resource (unrisked)	2.5	6	20%

The PEP51149 Joint Venture is committed to drill the Te Kiri North -1 well by December 2015. Dry hole well cost is estimated at $NZ 23-27 million.

The S-shaped well is relatively difficult to execute and a recent geomechanic study conducted by GMI has flagged potential drilling hazards associated with the high deviation angle (44 degrees) and the requirement to drill through a fault to intersect the deeper target reservoirs.

Cue is proposing a change of the well plan from a single deviated S-shaped well to two vertical wells: one to target the Miocene and the other to target the Eocene. Each vertical well would require a separate drilling pad as the subsurface targets are not geographically coincident. As yet there is no land holder agreement for the second drilling location. If Cue's suggested plan is adopted by the JV, the second well would be drilled 12-15 months after the first.

Additional leads/prospects exist within the Permit, however the focus is currently on Te Kiri North and Arawhata as they are considered to be the most prospective opportunities within the block.

5.4. PEP 54865 – Cue 20%

PEP 54865 is an offshore exploration permit with an area of 2475 km^2 located approximately 70 km west of the Maui Field in the Taranaki Basin. Expiry date of the Permit is 10th December 2017. It is operated by Todd Energy, Cue has a 20% interest.

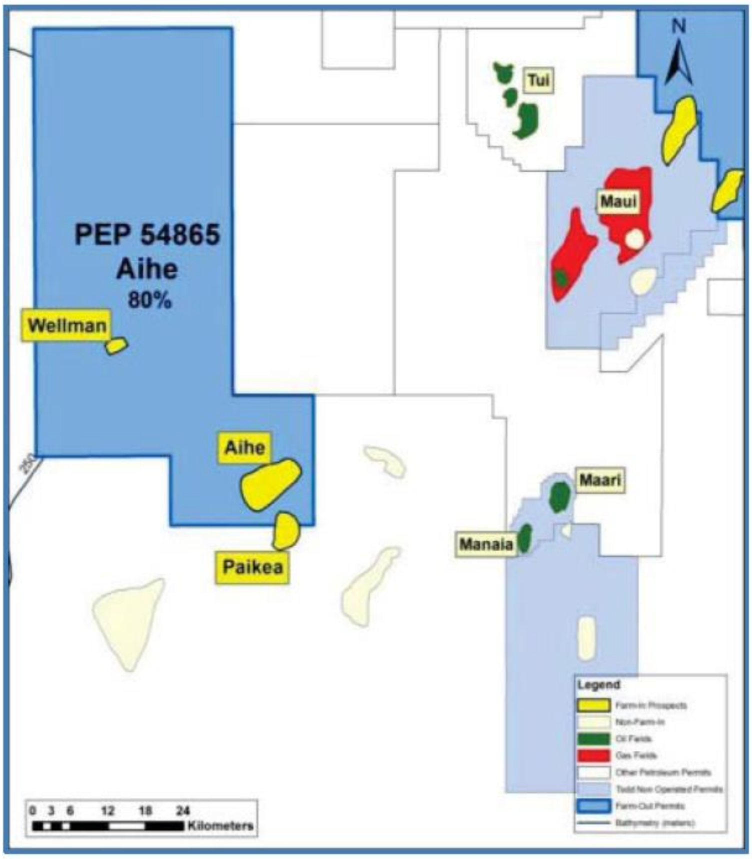


Figure 5-12: Location of PEP5486, offshore Taranaki Basin

The JV has applied to defer the acquisition of the 450 km^2 Sunset 3D seismic survey to 2016. There are no remaining well commitments.

Todd has identified two oil prospects, Ahie (P50 unrisked prospective resource 107 MMbbl) and Paikea (mean unrisked prospective resource 75 MMbbl)[3]

Aihe Prospect is a rotated basement high with material structural closure increasing with depth, located in the southeast of the permit. Primary play type is Palaeocene "F" Sand draped and trapped in a robust structural closure with direct access to migrating hydrocarbons from the adjacent Kahurangi Trough and sealed by overlying Cretaceous and Palaeogene mudstone. The play is on trend from the prolific Tui oil field 70 km to the NE.

Todd sees additional prospectivity with the Paikea structure identified on a basement horst drape located immediately southeast of Aihe with good access to charge.

An optional well could be drilled on either prospect. Cue has a drill or drop decision in Q3 2015, which would be deferred in tandem with the seismic acquisition deferral.

[3] Todd Energu Aihe Farmout Flyer – Offshore South Taranaki: PEP 54865 - Aihe

6. Indonesia

6.1. Sampang PSC (East Java, Cue 15%)

The Sampang PSC is located in the Madura Strait offshore of Madura Island, East Java. It is comprised of 4 sub-blocks and has a total area of 534.5 km^2. Santos is the Operator and Cue's interest is 15%. The Sampang PSC includes two producing Fields: the Oyong Oil Field and the Wortel Gas Field located in 45 m of water. The Jeruk oil discovery has yet to be developed.

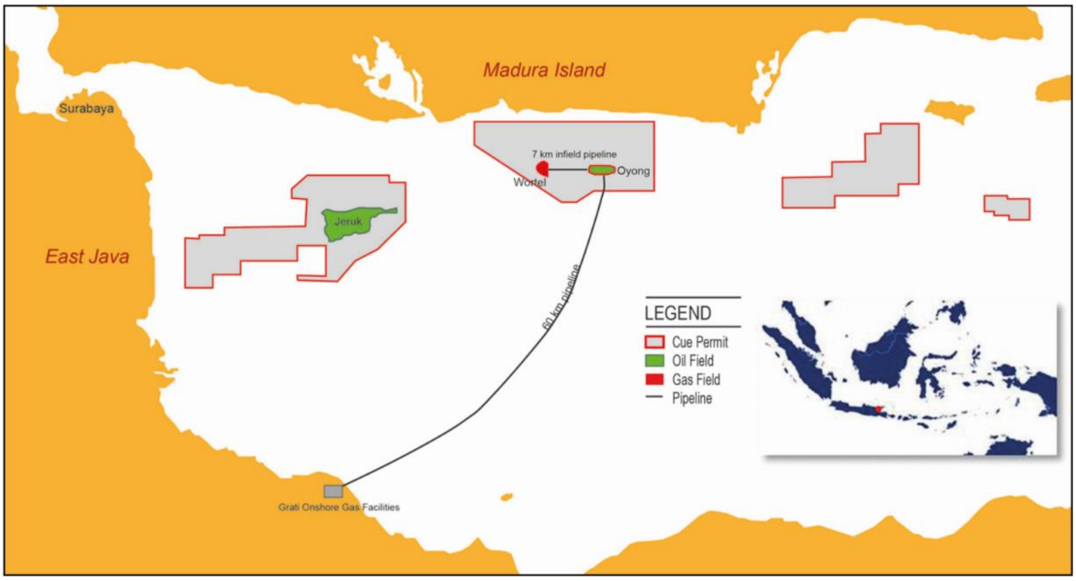


Figure 6-1: Wortel and Oyong location and gas flowlines

6.1.1. Geological setting

The tectonic evolution of the East Java Basin has been primarily controlled by the convergence of the Indo-Australian and Eurasian plates. The basin is situated on the southern margin of the stable Sunda Craton to the north of a volcanic arc, running through the centre of the island of Java[4]. It experienced a complex tectonic history with initial extension followed by periods of differential subsidence and later inversion. The structural grain of the basin was controlled by the fabric of the underlying basement. To the northwest of Madura Island in the Muriah Trough, Bawean Arch and Central Deep, this is predominantly NE-SW, whereas in the Kendeng Trough (onshore East Java) and the Madura Trough the orientation is E-W.

The Sampang PSC is located over the southernmost part of the Rembang-Madura – Kangean inversion zone which has been active since the end of the Early Pliocene

The stratigraphy of the East Java Basin reflects a balance between carbonate and clastic deposition, governed by the relative influences of tectonics, sea level and land-derived clastic input. Figure 6-2 shows a general stratigraphic column for the East Java Basin. The stratigraphic unit names in this area are not standardized.

[4] Magee,T; Buchan, C; Prosser, J. 2010. The Kujung Formation in Kurnia-1: A viable fractured reservoir play in the South Madura Block Formation . *In* proceedings, Indonesian Petroleum Association, 34th Annual Convention and exhibition, May 2010

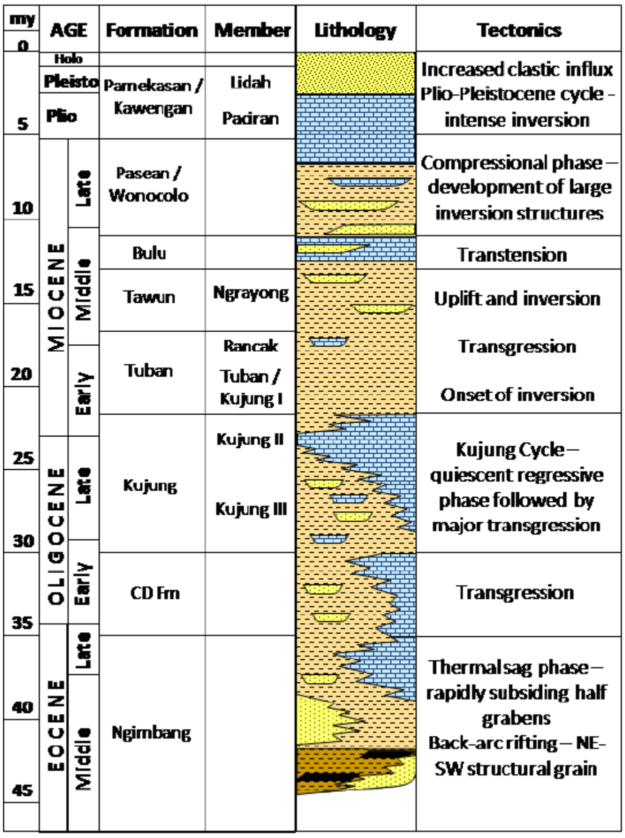


Figure 6-2: General stratigraphic column for the East Java Basin

The Piocene Mundu Formation reservoir facies at Oyong is dominated by fossils of Globigerian foraminfera, which consists of a detrital bioclastic limestones varying from high porosity, high permeability grainstones to poorer quality wackestones. This reservoir has both intre and intra-test porosity which results in very high porosities. The permeability varies from several milli-darcies to over 1 darcy [5]. Outcrop studies indicate that the Mundu formation is reefal facies deposited on the mid shelf to outer shelf Deposition was controlled by older normal faults on the mid-shelf.

6.1.2. Production and cost forecast

Wortel field

Wortel field is a gas field located approximately 7 km west of Oyong. The field has been on production since February 2012 with gas production at 31 December 2014 of 50 bcf. The field has two producing wells, Wortel 3 and Wortel 4. Gas from the field is produced via a flowline to Oyong, then via a common flowline to the Grati gas production facility, onshore East Java.

Total gas production to date has been at 45-50 mmscf/d, meeting the GSA limit. Additional compression facilities were installed at Grati in December 2014 to maintain the Wortel gas production rates and extend the production plateau. No further activity is planned. Condensate production from the field averages 0.6 bbl/mmscf. Historical production of the Wortel Field is shown below in Figure 6-3.

[5] Iriska, D, Sharp, N., Kueh, S. 2010. The Mundu Formation: Early production performance of an unconventional limestone reservoir, East Java Basin – Indonesia. *In* proceedings, Indonesian Petroleum association, 34th Annual Convention and exhibition, May 2010

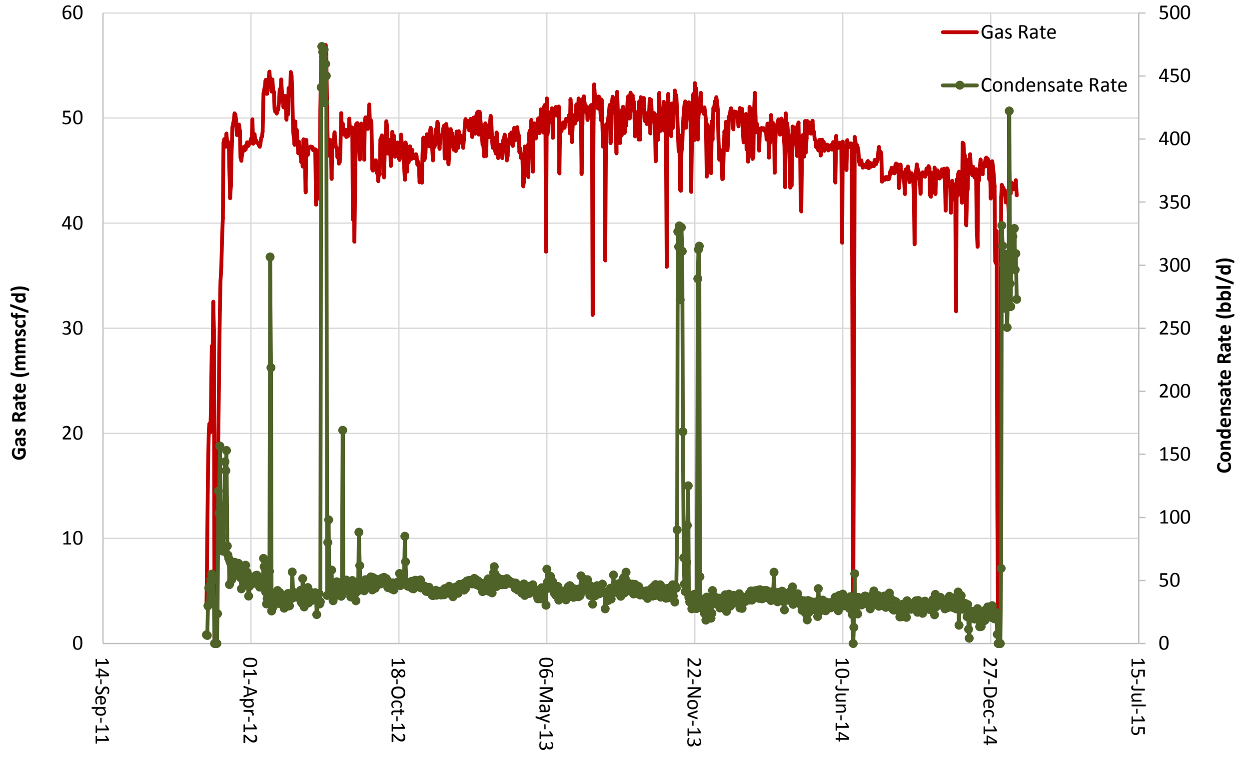


Figure 6-3: Wortel Historical Production Performance

RISC has analysed the gas and condensate production data and generated forecasts, taking into account the impact of the new compression. Forecasts were generated for 2 Scenarios which are 1P and 2P forecasts and are shown in Figure 6-4 prior to any truncation for economic limits. Scenario 1 produces 35.6 Mbbl of condensate and 46.5 bcf of gas to end 2020. Scenario 2 produces 43.1 Mbbl of condensate and 58.3 bcf of gas to end 2020.

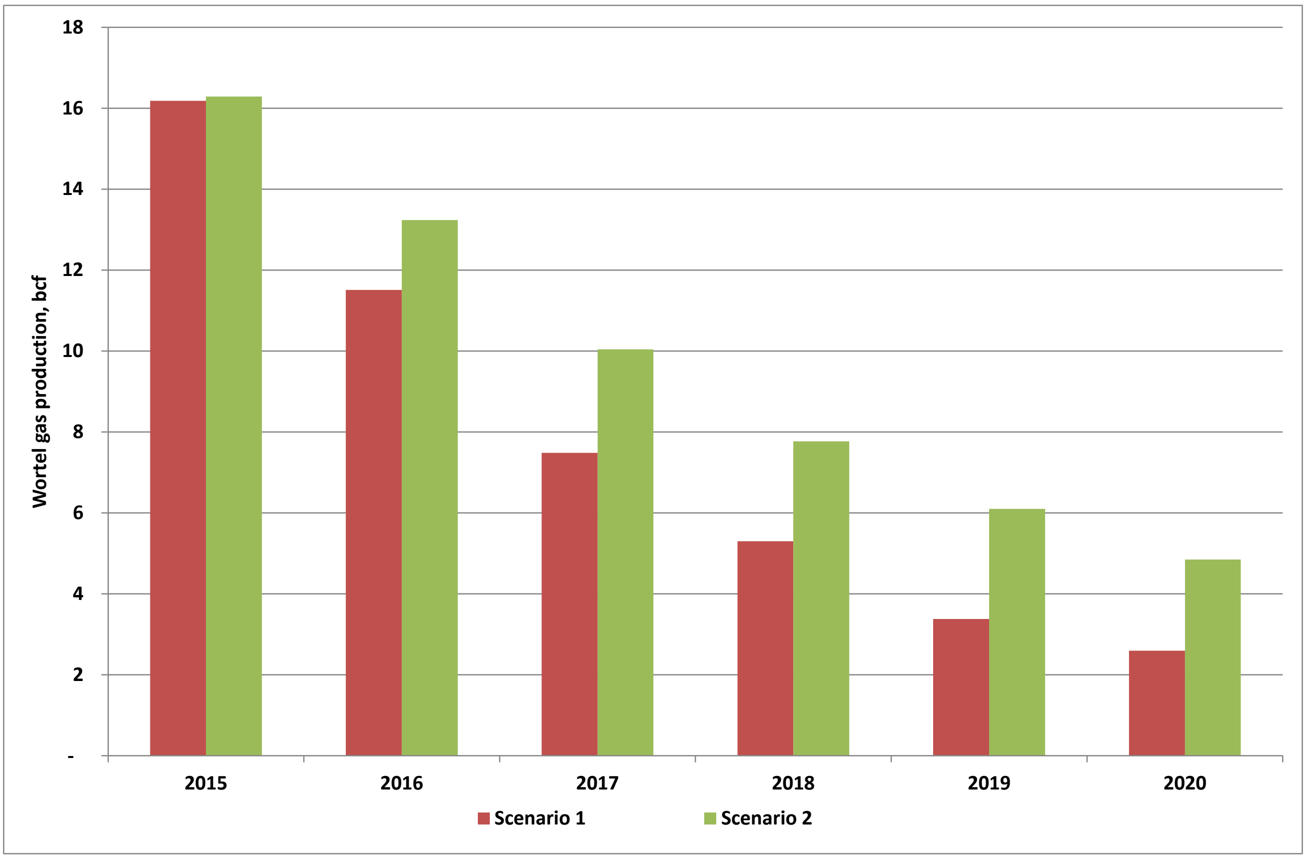


Figure 6-4 Wortel Gas Forecasts (untruncated)

Wortel operating and capital cost forecasts are shown in Figure 6-5 and Figure 6-6 respectively. Neither operating nor capital costs differ between scenarios. The high portion of fixed operating cost and relatively small proportional increase in production between scenarios would have little or no impact on cost. Operating costs reduce after 2015 due primarily to less workover/intervention activity.

No capital activities are planned for the remaining field life. An assumption has been made that a small capital spend will be required over the coming years – split equally between Wortel and Oyong.

Abandonment provisions have been reviewed by RISC. A US$4 million annual abandonment provision (for the Sampang PSC – includes Oyong) allocated over approximately 10 years of field life aligns with RISC abandonment estimates for a similar scope in Indonesia. RISC does not have visibility of abandonment provisions outside the 2015 budget and has allowed for provisions are that are similar each year.

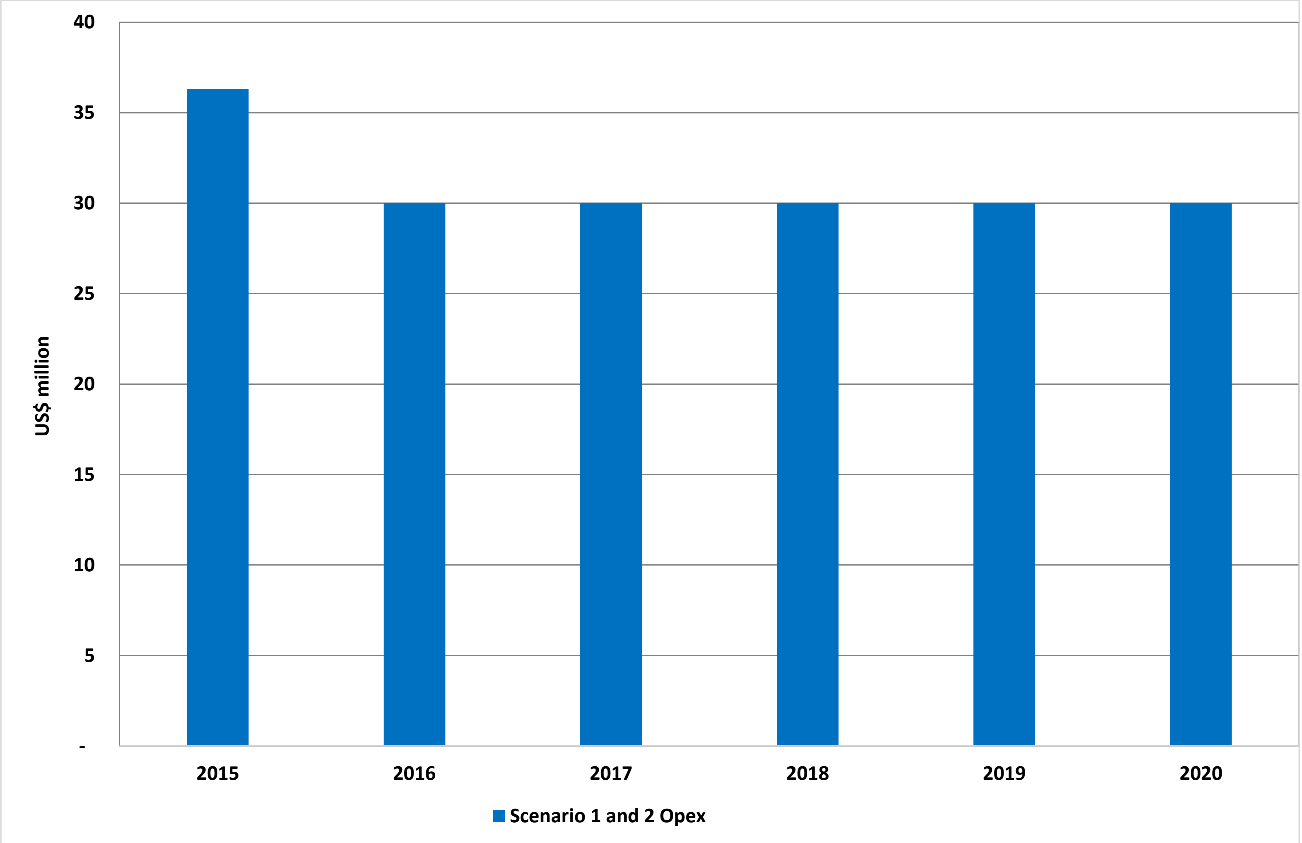


Figure 6-5: Wortel Operating Cost Forecast (Scenario 1 and 2)

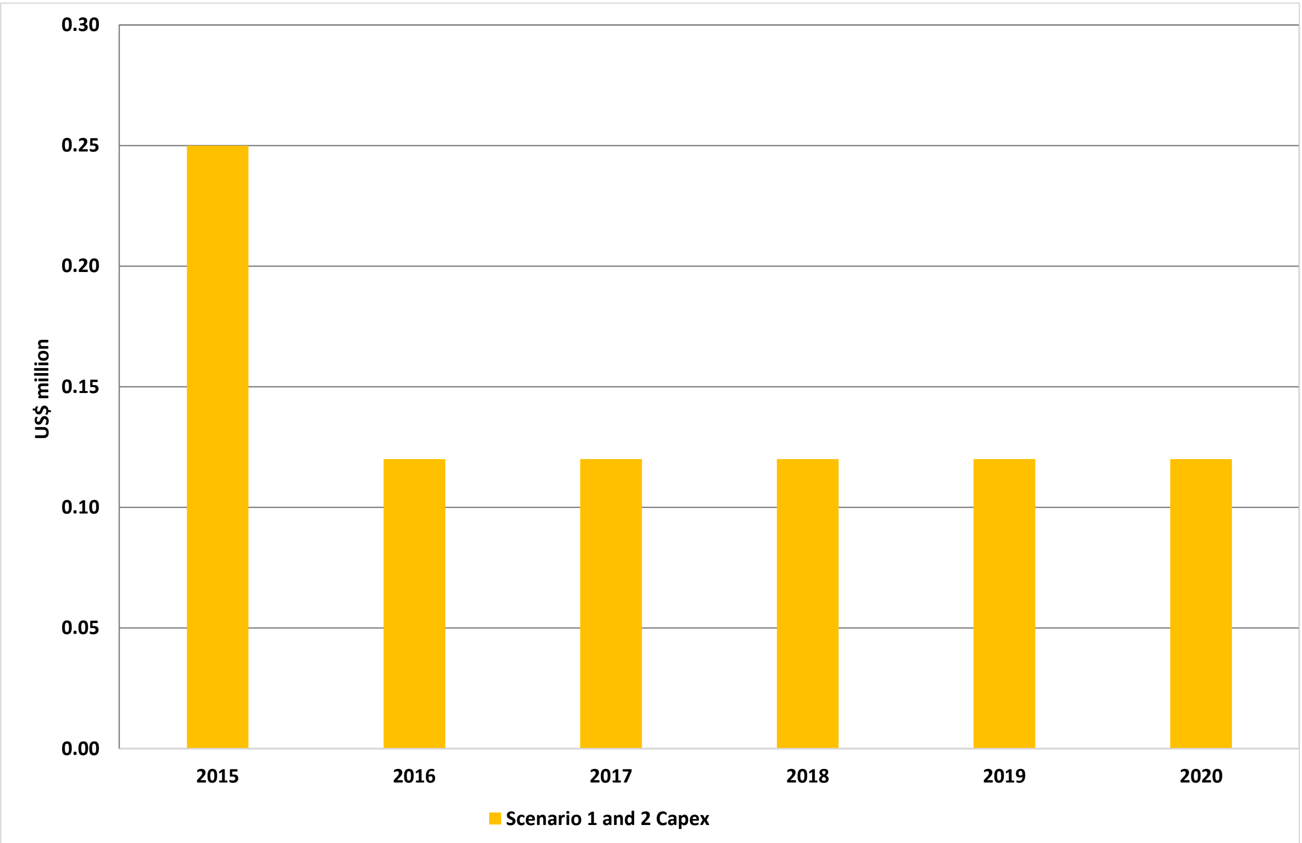


Figure 6-6: Wortel Capital Cost Forecast (Scenario 1 and 2)

Oyong field

The Oyong has an oil rim of approximately 38 m thick, overlain by a gas cap of approximately 110 m. Oil production commenced in September 2007, gas production in September 2009, with a total of 8.8 mmbbl oil and 71 bcf gas produced to 31 December 2014.

Oil production was 8-10,000 bbl/d initially, but had declined to 1,200 bbl/d in December 2014. Many wells had shown increasing water production and only 3 wells (Oyong 4, 5 and 11) remained on production in December 2014. In January 2015 workovers started on four wells to attempt to restore or improve production:

- Oyong 11 – workover attempted to establish production from the non-producing zone and acidize the other to increase rate;
- Oyong 7, 8 and 9 – workover to isolate water producing lateral and re-perforate higher in well.

Limited data are available following the activities. The workover on Oyong 9 appears to have been very successful with production rates to date exceeding the expected total for the four workovers. The other workovers were not initially successful, but further work is being conducted to achieve planned outcomes. Oyong 7 and 8 were not re-perforated due to mechanical issues following the isolation of the lower section and Oyong 11 has not shown any improvement in rate to date. Historical production performance of the Oyong Field is shown below in Figure 6-7.

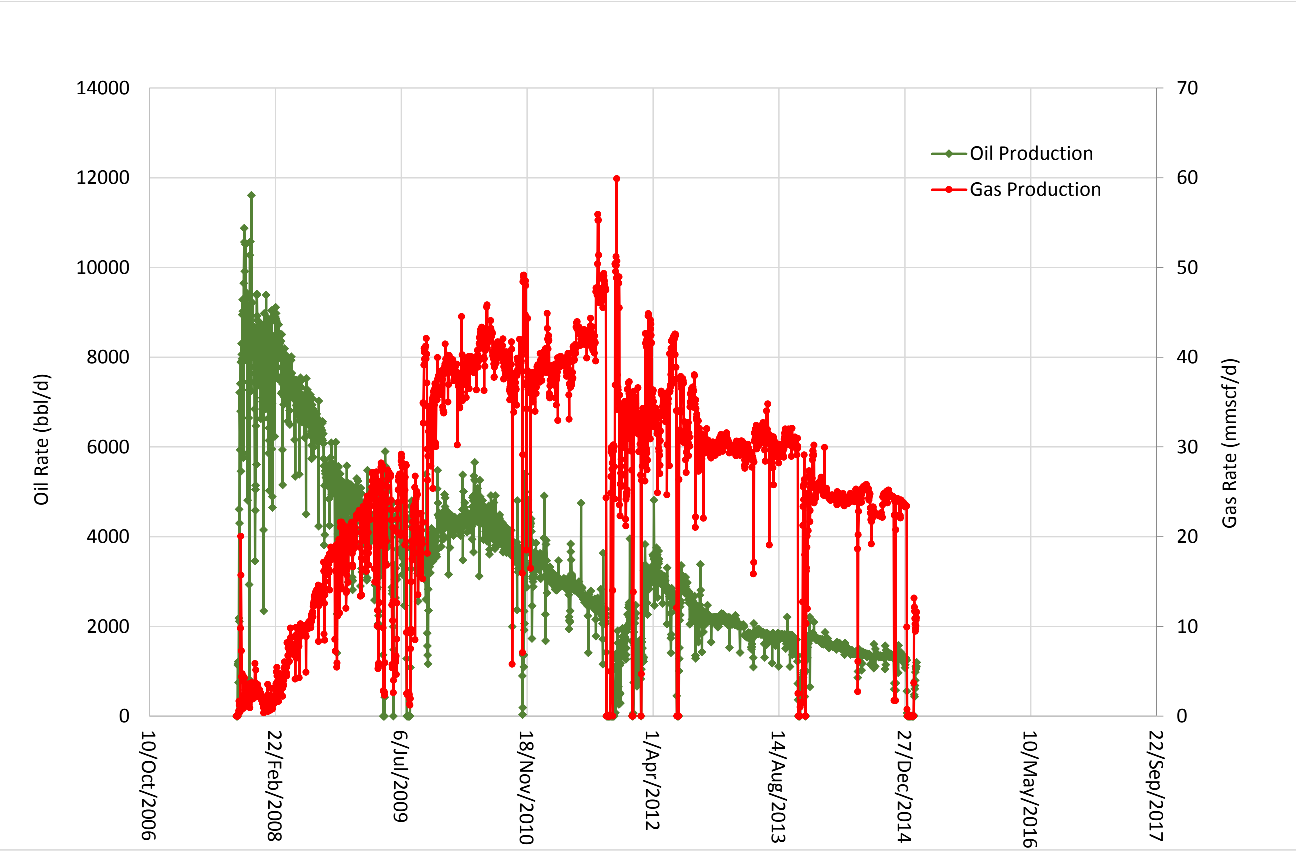


Figure 6-7: Oyong Historical Production Performance

RISC has reviewed the production performance of the wells, both before and after the workovers, and has generated two Scenarios. Oil production for both cases is shown in Figure 6-8. Scenario 1 produces 1716 Mbbl of oil and 27.4 bcf of gas to end 2020. Scenario 2 produces 2493 Mbbl of oil and 39.8 bcf of gas to end 2020.

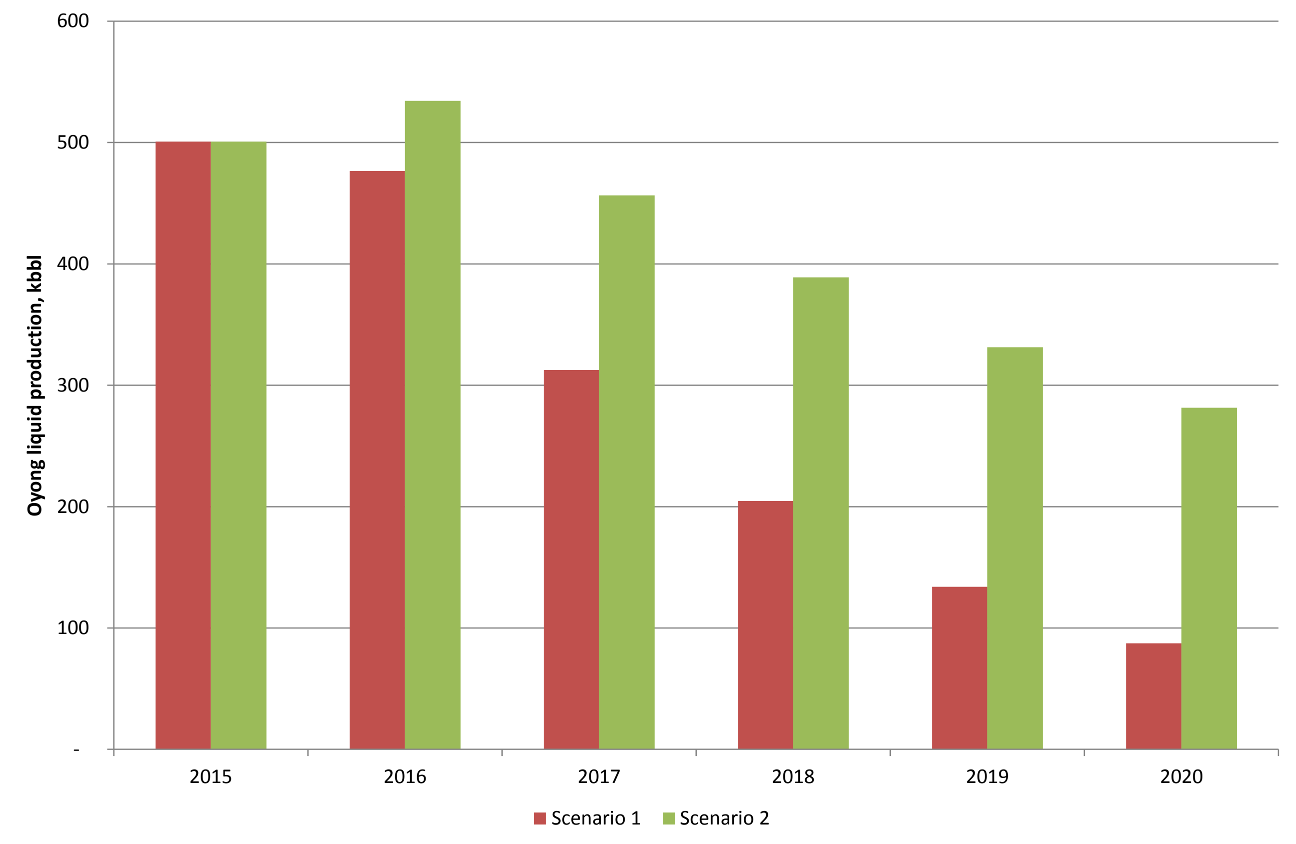


Figure 6-8: Oyong valuation case oil forecasts (untruncated)

The oil production facility at Oyong (FPSO and barge) is contracted to September 2015 and this truncation date formed the basis for low reserve estimates. The JV recently voted to negotiate to extend the FPSO contract for up to 3 years, however to date no confirmation has been received that this has happened. Production and cost forecasts have been generated beyond the estimated economic limit to enable economic assessment of the field abandonment date.

Oyong operating and capital cost forecasts are shown in Figure 6-9 and Figure 6-10 respectively. Like Wortel, neither operating nor capital costs differ between scenarios. The high portion of fixed operating cost and relatively small proportional increase in production between scenarios would have little or no impact on cost. Operating costs reduce after 2015 due primarily to less workover/intervention activity.

No capital activities are planned for the remaining field life. An assumption has been made that a small capital spend will be required over the coming years – split equally between Wortel and Oyong.

Abandonment provisions have been reviewed by RISC. A US$4 million annual abandonment provision (for the Sampang PSC – includes Oyong) allocated over approximately 10 years of field life aligns with RISC abandonment estimates for a similar scope in Indonesia. RISC does not have visibility of abandonment provisions outside the 2015 budget and has allowed for provisions that are similar each year.

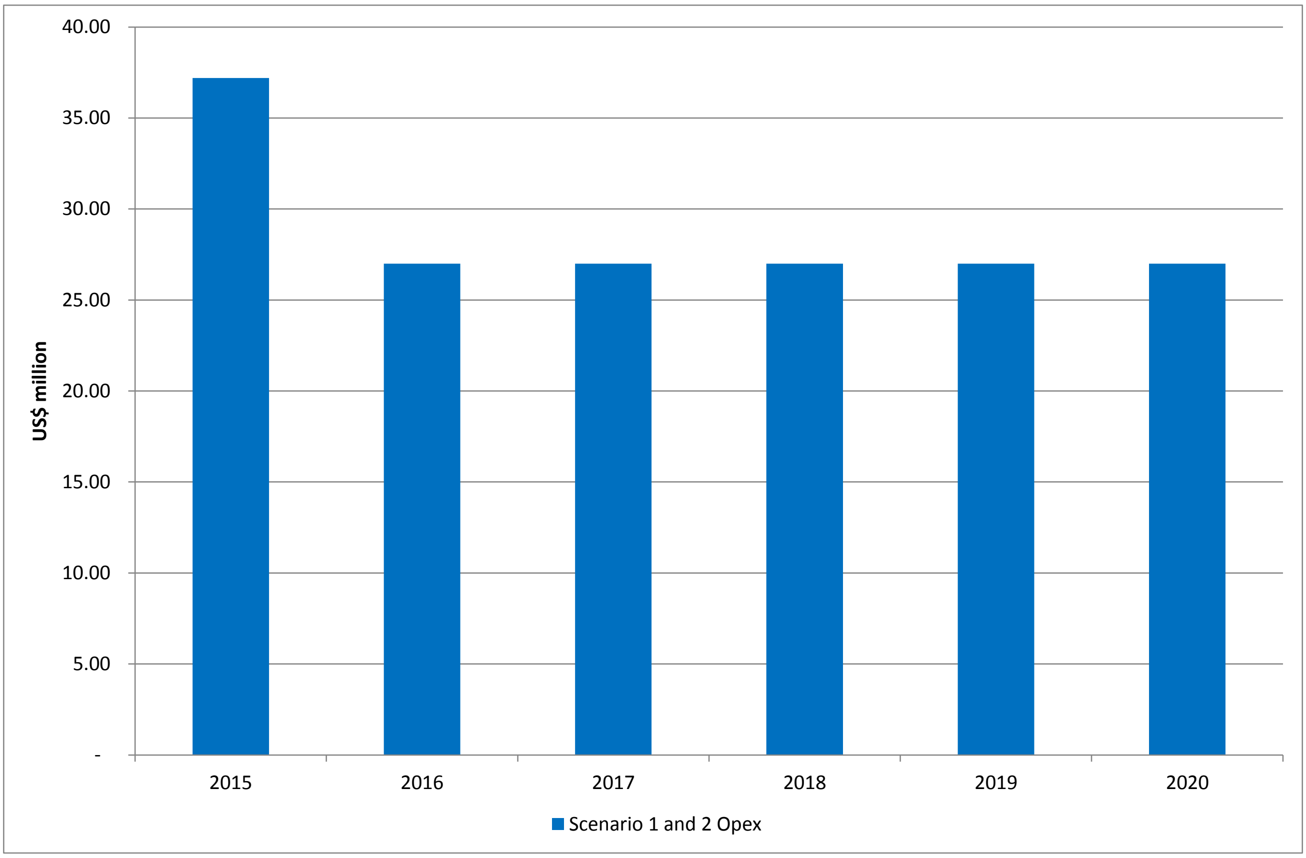


Figure 6-9: Oyong Operating Cost Forecast (Scenario 1 and 2)

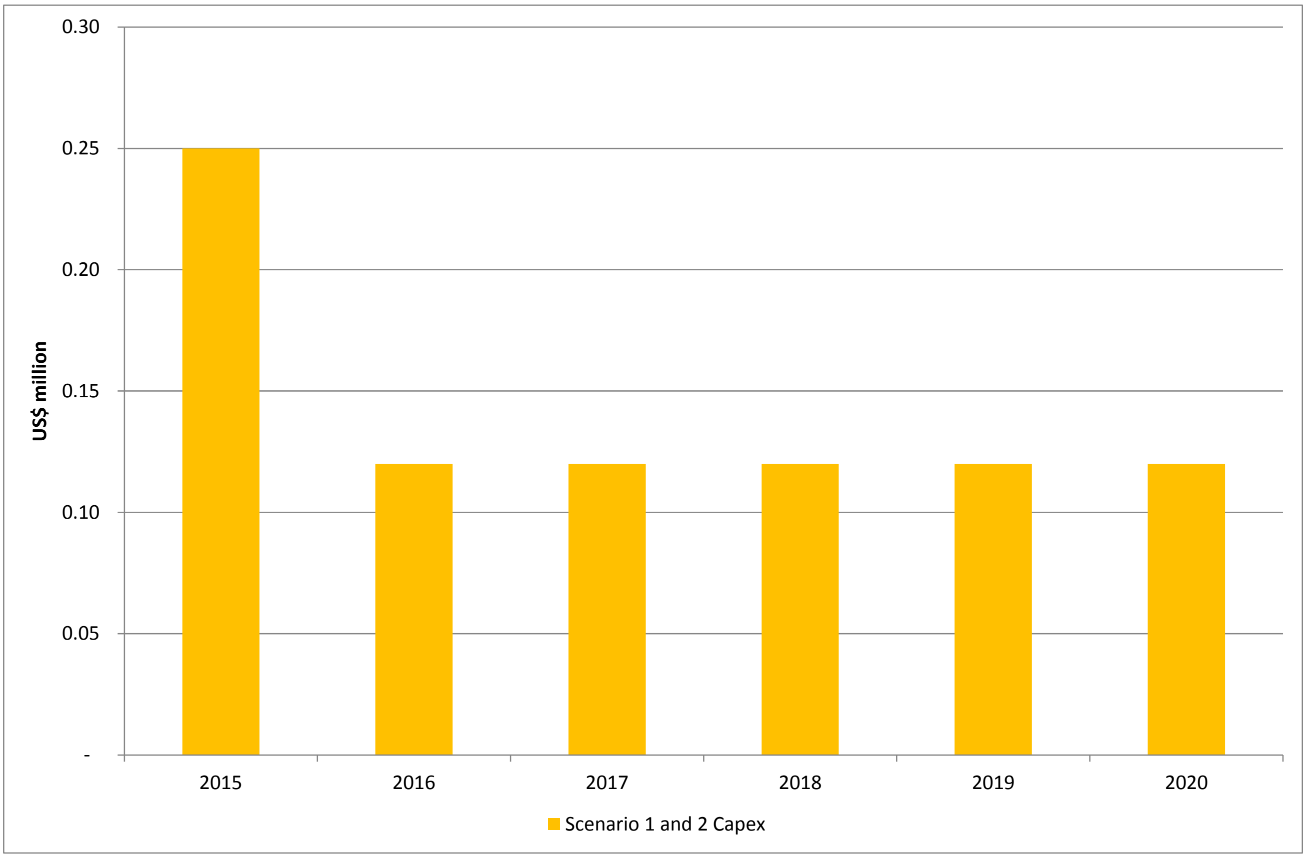


Figure 6-10: Oyong Capital Cost Forecast (Scenario 1 and 2)

6.1.3. Remaining Production

The remaining oil and gas production in the Sampang PSC estimated by RISC for the two valuation scenarios to 2020 is shown in the table below as at 1 January 2015.

Table 6-1 Sampang PSC Gross Remaining Production 1 January 2015

Field	Scenario 1		Scenario 2	
	Gas bcf	Oil/Cond Mbbl	Gas bcf	Oil/Cond Mbbl
Oyong	27.4	1,716	39.8	2,493
Wortel	46.4	35.6	58.3	43.1
Total	73.8	1,752	98.1	2,536

6.1.4. Jeruk Discovery

In addition to the two producing fields, Wortel and Oyong, the Sampang PSC contains the Jeruk discovery, some 35 km west of Oyong. The field was discovered in 2003 with the drilling of Jeruk 1 and subsequently appraised with Jeruk 2 (and sidetracks) in 2004 and Jeruk 3 in 2006. Notwithstanding the appraisal there remain considerable technical uncertainties and difficulties in commercialising the field due to:

- Structure – significant GRV uncertainty at the crest due to steeply dipping overburden section and multiples affecting seismic imaging;
- Reservoir – fractured, vuggy heterogeneous carbonate reservoir, unknown compartmentalization;
- Fractures – uncertain fracture density and distribution and degree of dolomite alteration; and
- Reservoir dynamics – limited understanding of reservoir connectivity and drive mechanism.

Further, there are production issues resulting from the nature of the fluid:

- High temperature/high pressure with 3,300 psi overpressure;
- High wax appearance temperature;
- Stable emulsion formation;
- High H_2S content in gas (>2%); and
- High CO_2 content of gas (26%).

The field has been extensively reviewed by the JV in the 12 years since its discovery. At the recent TCM (December 2014) the operator concluded that "development was uneconomic" (2P case based on NPV10). It was stated that this conclusion was based on the operator's "2013 Corporate Assumptions with a $5/bbl quality discount". Whilst the details of this cost assumption are not known it is believed to be higher than the current forecast. No schedule of costs and production has been provided.

RISC considers that, in the current oil price environment, the field is likely to still be uneconomic and assigns no value to the asset.

6.2. Mahato PSC (Central Sumatra, Cue 12.5%)

The Mahato PSC is a large block (5.700 km^2) located in the prolific and oil-rich Central Sumatra Basin. It was awarded to the current holders in 2012 for a period of 6 years. The work program in the first 3 years consists of 200km 2D Seismic and one 1 well. In years 4-6, 1 well.

25% of original area is required to be relinquished by end of year 3 or 40% if the first 3 years work program is unfulfilled with 80% Relinquishment by the end of year 6. The signature, equipment and information bonuses total $1.1 million.

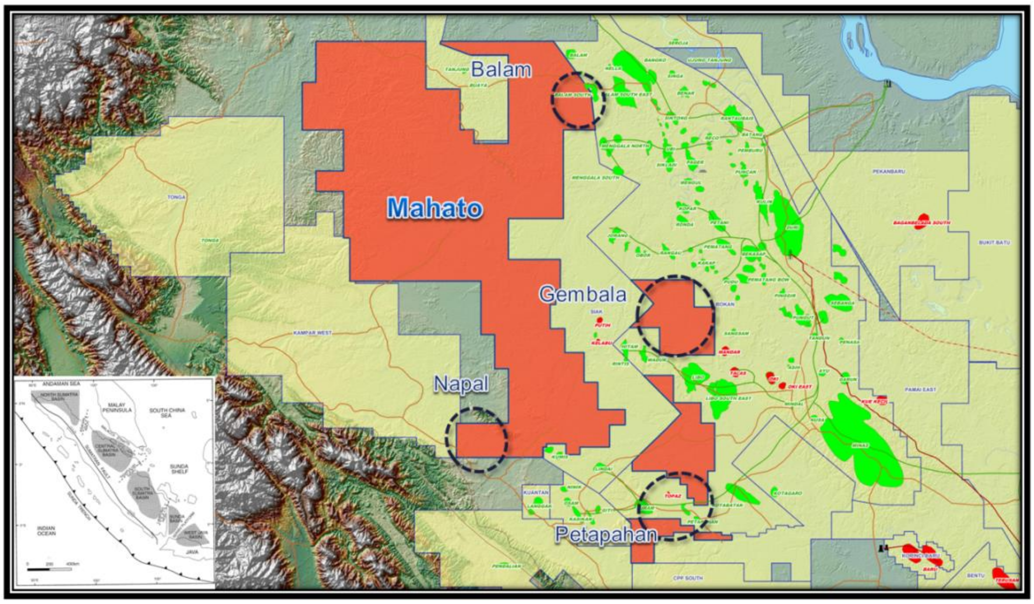


Figure 6-11: The Mahato PSC is located in the Central Sumatra Basin

The Central Sumatra Basin, Figure 6-12 is the most prolific oil basin in Southeast Asia with over 11 billion barrels oil produced to date. It was formed during the Early Tertiary (Eocene-Oligocene) as a series of half grabens and horst blocks developed in response to an East-West extensional regime. Primary reservoirs are the Tertiary Bekasap (Early Miocene) and Pematang (Early Oligocene).

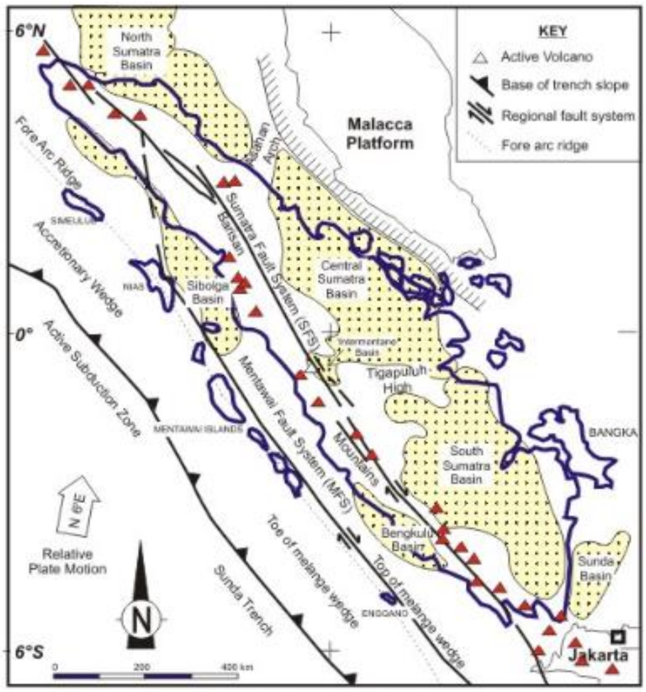


Figure 6-12: Regional tectonic setting of Sumatra

The Mahato PSC is situated near rifted Miocene aged lacustrine source rocks. The western half of the block is interpreted to be in a migration shadow zone.

The permit was previously held by Chevron and Conoco and 17 wells have been drilled in the block mostly in the early 1970s.

Cue's exploration focus is on 3 cluster areas and the Napal area. Its' strategy is to drill wells near existing fields and source kitchen to minimize migration and charge risk.

The eastern area is viewed as a low-moderate risk area whereas the western and northern areas represent higher risk due to the current lack of understanding of possible source kitchens.

Cue has carried out significant analysis of the prospectivity of the permit as part of its due diligence work prior to its farmin. There are twenty leads and prospects included in Cue's Mahato PSC prospects and leads inventory. These range in size from 2 to 33 MMbbl P50 prospective resources, with geological probability of success ranging from 5-80% with an average of about 20%. The aggregate P50 prospective resource is approximately 200 MMbbl.

Two prospects are deemed drill ready (PA and PB) with the third requiring additional seismic (BA). PA and PB are near field exploration and could be quickly tied into existing infrastructure. The PA prospect is a possible extension of Chevron's Petapahan "C" Field. PB is a fairly mature prospect nearby, and is currently scheduled to be drilled back to back with PA. It could be jointly developed with PA.

The PA prospect is an extension of the Petapahan "C" field. The prospect is defined by two seismic lines and therefore structural uncertainty is large.

Total depth for the well is prognosticated to be at approximately 1750 m. Reservoir targets are the Bekasap A-B-C sands.

It is considered that the reservoir drive will be depletion as in Petapahan field. The well will provide pressure information that will determine if the extension is being depleted. It will also provide information regarding OWC movement and whether the reservoir is compartmentalised (similar to Kotabatak field).

The PB prospect is also close to the PA prospect. It is a faulted 3 or 4 way dip closure. The primary reservoir is Bekasap sands (A-B-C). TD is estimated to be at approximately 1750 m. The Pala-1 well drilled nearby was dry, but the well may have been drilled off structure. Fault seal is also a risk. The PB prospect is independent of PA and therefore is a good follow up prospect.

RISC has checked Cue's volumetric assumptions and they are reasonable.

Cue's notional development plan for the Petapahan area cluster includes simple well heads with pump units. PA production would be tied into the PB Field. Oil water separation would be at the PB development. Raw oil will tie in and be separated at the Chevron operated Petapahan Field. Dry oil from the Petapahan cluster would be exported vial a 22km 18" pipeline from the Petaphan Field to the Kotabak Field.

The BA prospect is a faulted 4-way dip closed structure. It is close to Udang-1 which had possible missed pay in the Pematang. Reservoir targets are Pematang sandstones at approximately 800 m and possibly fractured basement. The primary risks are charge as the structure may be in a migration shadow and poor reservoir quality. Additional seismic is required to define a drilling a location.

Cue's volumetric parameter ranges have been reviewed and are reasonable.

In summary, the eastern side of the Mahato PSC appears to be highly prospective. Cue's probabilistic resource estimates and risking of the leads and prospects shown are reasonable given the current information available. In making this assessment RISC has not carried out its own independent review of the seismic dataset or existing well database and our opinion is based upon our regional experience and Cue's due diligence work presented in several management presentations.

6.3. Mahakam Hilir PSC (Kalimantan, Cue 100%)

Makaham Hilir PSC in Kalimantan covers an area of 275 km2. The permit expiry date is 13th November 2015. An application has been made to award operatorship to Cue (100% WI) is pending Government of Indonesia approval.

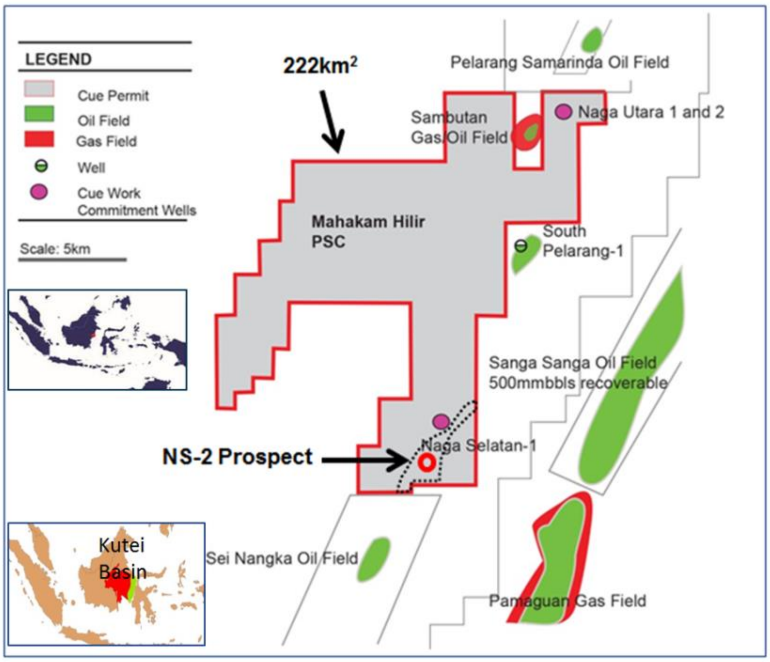


Figure 6-13: Mahakam Hilir PSC location

The Mahakam Hilir PSC overlies the Kutei Basin in Kalimantan. The Kutei Basin is the largest (165,000 km^2) and the deepest (12,000 – 14,000 m) Tertiary sedimentary basin in Indonesia. The Tertiary stratigraphic succession within the basin commenced with the deposition of Paleocene alluvial sediments in the inner basin, close to the western border. The basin subsided during the late Paleocene – Middle Eocene to Oligocene, due to basement rifting, and became the site of deposition of the Mangkupa Shale in a marginal to open marine environment. Some coarser siliciclastics, the Beriun Sands, are locally associated with the shale sequence, indicating an interruption of basin subsidence by uplift. The basin subsided rapidly after the deposition of the Beriun Sands, mostly through the mechanism of basin sagging, resulting in the deposition of marine shales of the Atan Formation and carbonates of the Kedango Formation. Subsequent tectonic events uplifted parts of the basin margin by the late Oligocene. This uplift was associated with the deposition of the Sembulu Volcanics in the eastern part of the basin.

The second stratigraphic phase was contemporaneous with basin uplift and inversion, which started in Early Miocene time. During that time, a vast series of alluvial and deltaic deposits (Pamaluan, Pulubalang, Balikpapan and Kampung Baru formations) were deposited in the basin prograding eastwards, which range in age from the Early Miocene to Pleistocene times. Deltaic deposition continues to the present day, and extends eastwards into offshore Kutei Basin.

At present, the structural style of the Kutei Basin is dominated by a series of tight NNE – SSW trending folds that parallel the arcuate coastal line, and are known as the Samarinda Anticlinorium – Mahakam Foldbelt. These fold belts are characterized by tight, asymmetric anticlines, separated by broad synclines, containing Miocene siliciclastics. These features dominate the eastern part of the basin and are also identifiable offshore. The deformation is increasingly more complex in the onshore direction and the western basin area has been uplifted. The origin of folds and faults in the Kutei Basin remains unresolved.

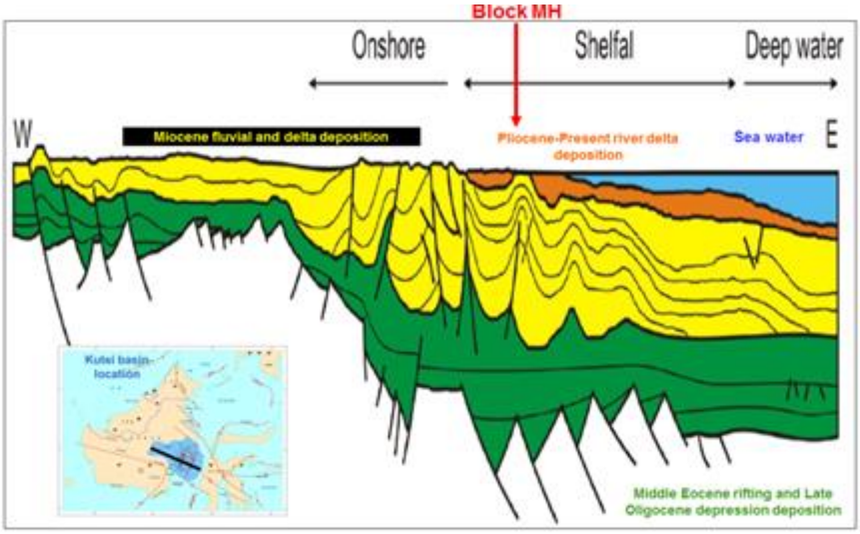


Figure 6-14: Kutei Basin cross section

The Mahakam Hilir PSC is adjacent to several significant oil and gas fields located south and west of the PSC boundary, Figure 6-15.

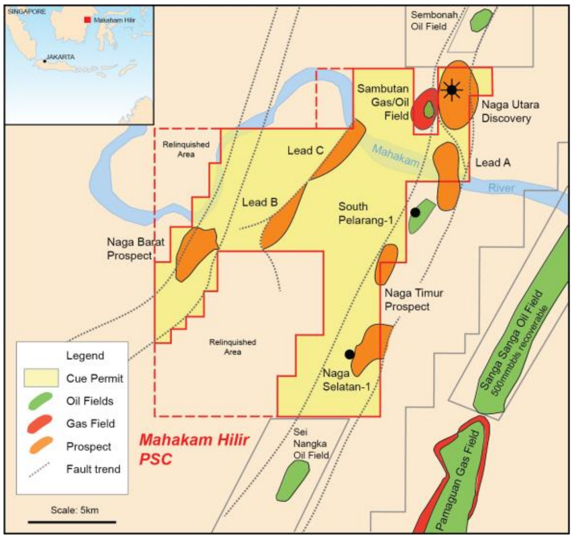


Figure 6-15 Mahakam Hilir PSC prospects, leads and adjacent fields.

The Naga Utara (NU) tight gas discovery in the north east of the permit has yet to be developed. NU 1 intersected gas within the Miocene sandstones. The appraisal well NU 2 was a dry hole that failed to intersect reservoir quality sandstones. A drilling pad was prepared for NU 3 but the well was not drilled.

Cue has not estimated resources for Naga Utara-3.

Several leads have been identified within the PSC, shown in Figure 6-15. Several of the leads are associated with surface oil seeps. Most are weak leads as they are poorly covered/imaged by seismic. The majority will be retained by not relinquishing the crestal areas in the 2015 final relinquishment. The area on block in the vicinity of South Pelarang 1 is a target for shallow oil discovered in that well, but the potential has only recently been realised by Cue and has not been fully evaluated.

The Naga Selatan (NS) prospect in the south west of the permit is a drill ready prospect that Cue is planning to drill in Q3 2015. The Naga Selatan structure was tested by the SPC Selatan-1 exploration well in 2012. The primary objectives were the N-8 to N-9 intervals of the Mid Miocene of Balikpapan Deltaic Sandstone.

The well reached TD at 8300 ft MD (2530 m) in June 2012 taking 70 days to drill. The open hole wireline log interpretation results indicated that the sands were water saturated and the well was plugged and abandoned.

Drilling shows were observed over a shallower (younger) interval from 1200 ft to 1650 ft (366 – 503 m) consisting of interbedded sandstone, shale and siltstone which is interpreted by ETTI as representative of a delta front environment Figure 6-16.

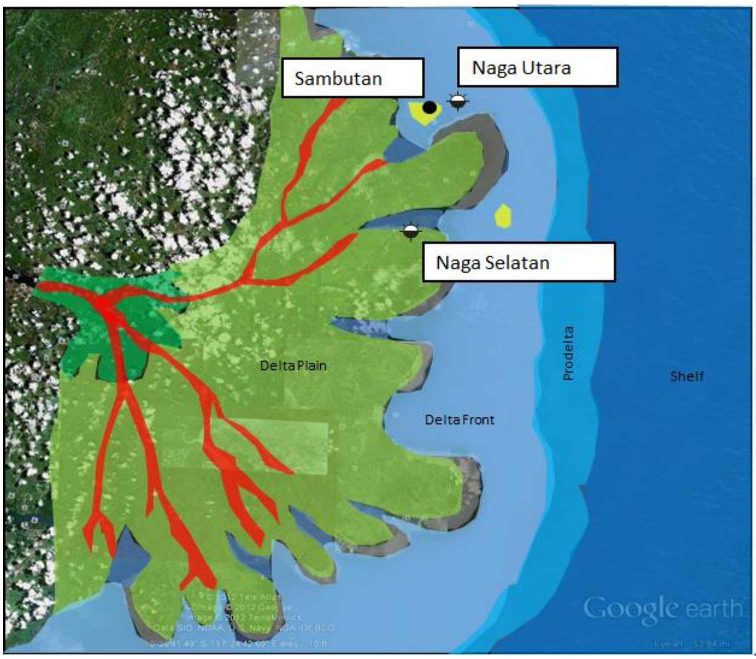


Figure 6-16: Interpreted depositional setting Mahakam Hilir PSC

Drill cuttings are described as indicate coarse grained sands with poor visual porosity. The upper show is described as, 5-10% yellowish gold fluorescence, slight odor, white yellowish very slow crush cut[6].

Cue re-evaluated the well result and was encouraged by the shallow hydrocarbon shows which it interprets to be residual hydrocarbons suggesting that that the well is located on hydrocarbon migration pathway. Furthermore Cue believes that the low resistivity response of the informally named “1200 ft” sand that had previously be interpreted caused by high water saturation could alternatively be a mineralogical effect and is not a true fluid response.

Cue’s proposed NS-2 well is a further test of “1200 ft sand” on the NS structure, but the well will be located to intersect the top “1200 ft sand” approximately 350 ft (107 m) updip of the NS 1 location. The final location is still being reviewed.

We support Cue’s volumetrics (Table 6-2).

[6] Naga Selatan-1 Final Well Report, June 2012 SPC Mahakam Hilir PTE LTD

Table 6-2: NS updip prospect unrisked prospective resources (gross, Cue at 10% WI)

Prospect	Unrisked STOIIP (mmstb)			Unrisked EUR (mmstb)		
	P90	P50	P10	P90	P50	P10
NS Updip Gross	10	64	205	5	18	62

Reservoir and charge/migration have been demonstrated by the NS-1 well. Seal and trap are the critical uncertainties and RISC assigns a geological chance of success of 30% to the NS updip prospect.

Cue's notional P50 case development includes an additional appraisal well and 17 development wells ($34 million) to develop 18.7 MMbls of 2P reserves. The estimated facilities cost is $23 million which includes 3 phase separation and onsite oil storage. Dry oil will be trucked for export. Total estimated capex is US$65 million.

7. Australia

Cue has interests in 5 exploration permits located in the Northern Carnarvon Basin, offshore Western Australia.

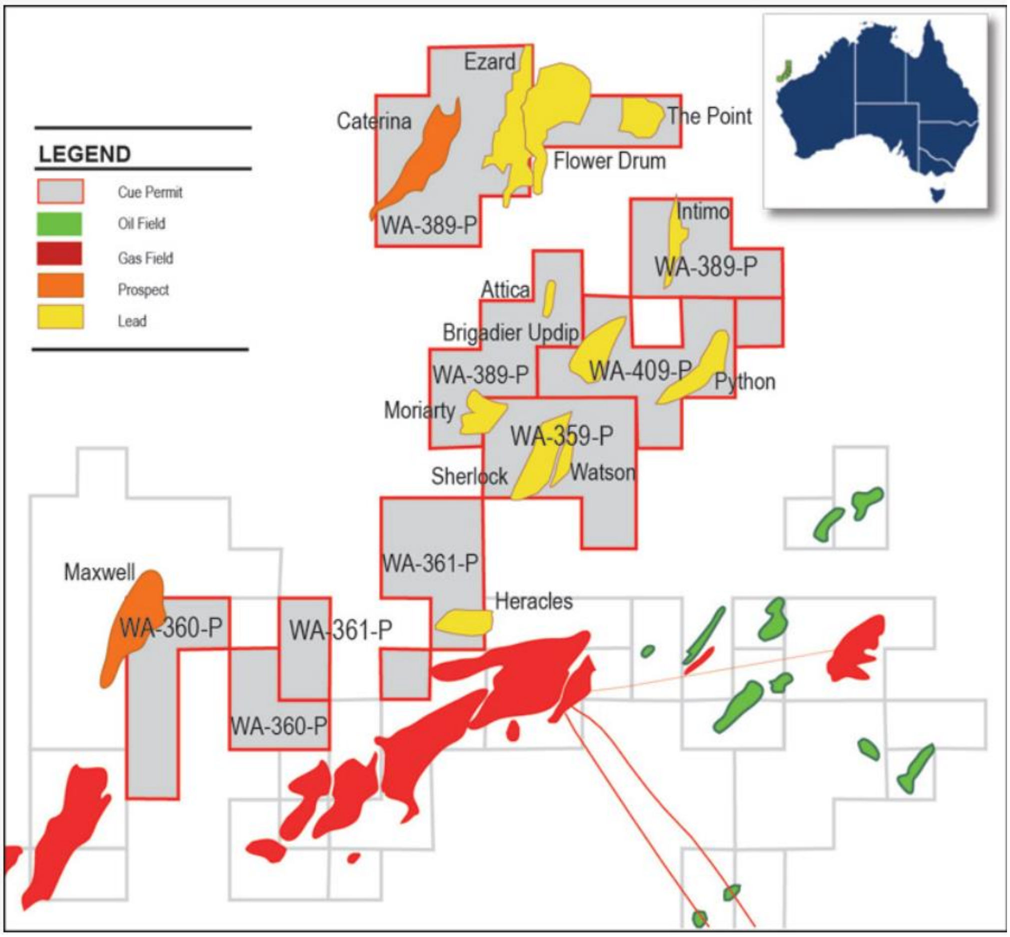


Figure 7-1: Cue exploration permits, Carnarvon Basin, WA

The Northern Carnarvon Basin evolved from a broad intracontinental basin in the late Paleozoic, through syn-rift sub-basins in the Jurassic, to a passive margin carbonate shelf in the Cenozoic[7].

Two petroleum systems are considered to be the source of the majority of the commercially developed accumulations within the basin.

The main gas-prone source rocks in the Barrow, Dampier and Exmouth sub-basins are inferred to be the Triassic fluvio-deltaic sediments of the Mungaroo Formation, Figure 7-2 with an additional contribution from the overlying Lower to Middle Jurassic marine and deltaic Murat Siltstone and Athol/Legendre formations. Geochemical studies indicate that the gas accumulations of the Rankin Platform accessed these Triassic sources, as well as Lower–Middle Jurassic sources in the adjacent Barrow and Dampier sub-basins. The giant gas accumulations of the Exmouth Plateau are inferred to have been charged from deeply buried coal and carbonaceous claystone in the Mungaroo Formation although a contribution from the Locker Shale has not been discounted.

[7] Australian Government Department of Industry Geoscience Australia, Regional Geology of the Northern Carnarvon Basin. Offshore Petroleum Acreage Release 2014

The oil-prone 'Dingo–Mungaroo/Barrow' Petroleum System is restricted to the Exmouth, Barrow and Dampier sub-basins, and is principally sourced from the Upper Jurassic Dingo Claystone.

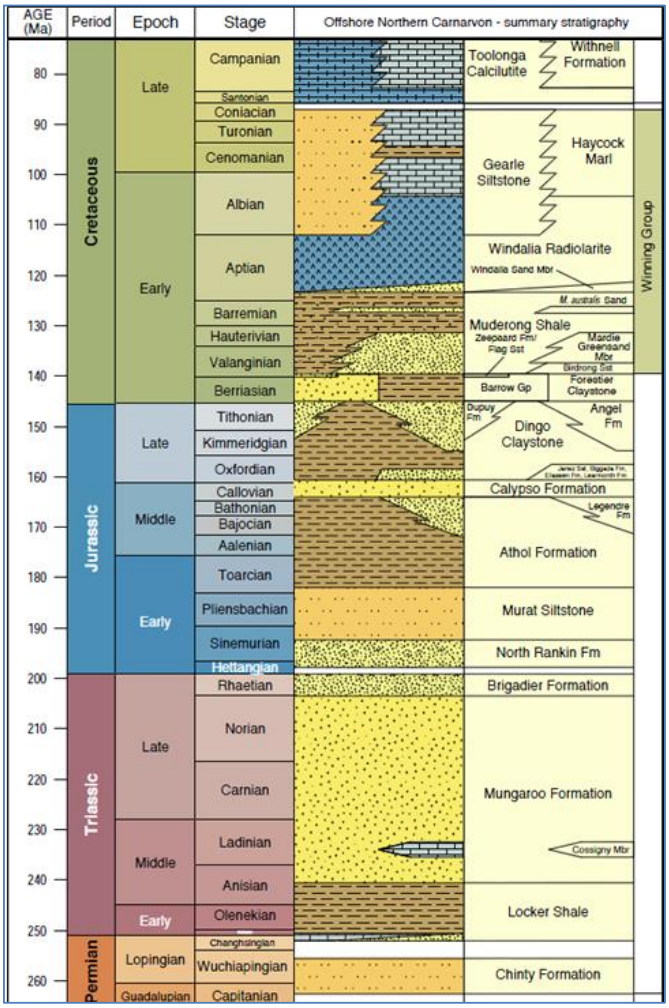


Figure 7-2: Northern Carnarvon Basin stratigraphic column

Reservoir rocks are dominated by fluvio-deltaic and marginal marine sandstones, including those within the Triassic Mungaroo Formation, the Bajocian–Callovian Legendre Formation in the Beagle and Dampier sub-basins, and the Berriasian–Valanginian Barrow Group in the Barrow and Exmouth sub-basins and the Exmouth Plateau. Most hydrocarbon discoveries within the basin are hosted by reservoirs beneath the Lower Cretaceous Muderong Shale, which forms an effective regional seal and has contributed to the high exploration success rate

In addition, intraformational seals result in stacked hydrocarbon-bearing reservoirs. Gas accumulations on the Rankin Platform are top-sealed by a combination of the regional seal and intraformational claystones. Significant intraformational seals occur within the Berriasian–Valanginian Barrow Group, Forestier Claystone and equivalents, the Toarcian–Callovian Athol and Legendre formations, and the Triassic Mungaroo Formation.

The main structural trap styles in the basin are horsts, tilted fault blocks, drapes and fault roll-over anticlines. Stratigraphic trap styles include basin-floor and turbidite fans, unconformity pinch-outs and onlaps. Structural compartmentalisation of the basin has resulted in complex trap evolution and charge histories.

Hydrocarbon generation from the Dingo Claystone commenced in the Exmouth Sub-basin and southern parts of the Barrow Sub-basin in the Early Cretaceous with the loading of the Barrow Delta. Hydrocarbon generation from potential Lower to Middle Jurassic source rocks in the Beagle Sub-basin began prior to deposition of the Lower Cretaceous Muderong Shale regional seal; however the loading of a major Cenozoic carbonate wedge has driven a pulse of maturation, with a higher chance of remaining trapped The main phase of generation in the Dampier Sub-basin was also in response to the progradation of the Cenozoic carbonate shelf. On the Exmouth Plateau, peak gas generation from the Mungaroo Formation is currently expected at depths of over 5000 m below the sea floor.

7.1. WA-359-P Cue 100%

The permit covers an area of 645 km^2 in two parts covering 8 graticular blocks. In 2014 Apache decided to withdraw from the permit and Cue assumed Operatorship and a 100% working interest. Under NOPSEMA regulations Cue is not a qualified offshore Operator and is therefore seeking a NOPSEMA qualified farmin partner to enable future drilling activities within the permit.

The permit was renewed in October 2012 for 5 years and will expire in October 2017. Work commitments include a single exploration well to be drilled in Q4 2015 pending finding a suitably qualified farminee. Additional commitments are minor and include geotechnical studies.

The permit and adjacent WA-409-P permit is covered by high quality 3D seismic (Zeebries 3D survey) which was reprocessed in 2014. The original multi-client data was processed to PSTM. The primary PSDM processing objectives which used broadband processing were to better define sand-probability volumes; produce a high resolution velocity model; remove remnant multiples; prove imaging.

The primary targets within the permit are high permeability reservoirs below the Base Cretaceous Unconformity, Figure 7-3. Secondary targets are Lower Jurassic and Triassic sandstones, Figure 7-3 and Figure 7-4. Source rocks are oil-prone Jurassic claystones within the neighbouring Victoria Syncline .Regional Early Cretaceous claystones are present across the permit which act as a top seal.

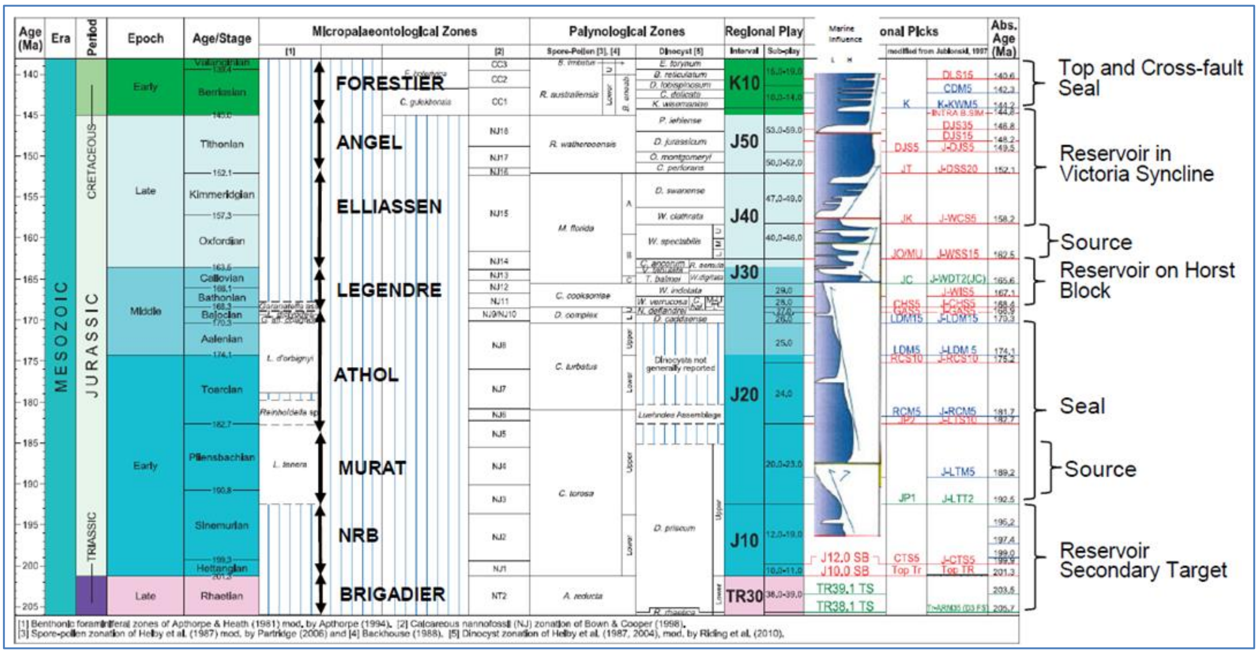


Figure 7-3: Northern Carnarvon primary petroleum system

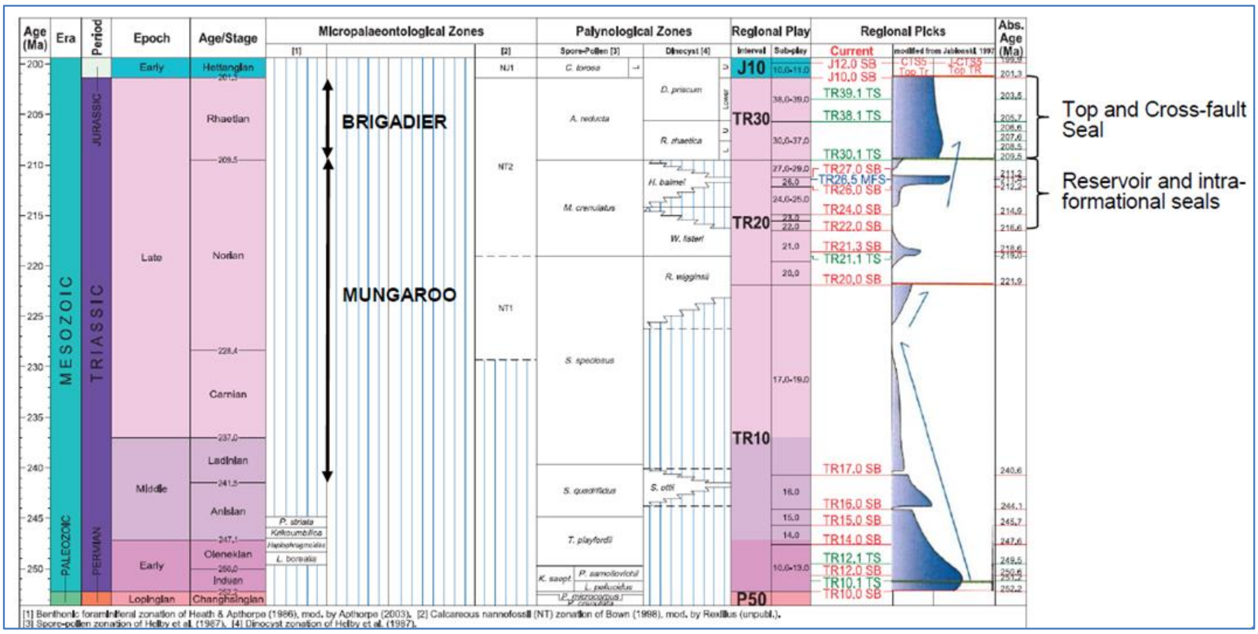


Figure 7-4: Northern Carnarvon secondary petroleum system

The major prospect is Sherlock which is a combination structural and stratigraphic trap. 6 leads have also been identified, Figure 7-5. Lead B/C is named Mycroft, lead D is called Hudson and lead E is Alder and lead I is Moran. Andromeda East is the only lead identified in the north eastern sub-block.

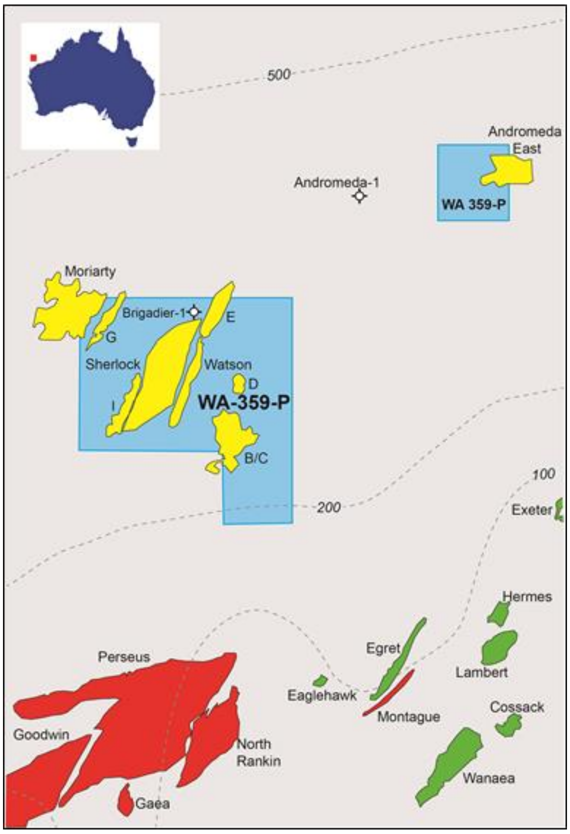


Figure 7-5: Location of Sherlock prospect and additional leads in WA-359-P

The Brigadier horst structure on which the Sherlock prospect is located has been remapped from the Zeebries PSDM reprocessed volume. The reprocessed volume has significantly improved data quality compared to the original PSTM processed volume that was originally used to define the prospect. This has allowed sequence boundaries to be mapped with confidence and the structural spill point beneath the regional seal (combined K10 and J50) of the Sherlock prospect to be estimated at 3035 mSS. Seismic amplitudes and sequence isochron mapping have been used to define volumetric limits. The Improved mapping of faults has provided greater confidence in fault seal analysis study results. The up-dip fault seal risk is deemed to be low.

Cue's probabilistic volumetric input parameters have been reviewed and are supported. Gross P50 STOIIP and prospective resources are estimated to be 253 MMstb and 51 MMstb respectively.

Cue currently assigns a 25% geological chance of success to the prospect as a result of the improved seismic imaging from the PSDM reprocessed dataset. Note that Cue uses a six element risking method compared to the usual 4 elements (reservoir, seal, charge and trap) hence the POS values are quite conservative.

Follow up leads are Watson, Mycroft, Hudson, Alder and Moran shown in Figure 7-5 all have mid-late Jurassic sandstone reservoir targets below the Base Cretaceous Unconformity. Some play dependency exists so that failure at Sherlock could increase the risk for some of these leads.

Sherlock has been adopted as the first development in WA-359/389 and is assumed to form a subsea hub tied back to Exeter Mutineer FPSO.

7.2. WA-389-P Cue 40%

WA-389-P consists of 3 sub-blocks, Figure 7-6. The southern sub-blocks are contiguous with Cue's WA-359-P and WA-409-P permits. BHP is the Operator and Cu's interest is 40%

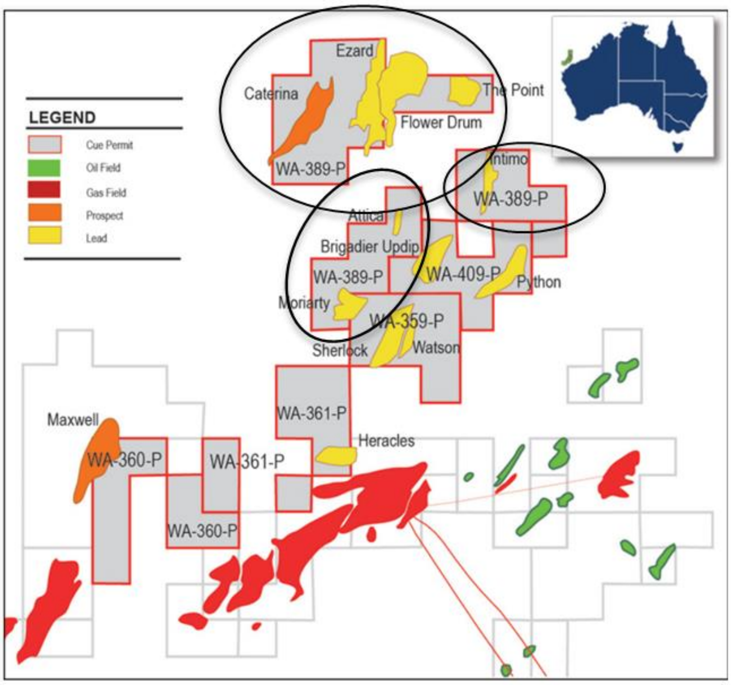


Figure 7-6: WA-389-P prospects and leads map

7.2.1. Exploration Potential

One prospect and several leads have been identified in WA-389-P, the outlines of which are shown in Figure 7-6.

The Caterina prospect is a large gas prone 3-way dip closure, refer Figure 7-7, located in the northern sub-block. It is covered by 3D seismic which is currently being reprocessed by the Operator.

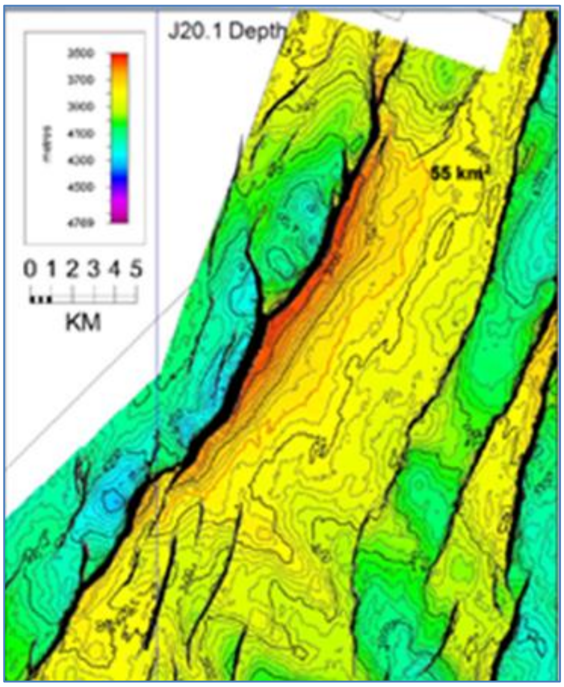


Figure 7-7: Caterina prospect J20.1 depth structure map

The Top Mungaroo Formation is considered to be the primary objective, however additional viable target reservoirs include the North Rankin Beds (NRB) and Brigadier Formation.

Cue currently estimates the best estimate prospective GIIP to be 1.9 TCF and prospective resource 1.4 TCF. The geological chance of success is 13%. The relatively high risk is a result of the lack of amplitude conformance to structure (which is usually a good indicator for the presence of gas bearing sand). The risk profile and volumetric estimate is likely to change once the seismic dataset has been reprocessed and the seismic products are available for interpretation.

There is a year 5 exploration commitment well in 2017 and it is likely that this will be a test of the Caterina structure.

Several follow up leads are also present and these are being reviewed by Cue's subsurface team. The results of the Caterina and Sherlock exploration wells will impact the prospectivity of these leads.

7.3. WA-360-P Cue 37.5%

WA-360-P covers an area of 643 km^2, Figure 7-8 MEO is the Operator and Cue has a 37.5 % interest. The Permit expires on 5th March 2017. Existing commitments include minor geotechnical studies, Table 7-1.

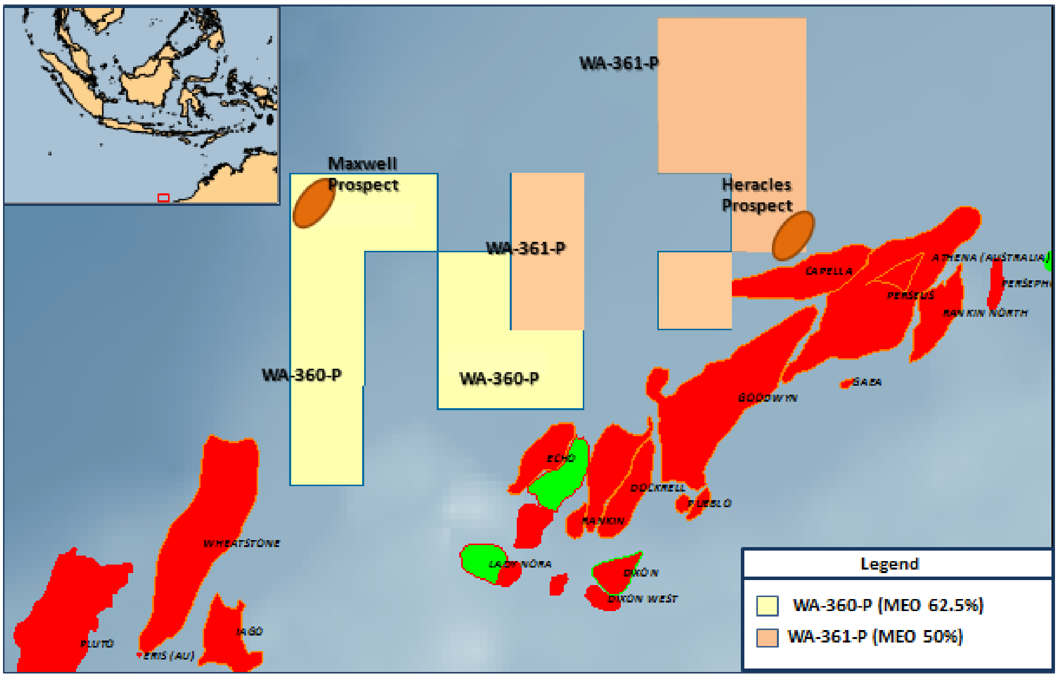


Figure 7-8: WA-360-P location

Table 7-1: WA-360-P work program commitments

	Permit Year	Permit Year Starts	Permit Year Ends	WA-360-P Program
Primary Term	1	06/03/12	06/03/13	Purchase On-Permit Foxhound 3D (363km^2)
	2	06/03/13	06/03/14	648km^2 3D Seismic Reprocessing (full permit coverage)
	3	06/03/14	06/03/15	Geotechnical Studies
Secondary Term	4	06/03/15	06/03/16	Geotechnical Studies
	5	06/03/16	06/03/17	One (1) Exploration Well
	6	06/03/12	06/03/13	Purchase On-Permit Foxhound 3D (363km^2)

7.3.1. Exploration potential

The Maxwell conceptual lead is the only lead currently identified in WA-360-P, Figure 7-9.

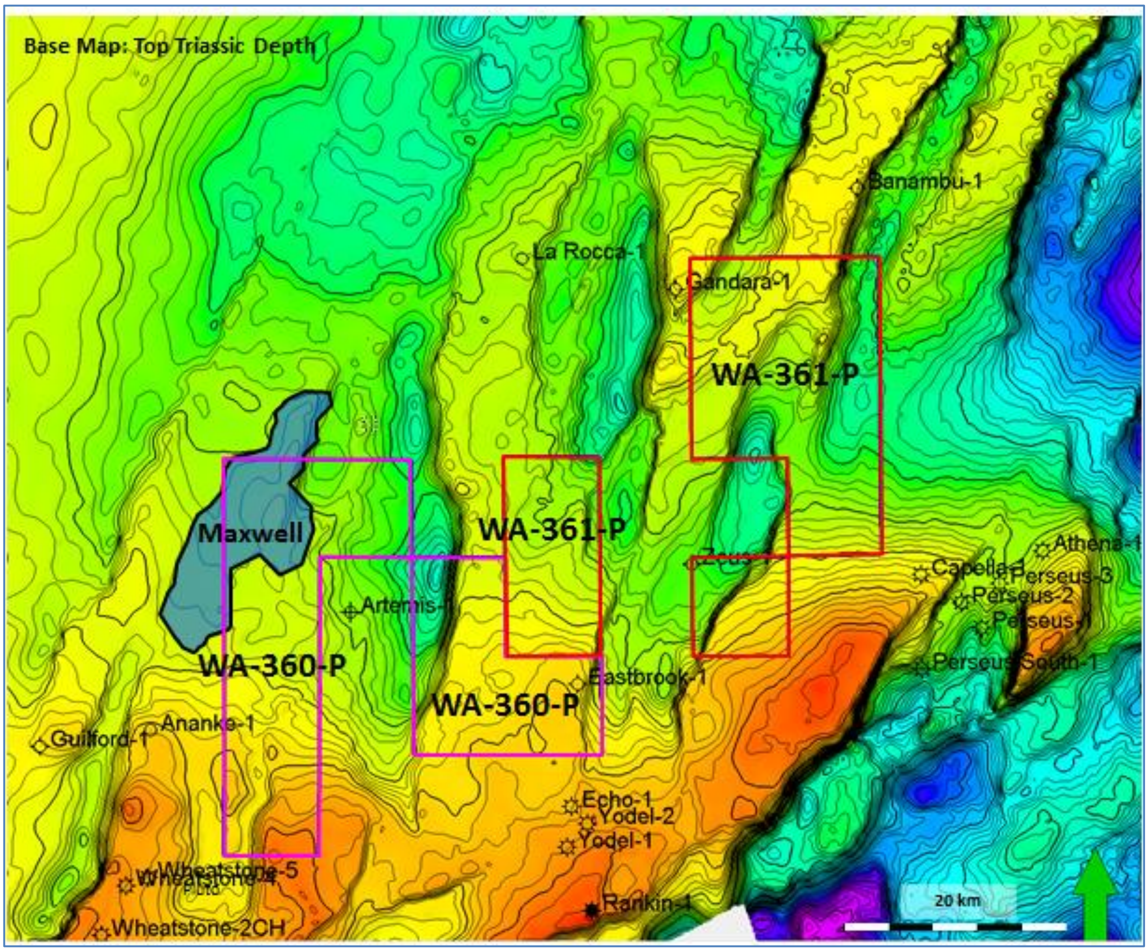


Figure 7-9: Maxwell prospect location, WA-360-P

Maxwell is a gas prone stratigraphic-structural closure containing stacked Dingo, Eliassen and Calypso reservoirs mapped above the Wheatstone gas water contact (GWC) and potentially connected to the Wheatstone prospect via the Dingo sandstone, Figure 7-10.

The Dingo sandstone has been penetrated at Wheatstone where it is gas charged and in communication with Triassic reservoirs. The Dingo sandstone was also penetrated at Artemis-1 below the Wheatstone GWC.

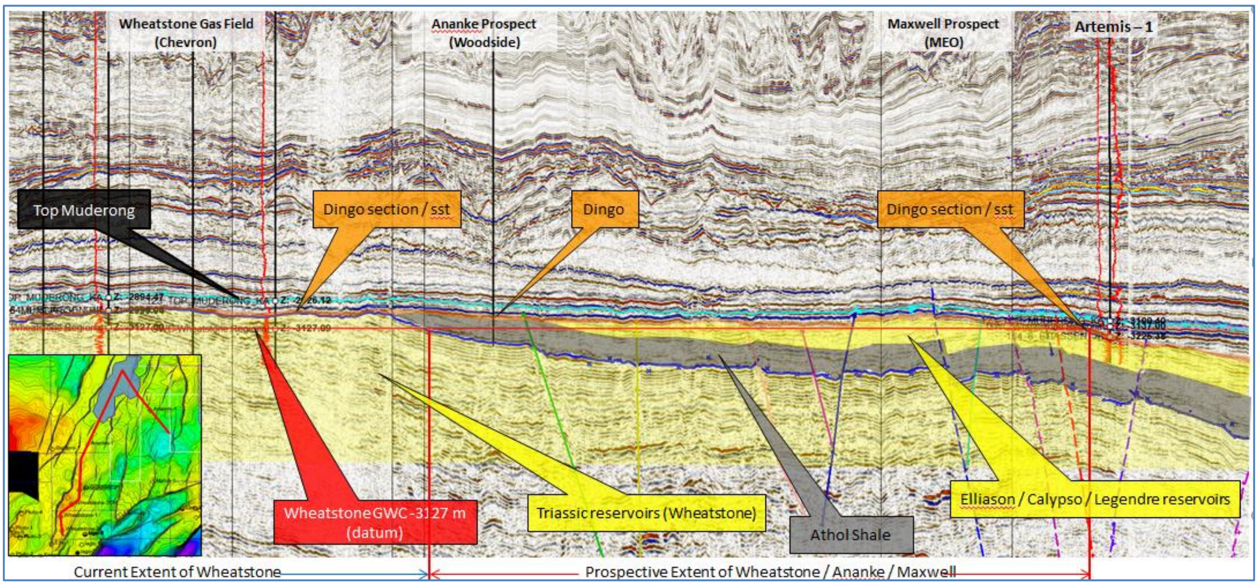


Figure 7-10: Maxwell prospect – Jurassic gas play

Depth conversion is key to the prospect which is impacted by significant time distortion under the slope of the seafloor. It is a high risk stratigraphic concept play.

There are no drillable prospects within the permit and prospectivity is considered to be low.

7.4. WA 361P Cue 15%

WA-361-P covers an area of 644 km^2. MEO is the Operator and Cue has a 15% interest. The permit expires on 30th Jan 2016. Existing commitments minor geotechnical studies, Table 7-1.

Table 7-2: WA-360-P work program commitments

	Permit Year	Permit Year Starts	Permit Year Ends	WA-361-P Program
Primary Term	1	01/02/11	31/01/12	Geotechnical Studies
	2	01/02/12	31/01/13	Geotechnical Studies, 150Km^2 3D Seismic
	3	01/02/13	31/01/14	Geotechnical Studies, 3D Seismic Interpretation
Secondary Term	4	01/02/14	31/01/15	Geotechnical Studies, One (1) Exploration Well
	5	01/02/15	31/01/16	Geotechnical Studies
	6	01/02/11	31/01/12	Geotechnical Studies

Table 7-3 shows the leads and prospects identified in WA-361-P which are described in Table 7-3. Recent work by the Operator has shown the West Zeus lead to be a depth conversion artefact and therefore it will not be pursued.

There are no drillable prospects within the permit and prospectivity is considered to be low.

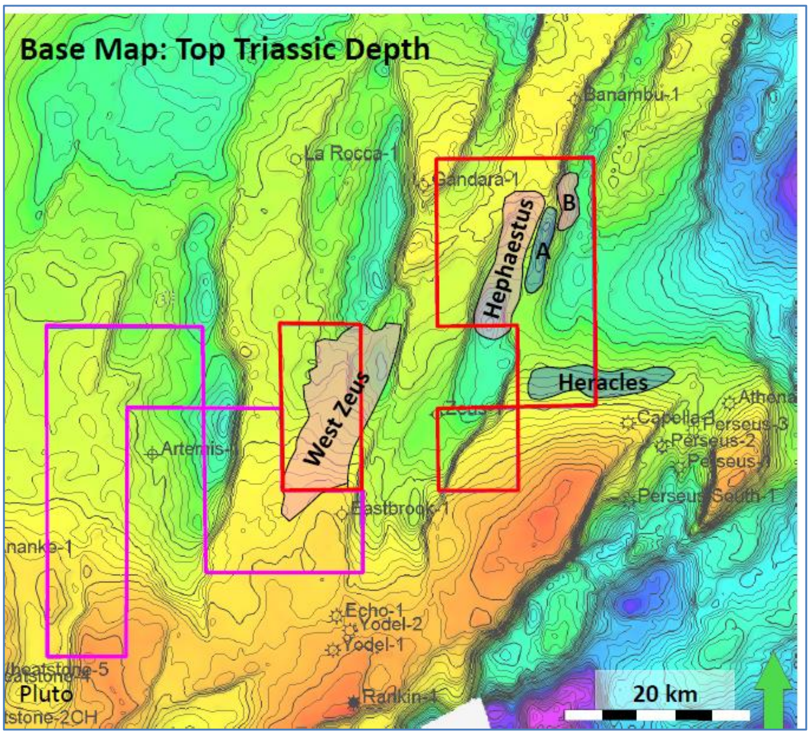


Figure 7-11: WA-361-P concepts and leads map

Table 7-3: WA-361 concepts and leads summary table

Name	Status	Play Type	Characteristics	Comments
Heracles	Lead	Stratigraphic Trap	Displaced LST unit of Legendre Fm, top sealed by Calypso/Forestier/Muderong shales, base sealed by Legendre Fm shales, found on the southern margin of the Keast Graben.	Trap geometries suggest unlikely base seal and connection between HST and LST Legendre sands. No amplitude anomaly.
Hephaestus	Concept	Stratigraphic Trap	The same displaced Legendre LST unit with the same geometries as Heracles but found on the northern margin of the Keast Graben.	The same uncertainty with base seal exists here as in Heracles. No amplitude anomaly.
Lead A	Lead	High Horst Block	~100 Bcf horst block, North Rankin reservoirs with Athol shale cross-fault seals on both sides, Brigadier Fm as base seal.	Needs to seal faults on both sides of horst as well as seal at northern peak of structure. Amplitude small.
Concept B	Concept	Low-side Roll	Low-side roll caused by fault-bend-folding. Legendre reservoir, Calypso/Forestier/ Muderong top seal, Athol shale cross-fault seal.	Relying on uplifted Athol shale in Lead A for cross-fault seal. Without Athol shale, we have Legendre against Legendre.
West Zeus	Concept	4-way dip closures	A small 4-way closure at identified at Muderong Fm level. Cannot really be seen at Nth Rankin Fm level.	No structure in TWT & possible depth conversion artifact. No structural reason for a 4-way closure to exist at this location.

7.5. WA-409-P Cue 100%

The two primary exploration prospects/leads in WA-409-P are Brigadier Updip and Python both of which are covered by the Zeebreis 3D seismic survey which was reprocessed at a budget cost of $1 million in 2014. The objectives of the reprocessing project are described in section 7.1.

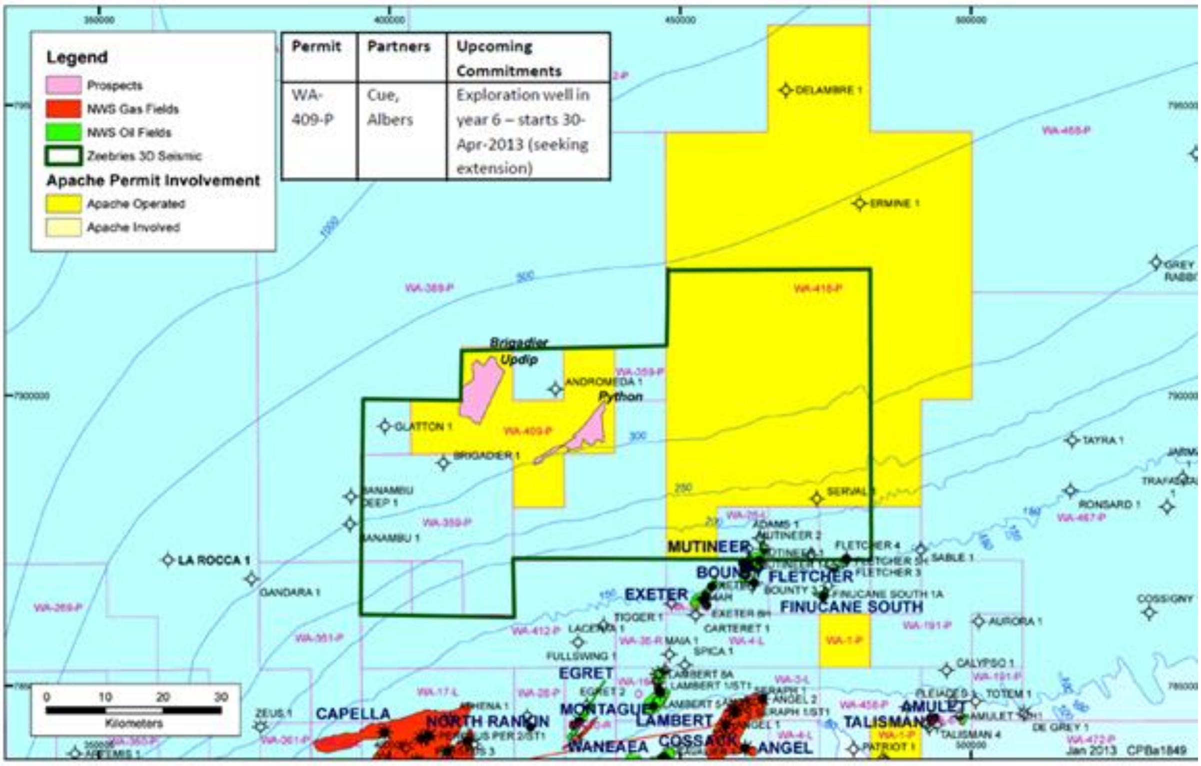


Figure 7-12: Brigadier Updip prospect and Python lead WA-409-P and WA- 359-P

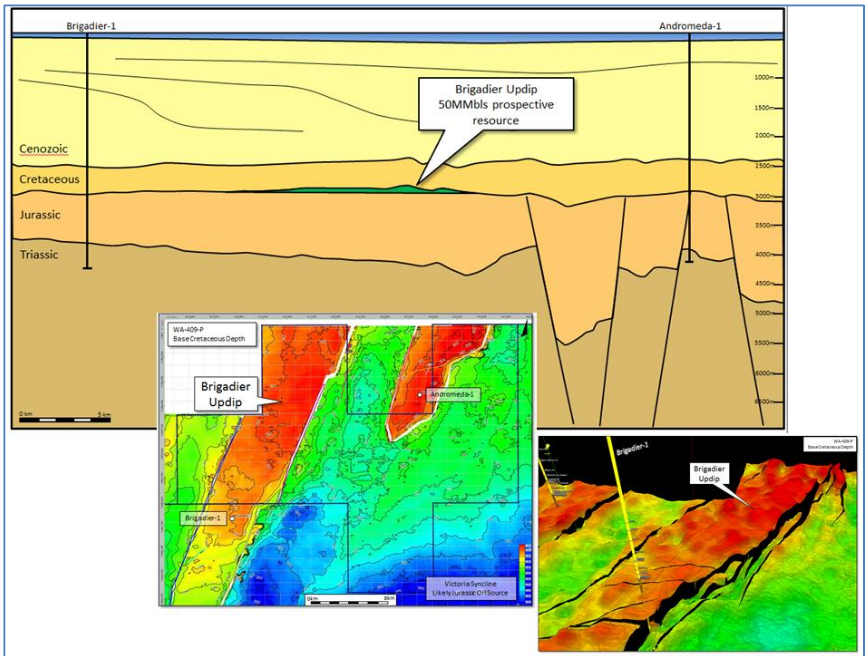


Figure 7-13: Brigadier Updip prospect

The Operator's P50 prospective resource for the Brigadier Updip prospect is 17.7 MMstb.

Lateral Seal is a risk as the Muderong has been faulted and down-thrown leaving juxtaposition with Late Cretaceous carbonates and siltstones. Reservoir thickness relies on an expanded Legendre section (compared to Brigadier-1). The expansion would have left the higher N:G Upper Legendre reservoir preserved under the Base Cretaceous Unconformity. Source and migration risks are the presence of source rock and migration across faults. Geological chance of success (POS) is estimated to be 11%.

Ongoing work to mature the Python lead includes:

- 3D prestack seismic inversion, rock physics modeling, and QI to help identify the likely lithology of the North Rankin Fm interval.
- A regional well-based study to better estimate porosity in North Rankin Fm at Python Lead.
- Creation of a regional hydrocarbon charge model to examine the likelihood of oil in the North Rankin Fm.

Prospective resource estimates and risking will be carried out on completion of this work.

8. Exploration valuation

8.1. Exploration Portfolio

The dimensions and details of Cue's exploration asset portfolio at the date of this report is summarised in Table 8-1 below:

Table 8-1: Cue Energy Resources Ltd Petroleum Permits at 20 February 2015

Permit Name	Gross Area sq.km	Operator (Parent Company shown)	Cue Interest	Permit start	Permit end	Work commitments remaining	
						Firm	Contingent
New Zealand							
PMP 38160	80	OMV	5%	2-Dec-05	1-Dec-27	NA	NA
PEP 51313	819	OMV	14%	30-Jul-09	29-Jul-21	G&G	G&G
PEP 54865	2475	Todd Energy	20%	11-Dec-12	10-Dec-17	285 sq-km 3D	1 well before Dec 2016
PEP 51149	217	Todd Energy	20%	23-Sep-08	22-Sep-18	1 well (end 2015)	30km 2D seismic (by Sept 2017), 1 well (by Sept 2018)
Indonesia							
Sampang PSC	534.5	Santos	15%			NA	NA
Mahakam Hilir PSC	275	Cue Energy (Pending Approval)	100% (pending Government of Indonesia Approval)	13-Nov-08	12-Nov-15	1 well	NA
Mahato PSC	5637	Texcal Mahato	12.5% (pending GOI Approval)	20-Jul-12	19-Jul-18	1 well, 200km 2D seismic (Jul 2015)	1 Well (July 2016-Jul 2017), 1 well (July 2017-July 2018), G&G studies
Australia							
WA-359-P	645	Cue Energy	100%	26-Oct-12	25-Oct-17	1 well (Oct 2014-Oct 2015)	Geotechnical Studies
WA-360-P	643	MEO	37.50%	6-Mar-12	5-Mar-17	G&G studies	Geotech studies, 1 Well (march 2016-Mar 2017)
WA-361-P	644	MEO	15%	31-Jan-11	30-Jan-16	Seismic Reprocessing (underway)	NA
WA-389-P	1939	BHP Billiton	40%	9-Oct-13	8-Oct-18	Seismic Reprocessing	Geotech Studies, 1 well (Oct 2017-Oct 2018)
WA-409-P	565	Cue Energy	100%		29-Apr-15	NA	NA

8.2. Methodology

Under the current oil price environment, which has resulted from the halving of the oil price from June 2014, many companies in the upstream oil and gas industry have been reducing their capital expenditure budgets, including for exploration. The value of Cue's exploration asset portfolio has been assessed in this context.

As many of Cue's exploration interests are in lightly explored, immature permits, RISC has relied on farm-in promote multiples of exploration well or seismic expenditures to determine the value range of the permits. Unrisked success case economic values of prospects at US$60/bbl, US$80/bbl and US$100/bbl have been used to determine the initial attractiveness of prospects within a permit.

Permits with no drillable prospects, or which have been assessed as high risk or with relatively low prospectivity, have initially been valued at the level of Cue's future cost commitments. However, the quantum of these future commitments has then been deducted to determine the net value of the permits on a regional and portfolio basis.

For permits with marginal prospects, the high values have been based on applying typical farm-in promote multiples on Cue's past costs and future commitments. As result, this has led to a widening in the valuation range, away from a bell-curve type distribution. However, these value distributions reflect the very nature of exploration work programmes, which include the possibilities for more dispersed high-side outcomes.

For the more prospective permits, typical farm-in promote multiples were applied to Cue's past costs and future commitments to determine low, mid and high values for these permits. (Note: For the Mahakam Hilir PSC, RISC has only considered the past costs associated with the NS prospect, and not the failed NU prospect).

8.3. New Zealand

Cue has two offshore and one onshore permit in the Taranki Basin.

The onshore permit PEP 51149 is in a lightly explored part of the basin. A prospect with a shallow oil target and a deep gas target has been identified.

The Whio-1 well in the offshore permit PEP 51313 has downgraded all of the prospects in that permit.

Two prospects have been identified in the other offshore permit PEP 54865. A commitment 3D seismic survey has been deferred to 2016. There is also a contingent obligation for a well to be drilled by end-2016.

Table 8-2 summarises the values estimated for these permits.

Table 8-2: Value of Cue's New Zealand exploration permits

Permit	Cue Equity Interest %	Status	Low Value A$M	Mid Value A$M	High Value A$M	Comments
PEP 51149	20.0%	Onshore prospect in lightly explored area, with shallow oil target and deep gas target	5.9	6.9	9.9	Low, mid and high values based on 1:1, 1.5:1 and 2:1 times carry of well
PEP 51313	14.0%	All prospects in block downgraded after failure of Whio-1	0.4	0.4	0.4	Low, mid & high values based on future commitments after tax.

PEP 54865	20.0%	3D seismic commitment deferred 2016	0.0	0.0	1.1	Low & mid values based on future commitments after tax. High value is based on farm-out promote of 1.5:1 carry on seismic commitment prior to a decision on the contingent well obligation
Total Value of New Zealand exploration assets			6.3	7.4	11.4	
Less future firm commitments			-4.4	-4.4	-4.4	
Net value of New Zealand exploration assets			**1.9**	**2.9**	**6.9**	

8.4. Indonesia

Of Cue's Indonesian assets, the offshore Sampang PSC has limited prospectivity with the Jeruk discovery remaining technically challenging and uneconomic. The Mahakam Hilir PSC in the onshore Kutei Basin in Kalimantan has a drill ready prospect, which with seal and trap uncertainties is fairly high risk. The Mahato PSC in the onshore Central Sumatra Basin is highly prospective, with some 20 prospects and leads having been identified.

The table below summarises the value ranges of these assets.

Table 8-3: Value of Cue's Indonesia exploration permits

Permit	Cue Equity Interest %	Status	Low Value A$M	Mid Value A$M	High Value A$M	Comments
Sampang PSC	15.0%	Jeruk static resources are uneconomic due to remaining significant, technically-challenging estimating uncertainties	0.3	0.3	0.3	Low, mid & high values based on future commitments after tax.
Mahakam Hilir PSC	100.0%	Single onshore prospect	13.5	17.7	26.1	Low, mid and high values based on 1.25:1, 1.5:1 and 2:1 times carry of seismic reprocessing and well
Mahato PSC	12.5%	Several prospects onshore.	5.6	7.0	8.4	Low, mid and high values based on 2:1, 2.5:1 and 3:1 times carry of seismic and wells
Total Value of Indonesian exploration assets			19.4	25.0	34.8	
Less future firm commitments			-14.1	-14.1	-14.1	
Net value of Indonesian exploration assets			**5.3**	**10.9**	**20.7**	

8.5. Australia

Cue's Australian permits are located in the relatively deep water (>200 m) offshore northern Carnarvon Basin of Western Australia. Two prospects in two of the permits have been upgraded. The remaining permits either have prospects whose commercialization opportunities are conditional on these two prospects being successful, or do not have drillable prospects identified.

The table below summarises the values of these permits.

Table 8-4: Value of Cue's Australia exploration permits

Permit	Cue Equity Interest %	Status	Low Value A$M	Mid Value A$M	High Value A$M	Comments
WA-359-P	100.0%	Sherlock prospect has been upgraded. Permit is being farmed-out. Commitment well due by end of 2015	0.7	0.7	7.7	Low & mid value based on future commitments after tax. High value is based on farm-out promote of 1.1:1 carry on high cost commitment well under current oil price environment
WA-360-P	37.5%	No drillable prospects	0.2	0.2	0.2	Low, mid & high values based on future commitments after tax and very little prospect of farm-out under current oil price environment
WA-361-P	15.0%	No drillable prospects	0.0	0.0	0.0	Low, mid & high values based on future commitments after tax and very little prospect of farm-out under current oil price environment
WA-389-P	40.0%	Main gas prospect, Caterina, has been upgraded. Commitment well due in 2017	2.4	2.4	5.3	Low & mid value based on future commitments after tax. High value based on farm-out promote of 1.1:1 carry on high cost commitment well under current oil price environment
WA-409-P	100.0%	Apache has withdrawn from permit. Oil prospect conditional on Sherlock prospect success	0.6	0.6	0.6	Low, mid & high values based on future commitments after tax and very little prospect of farm-out under current oil price environment
Total Value of Australian exploration assets			3.9	3.9	13.8	
Less future firm commitments			-3.9	-3.9	-3.9	
Net value of Australian exploration assets			**0.0**	**0.0**	**9.9**	

8.6. Summary

RISC has assessed the value of Cue's individual exploration interests using the value of the work program and farm-in promote multiples. The sum of our low, mid and high estimates of the value of the individual permits, net of future firm commitment expenditures, are summarised in Table 8-5 below.

Table 8-5: Exploration valuation - Cue Energy's net working interest

Area	Fair Market Value, A$ million		
	Low	Mid	High
New Zealand	1.9	2.9	6.9
Indonesia	5.3	10.9	20.7
Australia	0.0	0.0	9.9
Total	**7.2**	**13.8**	**37.5**

The aggregated mid-value of each of the exploration assets has been assessed at A$ 13.8 million, while the low and high value estimates are A$ 7.2 million and A$ 37.5 million, respectively. As the low and high values of the exploration assets portfolio have been derived by the arithmetic addition of the individual asset low and high values, respectively, they represent the possible extremes of the exploration value envelop. While farmees into the individual permits could value the assets at either end of the value range assessed, it is unlikely that potential buyers of the exploration asset portfolio would value all of the assets at either all of the low or all of the high estimated extremes. Their own assessments of individual permits will span the low, mid or high outcomes based on factors including: their strategic objectives and region or geological basin focus; assessment of an asset's prospectivity and associated geological risks; the fiscal and regulatory framework applicable to the asset; accessibility of commercialisation routes, including markets and infrastructure, for each asset; equity interests, operator capability and joint venture partners in each asset.

Consequently, RISC assesses the value of Cue's exploration asset portfolio to a single buyer as lying between A$10 million and A$ 20 million.

9. Declarations

9.1. Qualifications

RISC is an independent oil and gas advisory firm. All of the RISC staff engaged in this assignment are professionally qualified engineers, geoscientists or analysts, each with many years of relevant experience and most have in excess of 20 years.

The preparation of this report has been supervised by Mr. Geoffrey Barker, RISC Partner. He has over thirty years of global experience in the upstream hydrocarbon industry, with extensive expertise in the areas of asset valuation, business strategies, evaluation of conventional and non-conventional petroleum (coal seam gas and tight gas), due diligence assessment for mergers, acquisitions and project finance requirements and reserves assessment/certification and preparation of Independent Technical Specialist reports. Mr. Barker is a Past Chairman of the SPE WA Section, a past member of the SPE International's Oil and Gas Reserves Committee 2007-2009, and is a co-author of the Guidelines for Application of the Petroleum Resources Management System published by the SPE in November 2011 (Chapter 8.5 Coal Bed Methane). Mr Barker is a Member of the Society of Petroleum Engineers (SPE), and holds a BSc (Chemistry), Melbourne University, 1980 and a M.Eng.Sc (Pet Eng), Sydney University, 1989 and is a qualified petroleum reserves and resources evaluator (QPPRE) as defined by ASX listing rules.

RISC was founded in 1994 to provide independent advice to companies associated with the oil and gas industry. Today the company has approximately 40 highly experienced professional staff at offices in Perth and Brisbane, Australia and London, UK. We have completed over 1500 assignments in 68 countries for nearly 500 clients. Our services cover the entire range of the oil and gas business lifecycle and include:

- Oil and gas asset valuations, expert advice to banks for debt or equity finance;
- Exploration/Portfolio management;
- Field development studies and operations planning;
- Reserves assessment and certification, peer reviews;
- Gas market advice;
- Independent Expert/Expert Witness;
- Strategy and corporate planning.

9.2. VALMIN Code

This Report has been prepared by RISC. This Report has been prepared in accordance with the Code for the Technical Assessment and Valuation of Mineral and Petroleum Assets and Securities for Independent Expert Reports 2005 Edition ("The VALMIN Code") as well as the Australian Securities and Investment Commission (ASIC) Regulatory Guides 111 and 112.

9.3. Petroleum Resources Management System

In the preparation of this Report, RISC has complied with the guidelines and definitions of the Petroleum Resources Management System approved by the Board of the Society of Petroleum Engineers in 2007 (PRMS).

9.4. Report to be presented in its entirety

RISC has been advised by Cue that this report will be presented in its entirety without summarisation.

9.5. Independence

This report does not give and must not be interpreted as giving, an opinion, recommendation or advice on a financial product within the meaning of section 766B of the Corporations Act 2001 or section 12BAB of the Australian Securities and Investments Commission Act 2001.

RISC is not operating under an Australian financial services licence in providing this report.

In accordance with regulation 7.6.01(1)(u) of the Corporations Regulation 2001. RISC makes the following disclosures:

- RISC is independent with respect to Cue and Grant Samuel and confirms that there is no conflict of interest with any party involved in the assignment;
- Under the terms of engagement between RISC and Cue for the provision of this report, RISC will receive a time-based fee, with no part of the fee contingent on the conclusions reached, or the content or future use of this report. Except for these fees, RISC has not received and will not receive any pecuniary or other benefit whether direct or indirect for or in connection with the preparation of this report;
- Neither RISC nor any of its personnel involved in the preparation of this report have any material interest in Cue or in any of the properties described herein;
- RISC has not provided advice to Cue specifically in relation to the Proposed Transaction.
- RISC has carried out the following assignments for Cue over the last 2 years:
  - Technical and due diligence of a producing oil field (subject confidential)
  - Technical review of onshore Australian petroleum properties (subject confidential)
  - Independent review of the reserves and resources of the Maari Field
  - Independent technical review of the Jeruk field, Indonesia
- The abovementioned assignments were undertaken as part of our normal independent consulting services, did not involve contingent payments and do not affect our ability to take an unbiased view of the assets.

9.6. Limitations

The assessment of petroleum assets is subject to uncertainty because it involves judgments on many variables that cannot be precisely assessed, including reserves, future oil and gas production rates, the costs associated with producing these volumes, access to product markets, product prices and the potential impact of fiscal/regulatory changes.

The statements and opinions attributable to RISC are given in good faith and in the belief that such statements are neither false nor misleading. In carrying out its tasks, RISC has considered and relied upon information obtained from Cue as well as information in the public domain.

The information provided to RISC has included both hard copy and electronic information supplemented with discussions between RISC and key Cue staff.

Whilst every effort has been made to verify data and resolve apparent inconsistencies, we believe our review and conclusions are sound, but neither RISC nor its servants accept any liability, except any liability which cannot be excluded by law, for its accuracy, nor do we warrant that our enquiries have revealed all of the matters, which an extensive examination may disclose.

In particular, we have not independently verified property title, encumbrances or regulations that apply to this asset(s). We have not independently confirmed the status of the permit titles. RISC has also not audited the opening balances at the economic evaluation date of past recovered and unrecovered development and exploration costs, undepreciated past development costs and tax losses.

We believe our review and conclusions are sound but no warranty of accuracy or reliability is given to our conclusions.

Our review was carried out only for the purpose referred to above and may not have relevance in other contexts.

9.7. Consent

RISC has consented to this report, in the form and context in which it appears, being included in the Independent Expert's Report prepared by Grant Samuel for Cue. Neither the whole nor any part of this report nor any reference to it may be included in or attached to any other document, circular, resolution, letter or statement without the prior consent of RISC.

This Report is authorised for release by Mr. Geoffrey Barker, RISC Partner dated 28 February 2015.

Geoffrey J Barker
Partner

Appendix 1: List of terms

The following table lists abbreviated terms, along with a brief definition, that are commonly used in the oil and gas industry and which may be used in this report.

Abbreviation	Definition
1P	Equivalent to Proved reserves or Proved in-place quantities, depending on the context.
1Q	1st Quarter
2P	The sum of Proved and Probable reserves or in-place quantities, depending on the context.
2Q	2nd Quarter
2D	Two Dimensional
3D	Three Dimensional
4D	Four Dimensional – time lapsed 3D in relation to seismic
3P	The sum of Proved, Probable and Possible Reserves or in-place quantities, depending on the context.
3Q	3rd Quarter
4Q	4th Quarter
AFE	Authority for Expenditure
Bbl	US Barrel
BBL/D	US Barrels per day
BCF	Billion (109) cubic feet
BCM	Billion (109) cubic meters
BFPD	Barrels of fluid per day
BOPD	Barrels of oil per day
BTU	British Thermal Units
BOE	barrels of oil equivalent (equivalent to 1 bbl oil, 1 bbl condensate, 1 bbl NGL, 6,000 scf gas)
BOEPD	US barrels of oil equivalent per day
BWPD	Barrels of water per day
°C	Degrees celsius
Capex	Capital expenditure
CAPM	Capital asset pricing model
CGR	Condensate Gas Ratio – usually expressed as bbl/MMscf
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent Resources are a class of discovered recoverable resources as defined in the SPE-PRMS.
CO2	Carbon dioxide
CP	Centipoise (measure of viscosity)
CPI	Consumer Price Index
DEG	Degrees

Abbreviation	Definition
DHI	Direct hydrocarbon indicator
Discount Rate	The interest rate used to discount future cash flows into a dollars of a reference date
DST	Drill stem test
E&P	Exploration and Production
EG	Gas expansion factor. Gas volume at standard (surface) conditions / gas volume at reservoir conditions (pressure & temperature)
EIA	US Energy Information Administration
EMV	Expected Monetary Value
EOR	Enhanced Oil Recovery
ESP	Electric submersible pump
EUR	Estimated ultimate recovery
Expectation	The mean of a probability distribution
F	Degrees Fahrenheit
FDP	Field Development Plan
FEED	Front End Engineering and design
FID	Final investment decision
FM	Formation
FPSO	Floating Production Storage and offtake unit
FWL	Free Water Level
FVF	Formation volume factor
GIIP	Gas Initially In Place
GJ	Giga (10^9) joules
GOC	Gas-oil contact
GOR	Gas oil ratio
GRV	Gross rock volume
GSA	Gas sales agreement
GTL	Gas To Liquid(s)
GWC	Gas water contact
H2S	Hydrogen sulphide
HHV	Higher heating value
ID	Internal diameter
IRR	Internal Rate of Return is the discount rate that results in the NPV being equal to zero.
JV(P)	Joint Venture (Partners)
Kh	Horizontal permeability
km2	Square kilometres
Krw	Relative permeability to water
Kv	Vertical permeability

Abbreviation	Definition
kPa	Kilo (thousand) Pascals (measurement of pressure)
Mstb/d	Thousand Stock tank barrels per day
LIBOR	London inter-bank offered rate
LNG	Liquefied Natural Gas
LTBR	Long-Term Bond Rate
m	Metres
MDT	Modular dynamic (formation) tester
mD	Millidarcies (permeability)
MJ	Mega (10^6) Joules
MMbbl	Million US barrels
MMscf(d)	Million standard cubic feet (per day)
MMstb	Million US stock tank barrels
MOD	Money of the Day (nominal dollars) as opposed to money in real terms
MOU	Memorandum of Understanding
Mscf	Thousand standard cubic feet
Mstb	Thousand US stock tank barrels
Mtpa	Millions of tons per annum
MPa	Mega (10^6) pascal (measurement of pressure)
mss	Metres subsea
MSV	Mean Success Volume
mTVDss	Metres true vertical depth subsea
MW	Megawatt
NPV	Net Present Value (of a series of cash flows)
NTG	Net to Gross (ratio)
ODT	Oil down to
GIIP	Original Gas In Place
STOIIP	Original Oil in Place
Opex	Operating expenditure
OWC	Oil-water contact
P90, P50, P10	90%, 50% & 10% probabilities respectively that the stated quantities will be equalled or exceeded. The P90, P50 and P10 quantities correspond to the Proved (1P), Proved + Probable (2P) and Proved + Probable + Possible (3P) confidence levels respectively.
PBU	Pressure build-up
PJ	Peta (10^{15}) Joules
POS	Probability of Success

Abbreviation	Definition
Possible Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. 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) which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.
Probable Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that 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.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations as defined in the SPE-PRMS.
Proved Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty 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. Often referred to as 1P, also as "Proven".
PSC	Production Sharing Contract
PSDM	Pre-stack depth migration
PSTM	Pre-stack time migration
psia	Pounds per square inch pressure absolute
p.u.	Porosity unit e.g. porosity of 20% +/- 2 p.u. equals a porosity range of 18% to 22%
PVT	Pressure, volume & temperature
QA/QC	Quality Assurance/ Control
rb/stb	Reservoir barrels per stock tank barrel under standard conditions
RFT	Repeat Formation Test
Real Terms (RT)	Real Terms (in the reference date dollars) as opposed to Nominal Terms of Money of the Day
Reserves	RESERVES are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised 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.
RT	Measured from Rotary Table or Real Terms, depending on context
SC	Service Contract
scf	Standard cubic feet (measured at 60 degrees F and 14.7 psia)
Sg	Gas saturation
Sgr	Residual gas saturation

Abbreviation	Definition
SRD	Seismic reference datum lake level
SPE	Society of Petroleum Engineers
SPE-PRMS	Petroleum Resources Management System, approved by the Board of the SPE March 2007 and endorsed by the Boards of Society of Petroleum Engineers, American Association of Petroleum Geologists, World Petroleum Council and Society of Petroleum Evaluation Engineers.
s.u.	Fluid saturation unit. e.g. saturation of 80% +/- 10 s.u. equals a saturation range of 70% to 90%
stb	Stock tank barrels
STOIIP	Stock Tank Oil Initially In Place
Sw	Water saturation
TCM	Technical committee meeting
Tcf	Trillion (10^{12}) cubic feet
TJ	Tera (10^{12}) Joules
TLP	Tension Leg Platform
TRSSV	Tubing retrievable subsurface safety valve
TVD	True vertical depth
US$	United States dollar
US$ million	Million United States dollars
WACC	Weighted average cost of capital
WHFP	Well Head Flowing Pressure
Working interest	A company's equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms.
WPC	World Petroleum Council
WTI	West Texas Intermediate Crude Oil