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2 July 2014

The Manager, Company Announcements
ASX Limited
Exchange Centre
20 Bridge Street
Sydney NSW 2000

Scheme of Arrangement – Independent Expert's Report

Horizon Oil Limited (**Horizon Oil**) announced on 29 April 2014 a proposed merger with Roc Oil Company Limited (**Roc Oil**) by way of a scheme of arrangement (**Scheme**).

In connection with the preparation of the Scheme Booklet to be despatched to Horizon Oil shareholders, Horizon Oil commissioned Deloitte Corporate Finance Pty Ltd to prepare an Independent Expert's Report.

Horizon's Independent Expert has concluded that the Scheme is in the best interests of Horizon Oil shareholders.

A copy of the Independent Expert's Report is attached to this announcement and will accompany the Scheme Booklet when distributed to Horizon Oil shareholders.

Further to the Company's update of 25 June 2014, the First Court Hearing is scheduled for 3 July 2014 for approval of the convening of the Scheme Meeting and, subject to the approval of the Court, the Scheme Booklet is scheduled to be despatched on or about 7 July 2014.

Yours faithfully

Michael Sheridan
Chief Financial Officer and Company Secretary

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Horizon Oil Limited

Independent expert's report and Financial Services Guide

1 July 2014

Financial Services Guide

What is a Financial Services Guide?

This Financial Services Guide (FSG) provides important information to assist you in deciding whether to use our services. This FSG includes details of how we are remunerated and deal with complaints.

Where you have engaged us, we act on your behalf when providing financial services. Where you have not engaged us, we act on behalf of our client when providing these financial services, and are required to give you an FSG because you have received a report or other financial services from us.

What financial services are we licensed to provide?

We are authorised to provide financial product advice and to arrange for another person to deal in financial products in relation to securities, interests in managed investment schemes, government debentures, stocks or bonds and related regulated emissions units (i.e., carbon) to retail and wholesale clients. We are also authorised to provide general financial product advice relating to derivatives to retail clients and personal financial product advice relating to derivatives to wholesale clients.

Our general financial product advice

Where we have issued a report, our report contains only general advice. This advice does not take into account your personal objectives, financial situation or needs. You should consider whether our advice is appropriate for you, having regard to your own personal objectives, financial situation or needs.

If our advice is provided to you in connection with the acquisition of a financial product you should read the relevant offer document carefully before making any decision about whether to acquire that product.

How are we and all employees remunerated?

We will receive a fee of approximately AUD 160,000 exclusive of GST in relation to the preparation of this report. This fee is not contingent upon the success or otherwise of the proposed transaction between Horizon Oil Limited and ROC Oil Company Limited (the Proposed Scheme).

Other than our fees, we, our directors and officers, any related bodies corporate, affiliates or associates and their directors and officers, do not receive any commissions or other benefits.

All employees receive a salary and while eligible for annual salary increases and bonuses based on overall performance they do not receive any commissions or other benefits as a result of the services provided to you. The remuneration paid to our directors reflects their individual contribution to the organisation and covers all aspects of performance.

We do not pay commissions or provide other benefits to anyone who refers prospective clients to us.

Associations and relationships

We are ultimately controlled by the Deloitte member firm in Australia (Deloitte Touche Tohmatsu). Please see www.deloitte.com/au/about for a detailed description of the legal structure of Deloitte Touche Tohmatsu.

What should you do if you have a complaint?

If you have any concerns regarding our report or service, please contact us. Our complaint handling process is designed to respond to your concerns promptly and equitably. All complaints must be in writing to the address below.

If you are not satisfied with how we respond to your complaint, you may contact the Financial Ombudsman Service (FOS). FOS provides free advice and assistance to consumers to help them resolve complaints relating to the financial services industry. FOS' contact details are also set out below.

The Complaints Officer	Financial Ombudsman Services
PO Box N250	GPO Box 3
Grosvenor Place	Melbourne VIC 3001
Sydney NSW 1220	info@fos.org.au
complaints@deloitte.com.au	www.fos.org.au
Fax: +61 2 9255 8434	Tel: 1300 780 808
	Fax: +61 3 9613 6399

What compensation arrangements do we have?

Deloitte Australia holds professional indemnity insurance that covers the financial services provided by us. This insurance satisfies the compensation requirements of the Corporations Act 2001 (Cth).

1 July 2014

Deloitte Corporate Finance Pty Limited, ABN 19 003 833 127, AFSL 241457 of 550 Bourke Street, Melbourne VIC 3000

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The Directors
Horizon Oil Limited
Level 7, 134 William Street
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NSW 2011

1 July 2014

Dear Directors

Independent expert's report

Introduction

On 29 April 2014, Horizon Oil Limited (Horizon or the Company), together with ROC Oil Company Limited (ROC), announced a proposal under which the two companies would merge by way of ROC acquiring all of the issued shares in Horizon via a scheme of arrangement (the Proposed Scheme). Horizon entered into a Merger Implementation Deed with ROC, agreeing to propose the scheme to Horizon shareholders (Horizon Shareholders).

If the Proposed Scheme is approved, Horizon Shareholders (other than ineligible foreign shareholders) will receive consideration of 0.724 ROC shares for every share held in Horizon at the "Record Date" (currently scheduled for 8 August 2014), such that they will collectively own approximately 58% of the combined entity (the Proposed Merged Entity). The Proposed Scheme is expected to be implemented in August 2014.

Upon completion of the Proposed Scheme, Horizon would become a wholly owned subsidiary of ROC and would subsequently be delisted from the Australian Securities Exchange (ASX).

The Board of the Proposed Merged Entity will comprise:

- three current non-executive directors from ROC, including Mr Mike Harding (the current Chairman of ROC) as the Chairman of the Proposed Merged Entity
- four current non-executive directors from Horizon, and Mr Brent Emmett (the current Chief Executive Officer (CEO) of Horizon) as the CEO and Managing Director of the Proposed Merged Entity.

The Board of Horizon has prepared a scheme booklet containing the detailed terms of the Proposed Scheme (the Scheme Booklet) and an overview of the Proposed Scheme is provided in Section 1 of our detailed report.

Purpose of the report

Section 411 of the Corporations Act 2001 (Corporations Act) regulates schemes of arrangement between companies and their shareholders. Section 411 (3) prescribes the information to be provided to shareholders in relation to schemes of arrangement.

Whilst an independent expert's report in respect of the Proposed Scheme is not required to be prepared to meet any statutory obligations, the directors of Horizon (the Directors) have requested that Deloitte Corporate Finance Pty Limited (Deloitte Corporate Finance) provide an independent expert's report advising whether, in our opinion, the Proposed Scheme is in the best interests of Horizon Shareholders.

This independent expert's report has been prepared in a manner consistent with Part 3 of Schedule 8 of the Corporations Regulations 2001 (Cwlth) to assist Horizon Shareholders in their consideration of the Proposed Scheme. We have prepared this report having regard to Part 3 and Australian Securities and Investments Commission (ASIC) Regulatory Guide 111 and ASIC Regulatory Guide 112.

This report is to be included in the Scheme Booklet to be sent to Horizon Shareholders and has been prepared for the exclusive purpose of assisting Horizon Shareholders in their consideration of the Proposed Scheme. Neither Deloitte Corporate Finance, Deloitte Touche Tohmatsu, nor any member or employee thereof, undertakes responsibility to any person, other than the Horizon Shareholders and Horizon, in respect of this report, including any errors or omissions however caused.

Basis of evaluation

Schemes of arrangement can include many different types of transactions. The basis of evaluation selected by the expert must be appropriate for the nature of each specific transaction.

ASIC Regulatory Guide 111 provides guidance in relation to the content of independent expert's reports prepared for a range of transactions.

In our opinion, from the perspective of Horizon Shareholders, the Proposed Scheme is not a control transaction as envisaged by ASIC Regulatory Guide 111. Horizon Shareholders will collectively own 58% of the shares of the Proposed Merged Entity, which is above the 50% threshold that is generally accepted to be a "controlling interest" and Horizon directors will control the Board of the Proposed Merged Entity. The strategic direction of the Proposed Merged Entity is likely to remain aligned with the present strategy of Horizon, albeit with a more diverse asset portfolio. Furthermore, significant shareholdings currently held in Horizon and ROC will be diluted to below 20% in the Proposed Merged Entity.

Paragraph 31 of the regulatory guide allows for the assessment of an all share takeover, where it is in effect a merger of entities, to be undertaken using an equivalent approach to valuing the securities of the bidder (in this case, ROC) and the target (Horizon).

Accordingly, we have assessed the offer as being:

- fair, when the value of the consideration is equal to or greater than the value of the securities subject to the proposed scheme. We have assessed fairness by comparing the value of one share in Horizon with the value of the interest to be received in the Proposed Merged Entity on an equivalent control basis
- reasonable, if it is fair, or, despite not being fair, after considering other significant factors, Horizon Shareholders should accept the offer under the Proposed Scheme, in the absence of any higher bids before the close of the offer.

Summary and conclusion

In our opinion the Proposed Scheme is fair and reasonable and therefore in the best interests of Horizon Shareholders.

In arriving at this opinion, we have had regard to the following factors.

The Proposed Scheme is fair

We have valued Horizon and ROC (and therefore the Proposed Merged Entity) on a fundamental basis largely with reference to the discounted cash flow methodology (which derives a value inclusive of a premium for control).

Accordingly, we have undertaken our merger analysis by:

- estimating the value of the shares in Horizon and the Proposed Merged Entity (being the combined operations of Horizon and ROC) on a control basis
- compared the relative values of a share in Horizon with an interest equivalent to 0.724 shares in the Proposed Merged Entity.

If the value of a share in Horizon is equal to or below the value of the interest to be received in the Proposed Merged Entity, the Proposed Scheme is fair.

Horizon has interests in oil and gas producing, development and exploration assets in China, Papua New Guinea (PNG) and New Zealand and is listed on the ASX with a current market capitalisation of approximately AUD 495 million[1]. ROC similarly holds interests in a portfolio of (predominantly) oil producing and exploration assets in China, Australia, the United Kingdom (UK), Myanmar and Malaysia, and is listed on the ASX with a current market capitalisation of approximately AUD 370 million. Horizon and ROC both own interests in the Beibu Gulf field (in China), which commenced production in 2013.

Set out below is a summary of our assessment of the relative values of a share in Horizon and the Proposed Merged Entity.[2]

Table 1: Valuation of a share in Horizon

	Section reference	Unit	Low	High
Enterprise value of operating assets	7.1	USD million	387	407
Enterprise value of development assets	7.1	USD million	180	260
Enterprise value of exploration assets	7.2	USD million	32	32
Corporate costs	7.3	USD million	(67)	(73)
Surplus assets / liabilities	7.3	USD million	154	174
Enterprise value of Horizon (on a control basis)		**USD million**	**687**	**801**
Net debt	7.3	USD million	(180)	(180)
Equity value (on a control basis)		**USD million**	**507**	**621**
Number of shares in Horizon	7.3	'million	1,317	1,317
Value of a share in Horizon (on a control basis)		**USD / share**	**0.38**	**0.47**

Source: Deloitte Corporate Finance analysis
Notes:
1. *USD – United States dollars*
2. *The net debt position and the number of shares in Horizon assume 15 million options held by Petsec Energy Limited were exercised prior to their expiry on 30 June 2014. We understand the options were not exercised as at the date of this report, however we have not updated our valuation to reflect this as it does not have a material effect thereon.*

Table 2: Valuation of a share in the Proposed Merged Entity

	Section reference	Unit	Low	High
Horizon:				
Enterprise value of operating assets	7.1	USD million	387	407
Enterprise value of development assets	7.1	USD million	180	260
Enterprise value of exploration assets	7.2	USD million	32	32
ROC:				
Enterprise value of operating assets	7.1	USD million	338	367
Enterprise value of exploration assets	7.2	USD million	31	31
Corporate costs:				
Horizon	7.3	USD million	(67)	(73)
ROC	7.4	USD million	(67)	(70)
Add: corporate synergies	7.4	USD million	35	45
Surplus assets				
Horizon	7.3	USD million	154	174
ROC	7.4	USD million	52	52

[1] Australian dollars
[2] All figures in this report are subject to rounding

	Section reference	Unit	Low	High
Enterprise value of the Proposed Merged Entity (on a control basis)		**USD million**	**1,076**	**1,226**
Net debt	7.4	USD million	(101)	(101)
Equity value (on a control basis)		**USD million**	**976**	**1,125**
Number of shares in the Proposed Merged Entity (on an undiluted basis)	7.4	million	1,641	1,641
Value of a share in the Proposed Merged Entity (on a control basis)		**USD / share**	**0.59**	**0.69**

Source: Deloitte Corporate Finance analysis

Our valuation of the shares in Horizon and the Proposed Merged Entity have been derived on both an undiluted and fully diluted share basis, which requires assumptions on the number of options that may be exercised into shares in Horizon and the Proposed Merged Entity in the future. Undertaking the valuation on a fully diluted basis and assuming the maximum number of options convert in each entity results in a minimal change in the value of the shares. Accordingly, we have undertaken our valuations on an undiluted basis.

Our valuation is sensitive to a number of assumptions made to value the assets of both Horizon and ROC. We have adopted the same approach in our valuation of the assets held by Horizon and those held by ROC, with similar key assumptions, including future oil prices and discount rates. Accordingly, changes to these key assumptions will have a similar effect on the value of assets held by Horizon and those held by ROC.

Key to our valuation of Horizon are the assumptions adopted in respect of the PNG assets and the strategy for developing the gas resources. The technical expert engaged to assist Deloitte Corporate Finance in this assignment, RISC Operations Pty Limited (RISC), provided a technical assessment of certain key assumptions underpinning the financial model for the operating assets and development projects of Horizon and ROC. RISC assisted Deloitte Corporate Finance in developing various valuation scenarios for the PNG assets, which we have considered in selecting our preferred scenario, together with risk factors to apply to the cash flows generated under our preferred scenario.

The production assumptions adopted under our preferred scenario for each asset are summarised as follows:

- for the Stanley field: 13 million barrels of oil equivalent (mmboe) of condensate volumes and 315 petajoules (PJ) of gas volumes extracted under a liquids stripping and gas export case (on a 100% basis)
- for the Elevala-Ketu field: 50 mmboe of condensate volumes and 1,024 PJ of gas volumes extracted under a liquids stripping and gas export case (on a 100% basis).

We have assumed that a 1.5 million tonne per annum (mtpa) mid-scale liquefied natural gas (LNG) facility will be developed in Daru, which is one of the options currently under consideration by Horizon. LNG facilities, however, have long lead times and require significant capital investment. RISC has estimated the capital cost of a mid-scale facility to be in the region of USD 2 billion with annual operating costs of USD 130 million.

The economics of a mid-scale LNG facility also depend on the volumes of gas to be processed, with greater volumes creating economies of scale and a lower cost per unit of production from the two fields. Taking into account the above and our preferred LNG prices (USD 14.00 per gigajoule (GJ) to USD 15.00 per GJ), we have selected ex-field netback prices in the range of USD 7.50 per GJ to USD 8.50 per GJ. We have also had regard to prices currently being considered by Horizon and potential domestic gas customers.

Whilst we have assumed a mid-scale LNG development, many milestones need to be met, at significant cost and risk, for the gas export case for the two fields to become a reality. RISC has estimated that, where completion of the LNG facility is delayed by one year, additional capital expenditure of USD 30 million (in 2014 real terms) would result, along with delays in production in the Elevala-Ketu field.

Given the uncertainty associated with the manner in which the significant potential of the gas resources will be developed in the Stanley and Elevala-Ketu fields, we have also assumed that completion of the LNG facility will be delayed by one year. In addition, we have also applied a probability factor of 50% to 60% to the overall net present value ascribed to the interests in these assets.

Where the gas is not sold in the manner and timeframes assumed, or the metrics of monetisation are less favourable than that assumed, the value of the interests held by Horizon in these two fields may be lower, which would make the Proposed Scheme more attractive to Horizon Shareholders.

We have also used other information to cross-check our valuation:

- the values ascribed to each of the other oil producing assets in which Horizon and ROC hold interests (by way of an industry rule of thumb)
- the value ascribed to the PNG assets based on the value implied by the Osaka Gas Transaction (refer to Section 3.2 for further details on this transaction) and recent transactions in a nearby field in PNG
- the overall value ascribed to Horizon and the Proposed Merged Entity, on a sum-of-the-parts basis, by comparison to the share prices of Horizon and ROC.

In our opinion these cross-checks support our valuation of Horizon and the Proposed Merged Entity on a control basis.

Set out below is our assessment of fairness.

Table 3: Assessment of the Proposed Scheme

	Unit	Low	High
Assessment of the Proposed Scheme in USD			
Value of a share in Horizon (on a control basis)	**USD / share**	**0.38**	**0.47**
Value of a share in the Proposed Merged Entity (on a control basis)	USD / share	0.59	0.69
Merger ratio (shares in the Proposed Merged Entity per share held in Horizon)	#	0.724	0.724
Value per Horizon share to be received in the Proposed Merged Entity	**USD / share**	**0.43**	**0.50**
Assessment of the Proposed Scheme in AUD[1]			
Value of a share in Horizon (on a control basis)	**AUD / share**	**0.41**	**0.50**
Value of a share in the Proposed Merged Entity (on a control basis)	AUD / share	0.63	0.73
Merger ratio (shares in the Proposed Merged Entity per share held in Horizon)	#	0.724	0.724
Value per Horizon share to be received in the Proposed Merged Entity	**AUD / share**	**0.46**	**0.53**

Source: Deloitte Corporate Finance analysis
Note:
1. *USD figures converted in AUD using an exchange rate of 0.94 USD: 1.00 AUD.*

The value of the interest in the Proposed Merged Entity is above the value of share in Horizon. Accordingly it is our opinion that the Proposed Scheme is fair.

If we had undertaken the assessment on a consistent minority interest basis, the Proposed Scheme would also be fair.

The Proposed Scheme is reasonable

In accordance with ASIC Regulatory Guide 111 an offer is reasonable if it is fair. On this basis, in our opinion the Proposed Scheme is reasonable. We have also considered the following factors in assessing the reasonableness of the Proposed Scheme.

The Proposed Scheme will assist Horizon to fund the Company's substantial development programmes

Horizon is projected to incur USD 30 million in capital expenditure over the next three years in relation to the interests it holds in the Maari/Manaia and Beibu Gulf operating assets. In addition, developing the Stanley field and (later) the Elevala-Ketu fields is projected to cost Horizon approximately USD 330 million (in 2014 real terms) between 2014 and 2019 (excluding any capital cost of the LNG processing facility).

Horizon had approximately USD 23 million in cash (including restricted cash of approximately USD 14 million) as at 31 March 2014. Notwithstanding the proceeds to be received from the Osaka Gas Transaction by mid-2014 (USD 78 million in total)[3], and forecast free cash flows generated from its interests in its operating assets, funding the PNG development programme will likely require Horizon to access additional capital, either by way of an expansion in its debt facilities or an equity raising. In our opinion, given the risk profile of the PNG development assets and the redemption rights associated with the Convertible Bonds issued by Horizon, an equity raising may be required.

The merger with ROC provides Horizon with a complementary portfolio of assets that are projected to generate free cash flows of between USD 60 million and USD 80 million per annum over the next three years. Together with the unencumbered cash ROC had as at 31 March 2014 of USD 88 million, the merger with ROC will assist in funding Horizon's medium term capital expenditure requirements, whilst providing Horizon Shareholders with the opportunity to acquire interests in assets that are already producing and generating cash inflows. In the case of the Beibu Gulf assets, the merger of the two companies will consolidate their interests in the Beibu Gulf field.

The Proposed Merged Entity will have greater geographic diversification, increased scale and a potentially elongated production profile than Horizon on a standalone basis

The assets in which Horizon owns its interests are located in New Zealand (producing and exploration assets), China (producing and exploration assets) and PNG (development, pre-development and exploration assets). The merger of the two companies will result in geographic diversification into Malaysia (producing and exploration assets) and, to a lesser extent, Australia, the UK and Myanmar.

Enhanced liquidity and broker coverage

The increased market capitalisation of the Proposed Merged Entity and enlarged shareholder base may attract greater analyst coverage and may lead to the inclusion of the Proposed Merged Entity in other share market indices.

Following the Proposed Scheme, the market capitalisation of the Proposed Merged Entity will be greater than that of Horizon on a standalone basis and Horizon's single significant shareholder (Austral-Asia Energy Pty Limited) will have its approximate interest of 25% initially diluted to approximately 14%. The increase in size of the Proposed Merged Entity compared to Horizon on a standalone basis may lead to an enhanced share market profile for the Proposed Merged Entity and may provide increased liquidity and greater depth of trading than that currently available to Horizon Shareholders.

Horizon is currently included in the S&P/ASX 200 Index and, over time, the Proposed Merged Entity may be included in the S&P/ASX 100 Index. Furthermore, the Proposed Merged Entity may be followed by additional analysts following the Proposed Scheme, compared to Horizon and ROC, on a standalone basis. Greater analyst coverage may also result in enhanced trading liquidity.

The Proposed Merged Entity may have improved access to both debt and equity capital markets, possibly on more attractive terms, compared with those currently available to Horizon on a standalone basis.

Retention of control

If the Proposed Scheme is implemented, Horizon directors will comprise the majority of the Board of the Proposed Merged Entity, thus preserving the strategic direction of the Board of Horizon.[4] In any event, the strategic direction of the Proposed Merged Entity would appear to be closely aligned with that of Horizon prior to the Proposed Scheme, which is focused on developing the PNG oil and gas fields of Stanley and Elevala-Ketu.

Horizon Shareholders will continue to own shares in an oil and gas company with interests in oil producing and oil and gas development assets, albeit shares in a larger entity, with more attractive investment characteristics than that exhibited by Horizon on a standalone basis.

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[3] Approximately USD 77 million was paid to Horizon on 12 June 2014, with a further USD 1 million (approximately) to be received in the short term

[4] The Board will comprise four current non-executive directors from Horizon (plus the current CEO of Horizon as the CEO and Managing Director of the Proposed Merged Entity) and three non-executive directors from ROC. The terms of the Merger Implementation Deed acknowledge that one Horizon director will retire from the Board of the Proposed Merged Entity at or before the Annual General Meeting in 2015.

The Horizon Shareholders will continue to have an opportunity to realise a premium for control for their shareholding even after the Proposed Scheme is implemented. The improved profile of the Proposed Merged Entity relative to Horizon on a standalone basis may make it more attractive to other potential buyers.

Share prices may trade below current levels in the absence of the Proposed Scheme proceeding

Since the announcement of the Proposed Scheme, Horizon's share price has traded higher than prices immediately prior to announcement of the Proposed Scheme. Horizon's share price may fall if the Proposed Scheme does not proceed, in the absence of an alternative proposal eventuating.

Control premium implicit in the Proposed Scheme

The implied premium for control based on share price analysis is towards the low end of the typical range we have observed in transactions in Australia over the course of the last 10 years (i.e. 20% to 40%).

As we consider this transaction to be a merger with no change in control, we would not expect Horizon Shareholders to receive a significant control premium in the Proposed Scheme.

Table 4

	Unit	
5-day VWAP[1] of Horizon shares (pre-announcement)	**AUD / share**	**0.35**
10-day VWAP of Horizon shares (pre-announcement)	**AUD / share**	**0.33**
30-day VWAP of Horizon shares (pre-announcement)	**AUD / share**	**0.32**
5-day VWAP of ROC shares (up to close of trading on 24 June 2014)	AUD / share	0.56
Merger ratio (shares in the Proposed Merged Entity per share held in Horizon)	#	0.724
Implied value per Horizon share	**AUD / share**	**0.41**
Implied control premium		
5-day VWAP of Horizon shares		*17%*
10-day VWAP of Horizon shares		*24%*
30-day VWAP of Horizon shares		*28%*

Source: Capital IQ; Deloitte Corporate Finance analysis
Note:
1. VWAP – volume weighted average price.

The share price of ROC has increased in recent weeks. Since announcement of the Proposed Scheme, a number of announcements unrelated to the Proposed Scheme have been released by both ROC and Horizon which may have influenced trading in ROC's shares in recent weeks, including ROC confirming that it had received an unsolicited takeover offer from a third party (on 25 June 2014). An independent expert's report prepared for ROC on the Proposed Scheme was also released on 16 June 2014.

The disadvantages are not significant when weighed against the advantages

The Proposed Scheme does not appear to have any significant disadvantages for Horizon Shareholders. However, Horizon Shareholders will dilute their participation in the future growth of Horizon's gas prospects in PNG. On the other hand, the Proposed Scheme adds diversification benefits and a portfolio of cash generating assets, without which it may be difficult to realise the underlying value of the PNG assets.

Other matters

As at the date of this report, no superior offers have emerged (of which we are aware).

An individual Horizon Shareholder's decision in relation to the Proposed Scheme may be influenced by his or her particular circumstances. If in doubt the Horizon Shareholder should consult an independent adviser, who should have regard to their individual circumstances.

This opinion should be read in conjunction with our detailed report which sets out our scope and findings.

Yours faithfully

DELOITTE CORPORATE FINANCE PTY LIMITED

Stephen Reid	**Robin Polson**
Director	Director

Deloitte.

Glossary

Reference	Definition
2C	Proved plus Probable Contingent resources
2P	Proved plus Probable reserves
AFSL	Australian Financial Services Licence
APPI	Asian Petroleum Price Index
ASIC	Australian Securities and Investments Commission
ASX	Australian Securities Exchange
AUASB	Auditing and Assurance Standards Board
AUD	Australian dollars
β	Beta
Bcf	Billion cubic feet
bcm	Billion cubic metres
boe	Barrel of oil equivalent
bopd	Barrels of oil per day
CAPM	Capital Asset Pricing model
CEO	Chief Executive Officer
CIF	Cartage and freight
CNOOC	Chinese National Offshore Oil Corporation
Company, the	Horizon Oil Limited
Convertible Bonds	The 400 convertible bonds issued by Horizon in 2011 for USD 80 million
Corporations Act	Corporations Act 2001
CRP	Country risk premium
CY	Calendar year
Deloitte Corporate Finance	Deloitte Corporate Finance Pty Limited
Directors, the	The directors of Horizon
EBIT	Earnings before interest and tax
EBITDA	Earnings before interest, tax, depreciation and amortisation
EIA	Energy Information Administration
EIU	Economist Intelligence Unit
EMRP	Equity Market Risk Premium
FID	Final Investment Decision
FPSO	Floating Production Storage and Offload vessel
FSG	Financial Services Guide
FY	Financial year
GJ	Gigajoule
Horizon	Horizon Oil Limited
Horizon Model, the	The model that estimates the future cash flows from each of the operating and development asset of Horizon
Horizon Shareholders	Shareholders in Horizon
IBISWorld	IBIS World Pty Limited
IEA	International Energy Agency
Incentive Payment	The payment offered by Horizon to bondholders under the Private Early Redemption Offer (estimated to be USD 5 million (assuming all 400 Convertible Bonds convert))
IRAC	Imported Refiner Acquisition Cost
JCC	Japanese Crude Cocktail
K_d	Cost of debt capital
K_e	Cost of equity capital
km	Kilometres
km^2	Square kilometres
LNG	Liquefied natural gas
LTI Rights	Long Term Incentive Rights
LTIP	Long term Incentive Plan
mmbbl	Million barrels
mmboe	Million barrels of oil equivalent

Reference	Definition
mmscfd	Million standard cubic feet per day
Models, the	Together, the Horizon and ROC Models
mtpa	Million tonnes per annum
n/a	Not applicable
NYMEX	New York Mercantile Exchange
OECD	Organisation for Economic Co-operation and Development
OMV	OMV New Zealand
OPEC	Organisation of the Petroleum Exporting Countries
Osaka Gas	Osaka Gas Niugini Pty Limited
Osaka Gas Transaction	Transaction with Osaka Gas by which Horizon sold a 40% interest in its interests owned in the Stanley and Elevala-Ketu fields in 2013
PDL	Production Development Licence
Petsec	Petsec Energy Limited
PJ	Petajoules
PNG	Papua New Guinea
Private Early Redemption Offer	The offer by Horizon to bondholder of a premium over the current redemption price of the bonds where bondholders commit to redeem all of their Convertible Bonds following implementation of the Proposed Scheme
PRL	Petroleum Retention Licence
Proposed Merged Entity	Merged entity of Horizon and ROC
Proposed Scheme, the	The proposal under which Horizon and ROC would merge by way of ROC acquiring all of the issued shares in Horizon via a scheme of arrangement
PRRT	Petroleum resource rent tax
PSC	Production Sharing Contract
R_f	Risk free rate of return
RISC	RISC Operations Pty Limited
R_m	Expected return on the market portfolio
ROC	ROC Oil Company Limited
ROC Model, the	The model that estimates the future cash flows from each of the operating and development asset of ROC
RSC	Risk Services Contract
SARs	Share Appreciation Rights
Scheme Booklet	Scheme booklet containing the detailed terms of the Proposed Scheme
STI Rights	Short Term Incentive Rights
UK	United Kingdom
USD	US dollars
VWAP	Volume weighted average price
WACC	Weighted average cost of capital
WTI	West Texas Intermediate

Contents

1 Overview of the Proposed Scheme

1.1 Summary of the Proposed Scheme

1.1.1 Overview

Horizon and ROC will merge by way of ROC acquiring all of the issued shares in Horizon. The merger is being effected by way of a scheme of arrangement:

- as it will minimise the need for any third party approvals
- because it provides greater certainty that in the event that the Proposed Scheme is approved by Horizon Shareholders and the Court, 100% of Horizon will be acquired by ROC
- it should also ensure that scrip-for-scrip capital gains tax roll-over relief is available for Horizon Shareholders.

If the Proposed Scheme is approved, Horizon Shareholders (other than ineligible foreign shareholders) will receive 0.724 ROC shares for every share held in Horizon at the Record Date, such that they will collectively own approximately 58% of the Proposed Merged Entity. The Proposed Scheme is expected to be implemented in August 2014.

Those foreign Horizon Shareholders deemed to be ineligible will not be issued shares in ROC under the Proposed Scheme and will instead have their share entitlement in ROC issued to a nominee to facilitate the sale of the shares on the ASX. The net proceeds will be distributed proportionately amongst ineligible foreign Horizon Shareholders.

Upon completion of the Proposed Scheme, Horizon would become a wholly owned subsidiary of ROC and would subsequently be delisted from the ASX.

Partly-paid shares, unlisted options and Share Appreciation Rights (SARs) issued by Horizon, and Convertible Bonds issued by Horizon, will be subject to different treatment in the Proposed Scheme (discussed below).

1.1.2 Treatment of partly-paid shares, options and SARs in Horizon

In addition to the 1,302 million fully paid ordinary shares, Horizon has a number of partly-paid shares, unlisted options and SARs on issue to various eligible employees and third parties.

Under the Merger Implementation Deed, it is intended that the options and SARs in Horizon are transferred to ROC (at an equivalent value) or cancelled prior to implementation of the Proposed Scheme, with holders of cancelled securities receiving consideration that is reasonably acceptable to Horizon, the holders and ROC. In particular:

- **partly paid shares:** holders of partly-paid shares in Horizon will receive 0.724 fully paid shares in ROC for each partly-paid share held in Horizon and their debt obligation to Horizon will be transferred to ROC such that they will remain liable to ROC for the residual payments owing on those partly-paid shares
- **vested options:** holders of vested options will be deemed to have exercised their options and a corresponding number of shares in Horizon will be issued to the option holder with effect from the day following the Proposed Scheme meeting. Holders of vested options will receive the consideration under the Proposed Scheme, but will remain liable to ROC for the amount equal to the exercise price of such options, with the amount payable on or before the date on which the exercise price would otherwise have been payable to Horizon. In effect, the vested options will become partly paid shares in ROC
- **unvested (in-the-money) options and SARs:** unvested options which are in-the-money and SARs will be cancelled on the day following the Proposed Scheme meeting and, in exchange, their holders will be entitled to receive a number of new options in ROC equivalent in value to those options and SARs which were cancelled, with a revised strike price based on the merger ratio
- **unvested (out-the-money) options:** Horizon may elect (if requested by the option holder) to cancel unvested options which are out-of-the- money in exchange for a cash payment equivalent to the value of the option, calculated with reference to the Black-Scholes valuation methodology, otherwise the options will be treated in the same manner as unvested (in-the-money) options.

The above can be summarised as follows:

Table 5

	Number of shares	Shares to be Issued in ROC	Outstanding loans to be transferred (AUD)
Partly-paid shares	1,500,000	1,086,000	427,500

Source: Horizon

Table 6[1]

Issue date	Number of options outstanding	Number of options vested	Remaining unvested options: in-the-money	Remaining unvested options: out-of-the-money	Shares to be issued in ROC	Options to be issued in ROC	Valuation of out-of-the-money options (AUD)
Employee Options							
25-Sep-09	5,175,000	5,175,000	-	-	3,746,700	-	
25-Sep-09	350,000	350,000	-	-	253,400	-	
9-Oct-09	2,700,000	2,700,000	-	-	1,954,800	-	
16-Sep-10	350,000	350,000	-	-	253,400	-	
28-May-12	1,666,667	1,000,001	666,666	-	724,001	594,748	
17-Sep-12	500,000	166,667	333,333	-	120,667	296,824	
20-Feb-13	350,000	-	-	350,000	-	-	41,043
20-Feb-13	350,000	-	-	350,000	-	-	43,791
Total	**11,441,667**	**9,741,668**	**999,999**	**700,000**	**7,052,969**	**891,572**	**84,834**
General Options							
11-Dec-09	500,000	500,000	-	-	362,000	-	-
6-Jun-11	15,000,000	15,000,000	-	-	n/a	-	-
10-Jan-12	1,000,000	666,667	333,333	-	482,667	310,272	-
28-May-12	2,000,000	1,333,334	666,666	-	965,334	636,882	-
Total	**18,500,000**	**17,500,001**	**999,999**	**-**	**1,810,001**	**947,154**	**-**
SARs							
1-Oct-10	6,693,828	-	6,693,828	-	-	5,790,654	-
5-Aug-11	6,478,276	-	6,478,276	-	-	5,342,158	-
13-Aug-12	9,561,936	-	9,561,936	-	-	7,529,173	-
19-Aug-13	8,547,599	-	8,547,599	-	-	6,736,777	-
Total	**31,281,639**	**-**	**31,281,639**	**-**	**-**	**25,398,762**	**-**
Total	**61,223,306**	**27,241,669**	**33,281,638**	**700,000**	**8,862,969**	**27,237,488**	**84,834**

Source: Horizon
Notes:
1. *Refer to Section 2.3 for further details on options and SARs issued in Horizon*
2. *n/a – not applicable; this parcel of options will expire prior to implementation of the Proposed Scheme. The options are currently marginally in the money.*

Following implementation of the Proposed Scheme, the Proposed Merged Entity may receive proceeds from option holders who exercise their options. However, the options will convert into partly-paid shares initially under the terms of Horizon option schemes.

We have undertaken an analysis to assess the dilution effect of the unvested options exercising to their fullest extent and the maximum number of shares arising from conversion of the SARs into shares in Horizon and the Proposed Merged Entity. We have determined that the impact is immaterial on the overall value estimated for a share in both Horizon and the Proposed Merged Entity.

Full details on the proposed treatment of the partly-paid shares, options and SARs issued by Horizon are provided in the Scheme Booklet.

1.1.3 Treatment of Convertible Bonds

Horizon issued 400 5.5% Convertible Bonds for USD 80 million on 17 June 2011, which have a maturity date of 17 June 2016. The Convertible Bonds can be satisfied and discharged by conversion into Horizon shares prior to the maturity date, at the option of the bondholder, or redemption on the maturity date.

If implemented, the Proposed Scheme would trigger an adjustment event (which results in a reduced conversion price becoming available to bondholders) and a redemption right (which results in an early repayment opportunity becoming available to bondholders). Bondholders can elect to action either one of those triggers.

The merits of conversion or redemption of the Convertible Bonds will depend on, among other things, the price of Horizon and ROC shares and the USD / AUD exchange rate prevailing at the date of conversion.

If bondholders elect to convert, Horizon may elect to settle the conversion by making a cash payment to bondholders in lieu of issuing new shares in Horizon.

Horizon intends to offer a premium to bondholders who commit to redeem all of their Convertible Bonds following implementation of the Proposed Scheme under the terms of the Private Early Redemption Offer.

Private Early Redemption Offer

The key terms of the Private Early Redemption Offer are:

- the offer is conditional upon the Proposed Scheme becoming effective
- bondholders who accept the offer and redeem their Convertible Bonds will receive a premium of 625 basis points above the "Early Redemption Amount" which they are entitled to receive under the terms of the Convertible Bonds, to be funded from the available cash of the Proposed Merged Entity (the Incentive Payment)
- the offer must be accepted for all (not some) of the Convertible Bonds held by a bondholder
- bondholders who accept the Private Early Redemption Offer agree to vote in favour of a resolution, which may be proposed at a meeting of bondholders to consider an amendment to the conditions of the Convertible Bonds in order to include a right for Horizon to redeem any outstanding Convertible Bonds.

The Early Redemption Amount is estimated at USD 84 million (for all 400 Convertible Bonds) and the Incentive Payment is currently estimated at USD 5 million (assuming all 400 Convertible Bonds are redeemed).

Potential for compulsory acquisition under the Corporations Act

Following implementation of the Proposed Scheme, ROC may seek to compulsorily acquire any outstanding Convertible Bonds in several ways.

- **existing rights under the terms of the Convertible Bonds:** under the terms of the Convertible Bonds, there is a right to redeem all outstanding Convertible Bonds if conversion or redemption is effected in respect of 90% or more (by principal amount) of the Convertible Bonds
- **meeting to amend the terms of the Convertible Bonds:** a meeting of bondholders may be called to amend the terms of the Convertible Bonds by "Extraordinary Resolution" (75% or more of those attending and voting at the relevant meeting) to include a right for Horizon to redeem any outstanding Convertible Bonds.

  If the "Extraordinary Resolution" is approved, the option right may be exercised to redeem any outstanding Convertible Bonds
- **general compulsory acquisition under the Corporations Act:** if the Proposed Scheme is implemented and ROC obtains a shareholding which represents, in aggregate, at least:
  - 90% of the voting power in Horizon; and
  - (either alone or with a related body corporate) full beneficial interests in at least 90% by value of all the securities of Horizon that are either shares or convertible into shares.

  ROC may seek to compulsorily acquire the outstanding Convertible Bonds (i.e. those remaining after any are redeemed under the Private Early Redemption Offer) in accordance with sections 664A to 664G of the Corporations Act.

1.2 Key conditions of the Proposed Scheme

The Proposed Scheme is subject to customary regulatory approvals and various conditions, the most significant being:

- no "ROC Oil Prescribed Event" or "Horizon Prescribed Event" having occurred as stipulated in the Merger Implementation Deed
- the independent expert engaged to assist Horizon Shareholders concluding that the Proposed Scheme is in the best interests of the Horizon Shareholders
- "PRL Completion" (as defined in the Osaka Gas Asset Sale Agreement) having occurred under and in accordance with the Osaka Gas Asset Sale Agreement
- Horizon Shareholders approving the Proposed Scheme at the Scheme Meeting (75% of votes cast; 50% of shareholders voting)
- Court approval of the Scheme in accordance with section 411(4)(b) of the Corporations Act.

On 15 May 2014, ROC advised the ASX that it had received a notice under section 249D of the Corporations Act from a substantial shareholder requesting a general meeting of ROC shareholders to consider a special resolution to amend the company's Constitution. The amendment of ROC's Constitution would qualify as a "ROC Oil Prescribed Event" under the Merger Implementation Deed, which, unless waived by Horizon, would entitle Horizon to terminate the Merger Implementation Deed and the Proposed Scheme would not complete.

As at the date of this report, Horizon has not formed an intention or view on the course of action it may take if the proposed resolution is passed by ROC shareholders and reserves its rights in this regard.

Horizon does not presently intend to consent to the altering of ROC's Constitution (although it reserves its right to do so) and expects that ROC will honour all of its obligations under the Merger Implementation Deed. If ROC's Constitution is amended, Horizon will undertake all steps available to it to preserve its rights pursuant to the Merger Implementation Deed (which may include claiming damages for any breach of the Merger Implementation Deed to the fullest extent possible).

2 Profile of Horizon

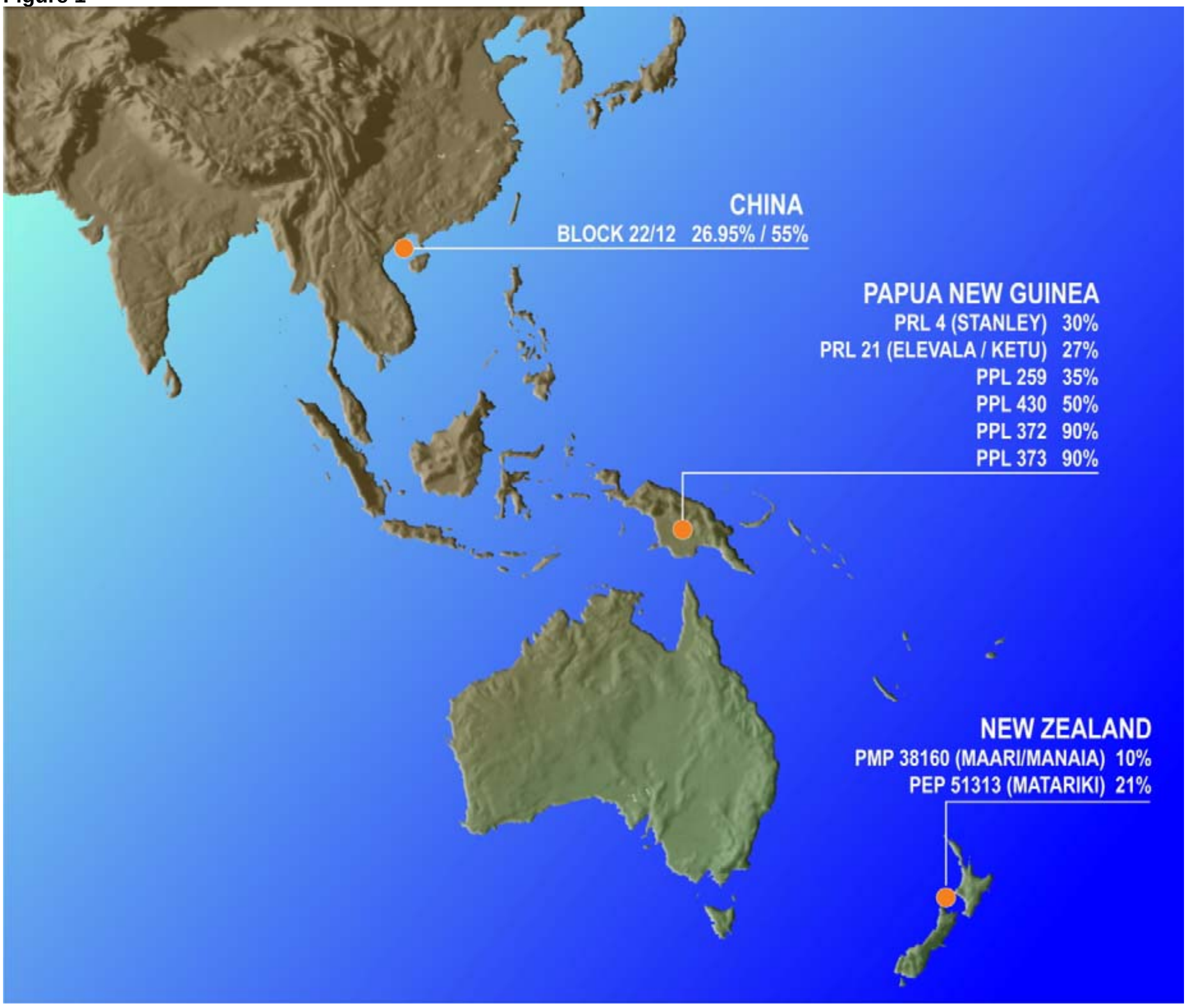
2.1 Company overview

Horizon is an upstream oil and gas company listed on the ASX. Previously known as Bligh Oil & Minerals NL, the company eventually changed its name to Horizon Oil Limited in January 2004. Horizon is based in Woolloomooloo, New South Wales and has interests in oil and gas producing, development and exploration assets in China, PNG and New Zealand.

Horizon's producing assets in China operate under a Production Sharing Contract (PSC) with the Chinese Government. A state-owned entity, CNOOC, currently holds a 51% interest in the Beibu Gulf project, and also operates the project. Horizon's production and development assets in New Zealand and PNG are held under concession agreements with the New Zealand and PNG governments. Under the PNG concession agreements, the PNG Government reserves the right to participate up to a 22.5% equity interest in any project which progresses to commercial development[5].

The following figure outlines the location of Horizon's principal assets.

Figure 1[1]



Source: Horizon website
Note:
1. *The Petroleum Development Licence for the Stanley field (formerly PRL 4) was issued on 30 May 2014. PRL 4 is now known as PDL 10.*

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[5] The PNG Government may appoint a state nominee to acquire up to a 22.5% interest in the commercial development of a project. The price payable for this interest is equal to the sunk costs incurred by the joint venture participants.

2.2 Principal assets

The portfolio of assets held by Horizon is summarised in the following table.

Table 7

Asset	Location	% ownership	Other owners	Operator	Type of project
Operating assets					
PMP 38160 (Maari/Manaia)	New Zealand	10.00%	OMV New Zealand (69.00%) Todd Corporation (16.00%) Cue Energy (5.00%)	OMV New Zealand	Oil
Beibu Gulf – Block 22/12 (WZ 6-12, WZ 12-8 West)	China	26.95%	CNOOC (51.00%) ROC (19.60%) Majuko Corporation (2.45%)	CNOOC	Oil
Development / pre-development assets					
PDL 10 (Stanley)	PNG	30.00%[2]	Osaka Gas (20.00%) Talisman Energy (40.00%) Mitsubishi Corporation (10.00%)	Talisman Energy	Condensate and gas
PRL 21 (Elevala, Ketu)	PNG	27.00%[2]	Osaka Gas (18.00%) Talisman Energy (32.50%) Kina Petroleum (15.00%) Mitsubishi Corporation (7.50%)	Horizon	Condensate and gas
Exploration assets					
PEP 51313 (Matariki, Whio)	New Zealand	21.00%/10.00%[3]	OMV New Zealand (30.00%) Todd Corporation (35.00%) Cue Energy (14.00%)	OMV New Zealand	Oil
Beibu Gulf – Block 22/12 (WZ 12-8 East)	China	55.00%[1]	ROC (40.00%) Majuko Corporation (5.00%)	CNOOC	Oil
PPL 259	PNG	35.00%[2]	Osaka Gas (10.00%) Eaglewood (45.00%) Mega Fortune International (10.00%)	Eaglewood[5]	Condensate and gas
PPL 372	PNG	90.00%/54.00%[2, 4]	Osaka Gas (36.00%)	Horizon	Condensate and gas
PPL 373	PNG	90.00%/54.00%[2, 4]	Osaka Gas (36.00%)	Horizon	Condensate and gas
PPL 430	PNG	50.00%/30.00%[2, 4]	Osaka Gas (20.00%) Eaglewood (50.00%)	Horizon	Condensate and gas

Source: Horizon Annual Report 2013; ASX announcements
Notes:
2. *Subject to reduction to allow for CNOOC participation at 51%*
3. *Subject to reduction to allow for PNG State Nominee participation at 22.5%*
4. *In the event of a commercial discovery at Whio, Horizon's interest in the Whio area will reduce to 10%*
5. *Subject to a reduction to allow for Osaka Gas to participate up to 36%, at Osaka Gas' option*
6. *Under the terms of the farm-in agreement between Horizon and Eaglewood in October 2013, Horizon will operate the Nama exploration well to be drilled in the licence in 2014.*

A summary of the reserves, resources and prospective resources for Horizon, on an economic interest basis and post the Osaka Gas Transaction, as at 1 January 2014 is set out in the table below. The reserves and resources presented below represent Horizon's view; refer to the technical expert's report (in Appendix G) for RISC's view on the reserves and resources attributable to the assets.

Table 8

Asset[1]	Oil (mmbbl)	Gas (Bcf)	Condensate (mmbbl)	Total (mmboe)
Proved Plus Probable Reserves (2P)				
Block 22/12 (WZ 6-12, WZ 12-8 West)	6.5	-	-	6.5
PMP 38160 (Maari/Manaia)	6.0	-	-	6.0
PDL 10 (Stanley)	-	-	3.4	3.4
Total	**12.5**	**-**	**3.4**	**15.9**
Proved Plus Probable Contingent (2C)				
Block 22/12 (WZ 12-8 East)	1.5	-	-	1.5
PDL 10 (Stanley)	-	120.0	0.4	20.4
PRL 21 (Elevala)	-	186.0	9.6	40.5
PRL 21 (Ketu)	-	79.0	3.8	16.9
Total	**1.5**	**385.0**	**13.8**	**79.3**
Prospective Resources				
Block 22/12	3.0	-	-	3.0
PMP 38160 (Maari/Manaia)	2.0	-	-	2.0
PEP 51313	12.0	-	-	12.0
PRL 21	-	17.0	1.0	4.0
PRL 259	-	295.0	12.0	61.0
Total	**17.0**	**312.0**	**13.0**	**82.0**

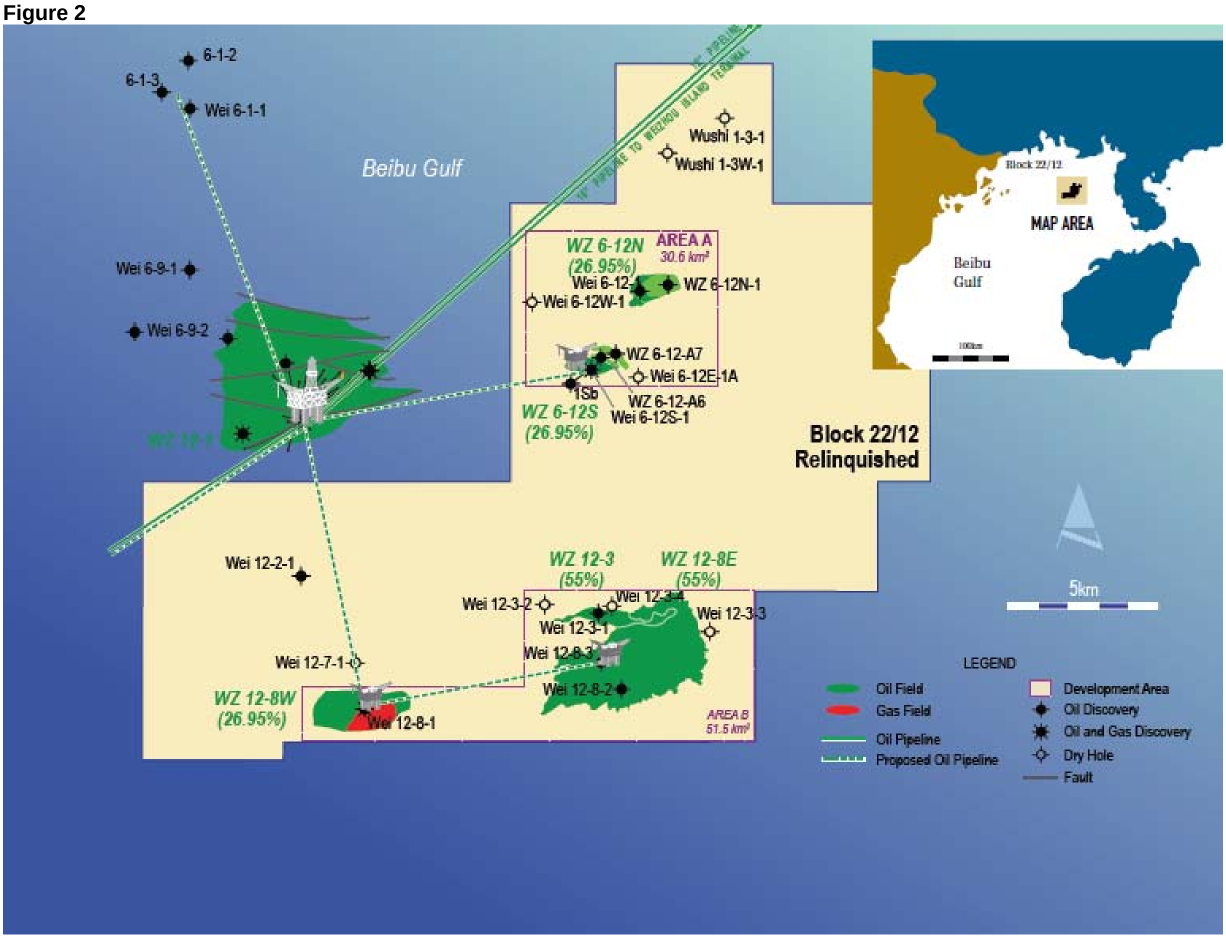
Source: Horizon management
Note:
1. *A detailed description of the underlying reserves and resources methodology supporting these estimates is outlined in the Scheme Booklet. Please refer to the relevant section of the Scheme Booklet for this information.*

2.2.1 Beibu Gulf, China

The Beibu Gulf assets lie in Block 22/12, a 364km^2 licence area located in the South China Sea, approximately 60km from the southern coast of China. The project is currently producing oil at a rate of 13,330 bopd[6] (100% basis for the quarter ended 31 March 2014) from operations at the WZ 6-12 and WZ 12-8 West fields, with peak production from the project anticipated at rates of 16,000 to 18,000 bopd. Production is transported to the Weizhou Island storage and export terminal via pipeline. Proposed development activities in the WZ12-8 East field continue to be explored as operations at the WZ 6-12 and WZ 8-12 West fields ramp up, following commencement of production in early 2013.

Horizon currently holds a 26.95% working interest in the producing assets, with the other joint venture partners, CNOOC, ROC and Majuko Corporation holding a 51%, 19.60% and 2.45% interest, respectively. The locations of the assets within Block 22/12 are set out in the figure below.

Figure 2



Source: Horizon Annual Report 2013

Horizon's initial 100% interest in the Block 22/12 assets was acquired on signing the PSC with CNOOC in 1999. Subsequent farm-outs to ROC, Majuko Corp and Petsec Energy Limited (Petsec) reduced Horizon's interest to 30%. In June 2011, Horizon acquired an additional 25% interest in the assets from Petsec, bringing its interest in the assets to 55.00%. Under the terms of the PSC between CNOOC and Horizon, CNOOC was provided with the right to participate at up to a 51% equity interest in any commercial developments within Block 22/12[7].

Four primary fields have been identified in the area, being the WZ 6-12 fields (North and South) and WZ 12-8 fields (East and West). The Block 22/12 assets have been developed in two phases. Phase I of the Beibu Gulf development plan involved the development of the WZ 6-12 South, WZ 6-12 North and the WZ 12-8 West

[6] Horizon company announcement, 30 April 2014
[7] Horizon website

fields, with WZ 12-8 East expected to follow in Stage II of the development. The production period outlined in the Block 22/12 petroleum contract is 15 years, with the possibility of extension following approval of the Chinese Government.

Following the successful development of the Stage I assets, CNOOC exercised its right to a 51% equity interest in the assets, bringing Horizon's working interest therein to 26.95%, and the interests of the other joint venture partners, ROC and Majuko Corporation, to 19.60% and 2.45%, respectively. Horizon maintained a 55.00% interest in the primary Stage II field, WZ 12-8 East, following the transaction[8].

First production was achieved at Block 22/12 in March 2013 from the WZ 6-12 fields at a rate of 10,000 bopd (100% basis) with production from the third Stage I field, WZ 12-8 West, commencing in August 2013 to bring cumulative production of the Stage I assets to 4.22 mmbbl as at 31 March 2014[9]. Production from the WZ 6-12 and WZ 8-12 West wellhead platforms is tied-in to an adjacent CNOOC-operated processing facility, before being transported to CNOOC's existing Weizhou Island storage and export terminal via a 34km pipeline, also owned and operated by CNOOC.

Production rates from the Stage I fields have been consistent with forecasts outlined in the Independent Reserves Report produced by RISC in 2012 (namely peak plateau production for the overall project of between 16,000 and 18,000 bopd[10]). Production from the Stage I fields is expected to continue through to 2025[11]. There have been two brief periods of downtime since production commenced (totalling 12 days), as a result of poor weather in the area.

The development plan for the Stage II field, WZ 12-8 East, is ongoing and is scheduled for completion by Q4 2014. The WZ 12-8 East field is expected to be a phased development, initially comprising three production wells and will utilise a leased mobile production platform. Production will tie-in to the existing processing facility on site.

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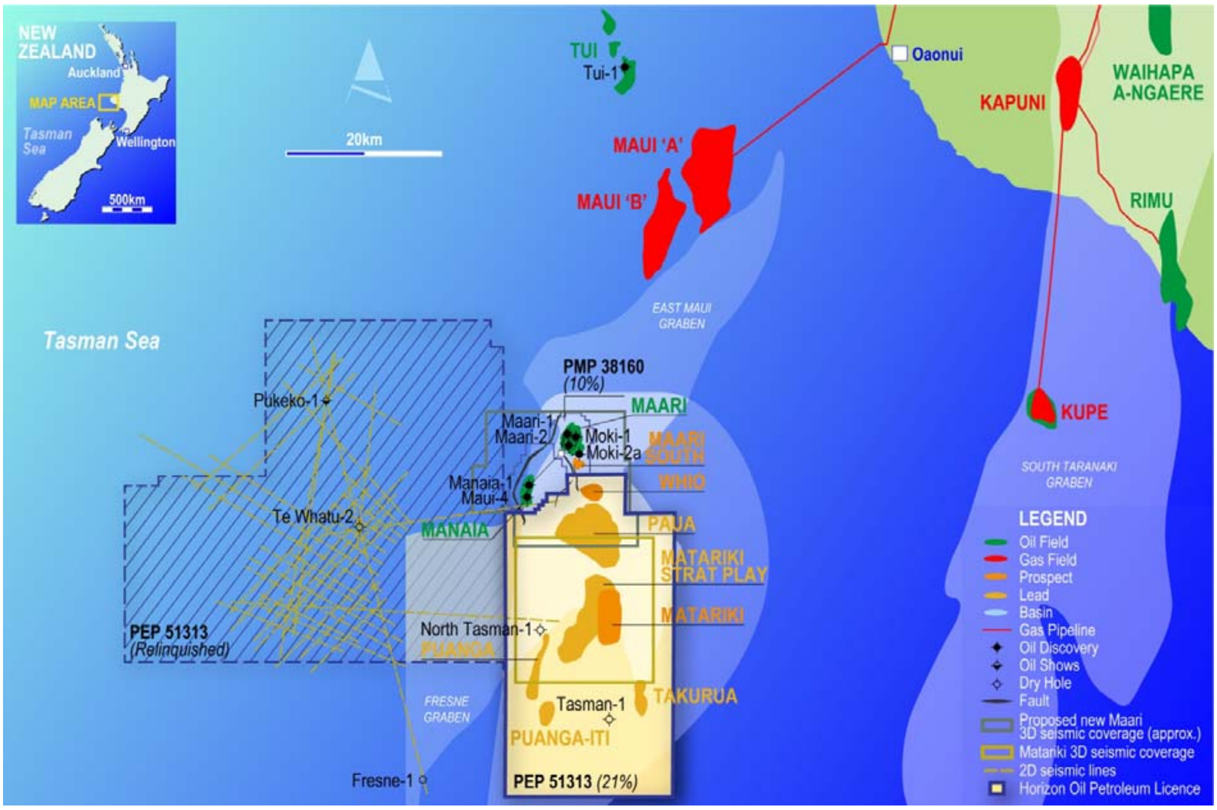
[8] Horizon Annual Report 2013
[9] Horizon company announcement, 30 April 2014
[10] Horizon Annual Report 2013
[11] Horizon investor presentation, May 2014

2.2.2 Maari and Manaia Fields, New Zealand

The Maari and Manaia fields are located in the PMP 38160 permit area approximately 80km offshore Taranaki, New Zealand. The project currently produces oil from three reservoirs; two in the Maari field and one in the Manaia field. For the quarter ended 31 March 2014, average gross production from the project was 9,814 bopd. Production from the three producing reservoirs ties-in to a single wellhead platform located adjacent to the Maari field, before connecting to a Floating Production Storage and Offload vessel (FPSO) moored approximately 1.5km from the wellhead platform. A semi-submersible rig was secured in 2013 to evaluate prospects in the Manaia field and, in 2014, to drill the Whio prospect located in the PEP 51313 permit area, south of the Maari field.

The locations of these fields are set out in the figure below.

Figure 3



Source: Horizon

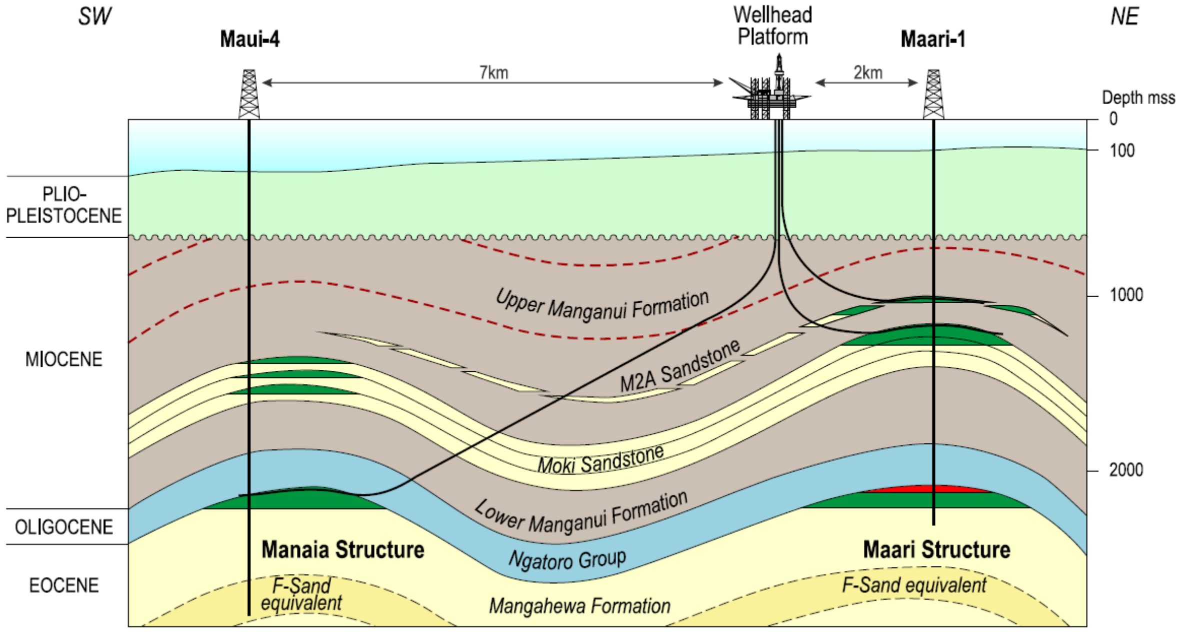
Horizon currently holds a 10% interest in the producing assets at the Maari and Manaia fields, which are operated by OMV New Zealand. Horizon acquired its initial interest in the fields from OMV New Zealand following the divestment by OMV New Zealand of its interest in the PMP 38160 and PEP 38413 permits in January 2003. Following the acquisition, Horizon participated in the drilling of the Maari-2 appraisal well within PMP 38160, which spudded in January 2003, resulting in the commencement of development activities. The New Zealand Government's Ministry of Economic Development granted a Petroleum Mining Permit to the joint venture in December 2005, granting the rights to produce for a period of 22 years in the area comprising PMP 38160.

The Manaia field was initially located within PEP 38413, which is adjacent to the PMP 38160 permit area. An appraisal well, Manaia-1, was drilled in the area and was spudded in August 2009. Following this development, a request was made by the joint venture to extend the area of PMP 38160 to include the area of PEP 38413 containing the Manaia field. On 1 July 2010, the New Zealand Crown Minerals Group approved the request, effectively consolidating the joint venture's development assets into one permit area.

The Maari field was developed via a single wellhead platform connected to an FPSO by subsea umbilical flow lines. The wellhead was installed at Maari-2 in late 2008 and became fully operational in December 2009. The FPSO used in production was initially leased by the joint venture, with the option to purchase the vessel at a later date. The joint venture exercised this option in March 2013, purchasing the vessel for USD 33 million.

Subsequent to production being achieved from the Maari-Moki reservoir, the joint venture successfully began production from two additional wells, Manaia-1 and MR-9, in 2010. The MR-9 well was drilled as a development well to access the M2A sands above the main Moki reservoir at Maari, initially encountered in the Maari-1 well. The Manaia-1 well was drilled as a development well to access the Mangahewa sands at Manaia, initially encountered in the Maui-4 exploration well. The figure below outlines the cross section of the Maari and Manaia fields.

Figure 4



Source: Horizon Annual Report 2013

Since commercialisation, the majority of production has been derived from the five production wells, which draw on the reserves from the Moki formation in the Maari field.

An extensive re-development plan for the Maari and Manaia fields began in late 2013, involving the drilling of an additional exploration/appraisal well, Manaia-2, on the Manaia structure, the reconfiguration of the existing water injection wells and the addition of one new injector, and the drilling of four new production wells in the Maari (3) and Manaia (1) fields. These wells will tie-in to the existing wellhead platform which services the existing production wells.

Since the commencement of production at the Maari and Manaia fields, a number of issues have resulted in periods of lower than expected production yields. The unreliable performance of downhole pumps, as well as scale build-up in well completions, caused interruptions to production in FY2013[12]. In addition, upgrade works and repairs to the project's FPSO resulted in the shutdown of production facilities for a period of approximately five months between July 2013 and December 2013.

A review of the project's reserves was conducted by an independent expert in late 2013. The review resulted in a preliminary downgrade in Horizon's project reserves, on a net basis, from 8.6 mmbbl to 6.0 mmbbl. These reserves will be revised once again upon completion of re-development drilling.

2.2.3 Stanley field, PNG

The Stanley field is a gas / condensate field lying in the PDL 10 (formerly PRL 4, following the issue of the development licence by the PNG Government on 30 May 2014) permit area in the Western Province of PNG. The project currently operates as a joint venture, of which Horizon holds a 30% interest. The PNG Government has the right to participate up to a 22.5% equity interest in the project through a state nominee, upon the

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[12] Horizon has a June financial year end

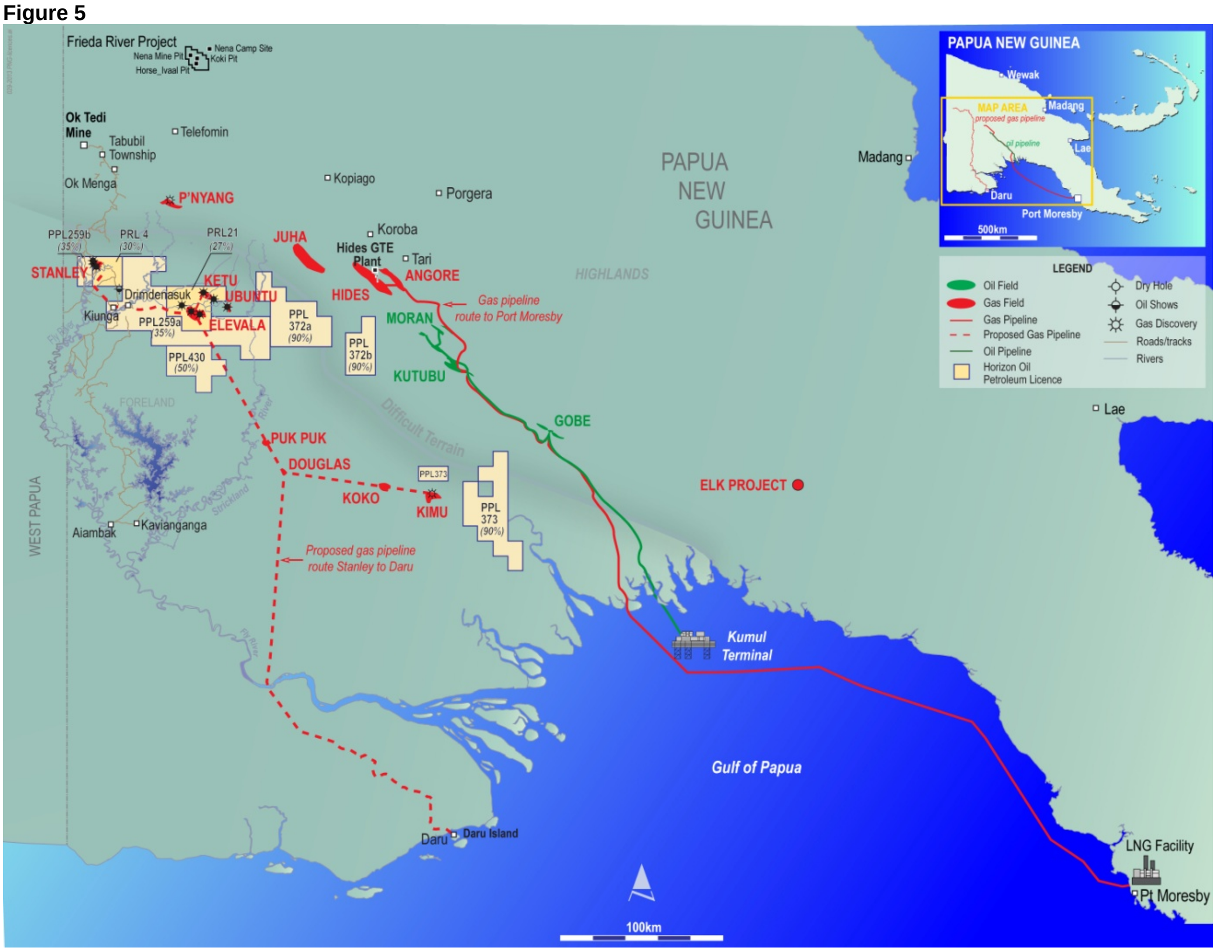
awarding of a PDL for the project. In this event, Horizon's interest in the Stanley project will be diluted to 23.25%.[13]

The Stanley development project is at an advanced stage, with a defined resource. An application for project development was submitted to the PNG Government in August 2012, and was subsequently approved in April 2014. It is expected that the licence will be issued in mid-2014. The project's development plan involves producing 140 million cubic feet of wet gas per day, from which approximately 4,000 barrels of condensate will be recovered per day utilising a two train refrigeration plant located in the field. Any dry gas not sold or used will be re-injected into the reservoir until required for sale. The condensate will be transported via a 40km pipeline to a storage facility at Kiunga, before being loaded onto a special purpose 33,000 barrel tanker 1km downstream of the existing Kiunga wharf for transport to regional customers.[14]

In addition to domestic sales, Horizon plans to leverage the additional capacity created by the development of its fields in the PRL 21permit area to participate in the development of a mid-scale LNG facility that would be located at Daru Island, as shown in the figure below. There is also a possibility of selling gas to third party LNG facilities, including ExxonMobil's LNG Project in Port Moresby, or the potential Total/InterOil Elk-Antelope LNG Scheme.

The figure below outlines the location of the project and the associated proposed infrastructure.

Figure 5



Source: Horizon website

Following the withdrawal of Santos, Carnarvon Petroleum and AWE in 2006, Horizon's participation in PDL 10 increased to 27.95%. The remaining participants, InterOil (43.13%) and Austral Pacific (28.92%), sold their interests to Horizon in 2008, resulting in Horizon holding 100% of the project, before Horizon sold a 50%

[13] Ibid.

[14] Horizon investor presentation, May 2014

interest in PDL 10 to Talisman Energy in 2009 for a total consideration of USD 60 million. Subsequent to this transaction, Talisman sold a 10% in interest in PDL 10 to Mitsubishi Corporation in 2012.

Horizon, as project operator, began drilling the first appraisal well, Stanley-2, in December 2010. The well confirmed 23 metres of net gas / condensate pay in the Toro formation and intersected a new zone with 43 metres of net gas/condensate pay in the Kimu sandstone of the Imburu formation. This new zone was appraised with the drilling of the Stanley-4 well, the results of which confirmed previous findings.

Following positive drilling results and a favourable resource assessment, Final Investment Decision (FID) on the development of the PDL 10 assets was approved by the Horizon board in January 2012 and the joint venture in July 2012, with some contingent resources consequently reclassified to reserves.

Horizon has identified a number of options for the sale of gas production from the Stanley project, in addition to selling gas production via a mid-scale LNG facility. Horizon is in negotiations to supply gas to the Ok Tedi copper and gold mine, also for power generation. The Ok Tedi mine is located less than 100km from the Stanley field. Other options, including the supply of gas to local power stations supporting towns and communities in the region, are also being explored[15]. The nearby Frieda River copper and gold project, currently in the feasibility stage, could also potentially use the Stanley field gas.

In May 2013, Horizon announced that it had entered into an agreement with Osaka Gas to sell a 40% interest in its PNG assets, including PDL 10, for a total consideration of USD 204 million, with approximately USD 78 million to be received following the granting of the Stanley development licence[16] (received on 30 May 2014).[17] The remainder is receivable upon FID of an LNG project. Horizon plans to use its alliance with Osaka Gas to progress the development of a mid-scale LNG facility. Osaka Gas is the second largest gas company in Japan, importing over 8 million tonnes of LNG annually. The company also has an interest in six LNG carriers and is the owner and operator of LNG terminals and a 60,000km pipeline network throughout Japan.

2.2.4 Elevala and Ketu fields, PNG

Elevala and Ketu are two gas / condensate fields located in the PRL 21 permit area, which lies adjacent to Horizon's Stanley field in the PDL 10 permit area. Horizon currently holds a 27% interest in the fields following the transaction with Osaka Gas announced in May 2013. The fields are currently in the advanced stages of appraisal, with the development and pipeline applications submitted to the PNG Government in Q3 FY2014. Horizon is of the view that combined gas volumes from the PDL 10 and PRL 21fields are approaching the scale required for Horizon to participate in the development of mid-scale LNG project in the region.

As operator, Horizon drilled an appraisal well, Elevala-2, in November 2011. The well encountered 18 metres of gas / condensate and indicated that the field extended further north than previously thought. A second well (Elevala-2 ST1) was subsequently drilled, which confirmed the previous discovery at Elevala-2.

Exploration of the Ketu field commenced in March 2012 with the drilling of the Ketu-2 well. Drilling of the appraisal well resulted in surface gas flow at a rate over 20 mmscfd. In August 2013, the Tingu-1 exploration well was drilled, resulting in the discovery of gas/condensate and identification of an accumulation potentially similar in size to the Elevala field[18]. The Tingu-1 well is located approximately 9km from Elevala-2 and is structurally connected to the Elevala field. Development planning of the PRL 21 fields continued subsequent to these developments, resulting in the submission of petroleum development and pipeline applications to the PNG Government.

The project's development concept includes an on-site processing facility for all productions wells. Similar to the Stanley project, condensate will be transported to the Kiunga storage load out facility via a proposed pipeline from the project site.

[15] Horizon Annual Report 2013

[16] Horizon company announcement, 23 May 2013

[17] USD 21 million was received by way of deposit in 2013, with the balance of USD 54 million to be received on receipt of the licence from the PNG Government. In addition, Horizon will also receive approximately USD 24 million in recognition of costs incurred since 1 January 2013. Therefore, the remaining cash payment totals approximately USD 78 million. Approximately USD 77 million of this was paid to Horizon on 12 June 2014, with a further USD 1 million (approximately) to be received in the short term

[18] Company announcement, 28 October 2013

2.2.5 Other PNG exploration assets

In FY2013, Horizon purchased a 90% interest in PNG gas / condensate permits PPL 372 and PPL 373 and was also awarded a 50% interest in PPL 430. As a result of the Osaka Gas Transaction in May 2013, Osaka Gas has the right to acquire a 40% equity interest in these assets, at its option. Horizon also holds a 35% interest in the PRL 259 permit area, along with Osaka Gas which holds a 10% interest.

2.3 Capital structure and shareholders

Horizon had the following securities on issue as at 16 May 2014:

- 1,301,981,265 fully paid ordinary shares
- 1,500,000 partly paid ordinary shares
- 61,223,306 unlisted share options.

Partly paid shares relate to ordinary shares issued on the exercise of employee options. The outstanding obligation in relation to partly paid ordinary shares is payable either when called or by the date not exceeding five years from the grant date of the option which gave rise to the partly paid ordinary share.

The following table lists the substantial shareholders of Horizon as at the date of this report:

Table 9

Shareholder	Number of shares held	% of issued shares
Austral-Asia Energy Pty Limited as trustee for Triplex Global Ventures Limited	319,695,688	25%
Commonwealth Bank of Australia	144,984,627	11%
Tribeca Investment Partners Pty Limited	68,387,994	5%
Subtotal	**533,068,309**	**41%**
Other	768,912,956	59%
Total	**1,301,981,265**	**100%**

Source: Horizon

Horizon issues shares to employees under Employee Option Schemes and to senior executive employees under the Long Term Incentive Plan. It has also issued options to third parties (referred to as General Options).

The following table summarises the unlisted share options on issue as at 16 May 2014:

Table 10

Issue date	Number of options outstanding	Exercise price (AUD)	Barrier price (AUD)	Expiry date
Employee Options[1]				
25-Sep-09	5,175,000[5]	0.29	0.37	25-Sep-14
25-Sep-09	350,000[5]	0.29	0.37	25-Sep-14
09-Oct-09	2,700,000[5]	0.31	0.37	09-Oct-14
16-Sep-10	350,000[5]	0.30	0.35	16-Sep-15
28-May-12	1,666,667[5]	0.26	0.34	28-May-17
17-Sep-12	500,000[5]	0.29	0.37	17-Sep-17
20-Feb-13	350,000	0.43	0.51	20-Feb-18
20-Feb-13	350,000	0.40	0.48	20-Feb-18
Total	**11,441,667**			
General Options[2]				
11-Dec-09	500,000[5]	0.34	0.43	11-Dec-14
06-Jun-11	15,000,000[3]	0.36	-	30-Jun-14
10-Jan-12	1,000,000[5]	0.21	0.26	10-Apr-15
28-May-12	2,000,000[5]	0.26	0.34	27-Aug-15
Total	**18,500,000**			

Issue date	Number of options outstanding	Exercise price (AUD)	Barrier price (AUD)	Expiry date
SARs[4]				
01-Oct-10	6,693,828[5]	n/a	-	01-Oct-15
05-Aug-11	6,478,276[5]	n/a	-	05-Aug-16
13-Aug-12	9,561,936[5]	n/a	-	13-Aug-17
19-Aug-13	8,547,599[5]	n/a	-	19-Aug-18
Total	**31,281,639**			
Total unlisted options	**61,223,306**			

Source: Horizon
Notes:
1. *Employee options relate to options issued to employees under Horizon's Employee Performance Incentive Plan*
2. *General options relate to options issued to third party consultants*
3. *Relates to options issued to Petsec as part of consideration for the acquisition of Petsec's interest in Block 22/12. These options expired on 30 June 2014*
4. *No price is payable by a participant on the exercise of a SAR*
5. *These options have satisfied their barrier prices.*

In relation to the Employee Options:

- each option entitles a Horizon employee to subscribe for one share in Horizon and each option expires five years from the date of issue
- the employee is required to pay AUD 0.01 of the exercise price upon exercise of the option, with the balance to be paid at the expiration of the period that is five years from the date of issue of the option
- the exercise price is the greater of:
  - the price determined by the Board, but will not be less than the five-day VWAP of Horizon shares prior to the date on which the Board resolved to grant the options; and
  - AUD 0.20 per option
- options are classified as barrier options, meaning a holder cannot exercise them (after the vesting period) unless the five-day VWAP of Horizon's shares equals or exceeds a share price "hurdle", determined by the Board at the date of granting the options. Subject to the hurdle price being met, the options are exercisable in three equal tranches from dates which are 12 months, 24 months and 36 months after the grant date.

In relation to the General Options:

- the options issued to Petsec (15 million options) are not performance-based options. These options were exercisable, at Petsec's option, at any time up to and including the expiry date, being 30 June 2014. These options have now expired and were not exercised
- the remainder of General Options have similar performance terms to those of Employee Options.

In relation to the SARs:

- a SAR entitles the holder to receive either, or both, a cash payment or shares in Horizon, as determined by the Board, subject to Horizon satisfying certain performance hurdles
- no price is payable by the holder on the exercise of the right
- the number of SARs that vest is determined by reference to Horizon's "Total Shareholder Return", which measures the performance of Horizon's share price relative to the S&P/ASX200 Energy Index, having regard to minimum and maximum benchmarks (e.g. only 50% will vest subject to the share price as at the testing date equalling the benchmark)
- the amount of the cash payment / number of shares issued is based on the value of the right at the time it is exercised. The value of the right is the excess of the ten-day VWAP of shares prior to the "Effective Allocation Date" of the rights, which is generally the grant date of the rights.

2.4 Share price performance

The share price movements and trading volumes of Horizon up to announcement of the Proposed Scheme are presented graphically in the figure below.

Figure 6

Source: Capital IQ

Table 11

Notes	Date	Comments
1	27-Jan-12	Horizon announced the approval of the FID for the Stanley field gas condensate recovery project in PNG
2	27-Feb-12	Chinese Government's State Oceanic Administration approved the Environmental Impact Assessment for the Beibu Gulf project in China
3	04-May-12	Horizon provided a progress report on the Ketu-2 appraisal well in PRL 21, PNG, outlining a program to establish a stable maximum gas rate before performing multi-rate test to establish the well's capacity profile
4	10-Oct-12	ROC announced the discovery of oil at WZ 6-12N-1, the first of three exploration wells at the Beibu Gulf project
5	05-Nov-12	ROC announced the discovery of oil at WZ 6-12-A6, the second of three exploration wells at the Beibu Gulf project
6	21-Nov-12	Horizon announced the near-completion of the construction and installation phase of the Beibu Gulf Stage I development program
7	15-Mar-13	Horizon is added to the S&P / ASX 200 Index following the closing of trading on 15 March 2013. The large volume of trading likely relates to the purchase of Horizon stock by funds following the S&P / ASX 200 Index
8	22-Mar-13	Horizon announced the commencement of production from the Beibu Gulf project in China
9	22-Apr-13	Horizon acquires additional exploration acreage in PNG in the form of a 50% interest in licence PPL 430 and a 90% interest in PPL 372 and PPL 373
10	20-Jun-13	Horizon announced the completion of the development drilling program from the WZ 6-12 fields, and that a jack-up drilling rig had moved to the WZ 12-8W field
11	31-Jul-13	Horizon announced a fully underwritten 1 for 7 entitlement offer to raise USD 53.5 million. The entitlement offer price of AUD 0.33 represented a 10.8% discount on Horizon's closing share price on 30 July 2013
12	03-Sep-13	Shares issued subsequent to the successful completion of the retail entitlement offer, as announced by Horizon on 28 August 2013
13	11-Nov-13	Horizon announced results from production testing of the Ketu-2 appraisal in PRL 21, PNG. The announcement outlined the company's intention to apply for a development licence for development of the PRL 21 fields in March 2014
14	14-Apr-14	Horizon announced the approval of the Stanley gas/condensate project in PDL 10 by the PNG Government
15	29-Apr-14	Horizon and ROC announced the Proposed Scheme

Source: ASX announcements

2.5 Financial performance

Historical income statements of Horizon are summarised in the table below.

Table 12

(USD million)	Audited FY2012	Audited FY2013	Reviewed 1H2014
Production (mmboe)	*0.43*	*0.47*	*0.64*
Average realised sales price (USD / mmboe)	*116.62*	*102.75*	*105.68*
Revenue	50.4	48.1	64.8
Cost of sales (including amortisation)	(16.9)	(22.7)	(49.7)
Gross profit	**33.5**	**25.4**	**15.1**
EBITDA	**37.7**	**27.3**	**28.6**
Depreciation / amortisation	(8.1)	(9.1)	(18.2)
EBIT	**29.6**	**18.2**	**10.4**
EBITDA margin	*75%*	*57%*	*44%*
EBIT margin	*59%*	*38%*	*16%*

Source: Horizon Annual Report 2013; Horizon Interim Report 2014

We note the following in relation to the financial performance of Horizon presented above:

- reported revenues for the six months ended 31 December 2013 were largely comprised of sales from the Beibu Gulf project (c.USD 60 million). Sales from the Maari field project in New Zealand decreased by c.USD 14 million on the same period in the prior year, which was largely driven by a project shut-in for field maintenance and upgrade works
- a decrease in EBITDA between FY2012 and FY2013 was driven by the ramp-up effect of commencing operations at the Beibu Gulf project as well as a decrease in the average realised sale price achieved, net of hedging, by 12%, as well as the ramp-up effect of commencing operations at the Beibu Gulf project. In comparison, crude oil prices decreased by approximately 15% over this period
- general and administrative expenses approximated USD 7 million in FY2013, whilst exploration expenses totalled USD 0.6 million
- depreciation and amortisation of USD 18 million for the six months ended 31 December 2013 (compared to USD 2 million on a like-for-like basis) was mostly comprised of amortisation of Block 22/12 as a result of the commencement of production in the field.

2.6 Financial position

Summarised recent balance sheets of Horizon are shown in the table below.

Table 13

(USD million)	Audited 30-Jun-2013	Reviewed 31-Dec-2013
Cash and cash equivalents	19.0	37.1
Trade and other receivables	19.0	22.2
Other current assets	9.4	8.7
Total current assets	**47.4**	**68.0**
Oil and gas assets	317.6	340.0
Exploration phase expenditure	92.5	112.8
Deferred tax assets	10.4	7.3
Other non-current assets	8.3	8.0
Total non-current assets	**428.8**	**468.1**
Total assets	**476.2**	**536.1**
Trade and other payables	40.2	44.9
Borrowings	14.7	55.1
Current tax payable	0.8	0.0
Other current liabilities	1.2	15.6
Total current liabilities	**56.9**	**115.6**
Trade and other payables	21.3	21.1
Derivative financial liabilities	0.0	1.0
Borrowings	180.8	143.9
Deferred tax liability	17.1	15.3
Long-term provisions	15.7	15.5
Other financial liabilities	17.4	14.6
Total non-current liabilities	**252.3**	**211.4**
Total liabilities	**309.2**	**327.0**
Net assets	**167.0**	**209.1**

Source: Horizon Annual Report 2013; Horizon Interim Report 2014

We note the following in relation to the balance sheets of Horizon presented above:

- the increase in cash and cash equivalents for the six months ended 31 December 2013 was driven by:
  - an entitlement offer completed in August 2013, in which Horizon raised approximately AUD 54 million via a fully underwritten non-renounceable entitlement offer, resulting in the issue of 162.2 million shares at a price of AUD 0.33 per share, which represented a discount of 10.8% to the closing share price prior to the announcement of the entitlement offer
  - the commencement of production at the Beibu Gulf project
- proceeds from Horizon's sale of a 40.0% interest in its PNG gas / condensate assets to Osaka Gas, totalling USD 204 million, have been treated as a contingent asset in Horizon's interim financial statements (meaning they are not recognised on the balance sheet, requiring only disclosure under relevant accounting standards). USD 54 million of these proceeds with an additional USD 24 million (approximately) in past costs are payable to Horizon on the granting of a development licence for the Stanley project (which was received on 30 May 2014), with the balance payable upon FID for an LNG facility

- non-current trade and other payables includes a deposit of USD 20.4 million provided by Osaka Gas at the time of entering into the sale agreement in May 2013.The agreement provides up to 24 months for the conditions of sale to be satisfied.
- exploration phase expenditure refers to capitalised expenditure incurred by Horizon in China, New Zealand and PNG
- oil and gas assets refer to the book value of Horizon's producing and development assets in China, New Zealand and PNG. Of the USD 317 million in oil and gas assets as at 30 June 2013, USD 102 million related to producing assets and USD 215 million related to Horizon's development assets.
- Oil and gas assets increased in the six month period ended 31 December 2013 by an amount of USD 22 million, which relates to capitalised expenditure on producing and development stage assets
- current borrowings increased by USD 40 million between 30 June 2013 and 31 December 2013 as debt became current in accordance with the lending terms. Since issuing its interim report, Horizon and renegotiated the terms of its debt such that only USD 10 million is now current.

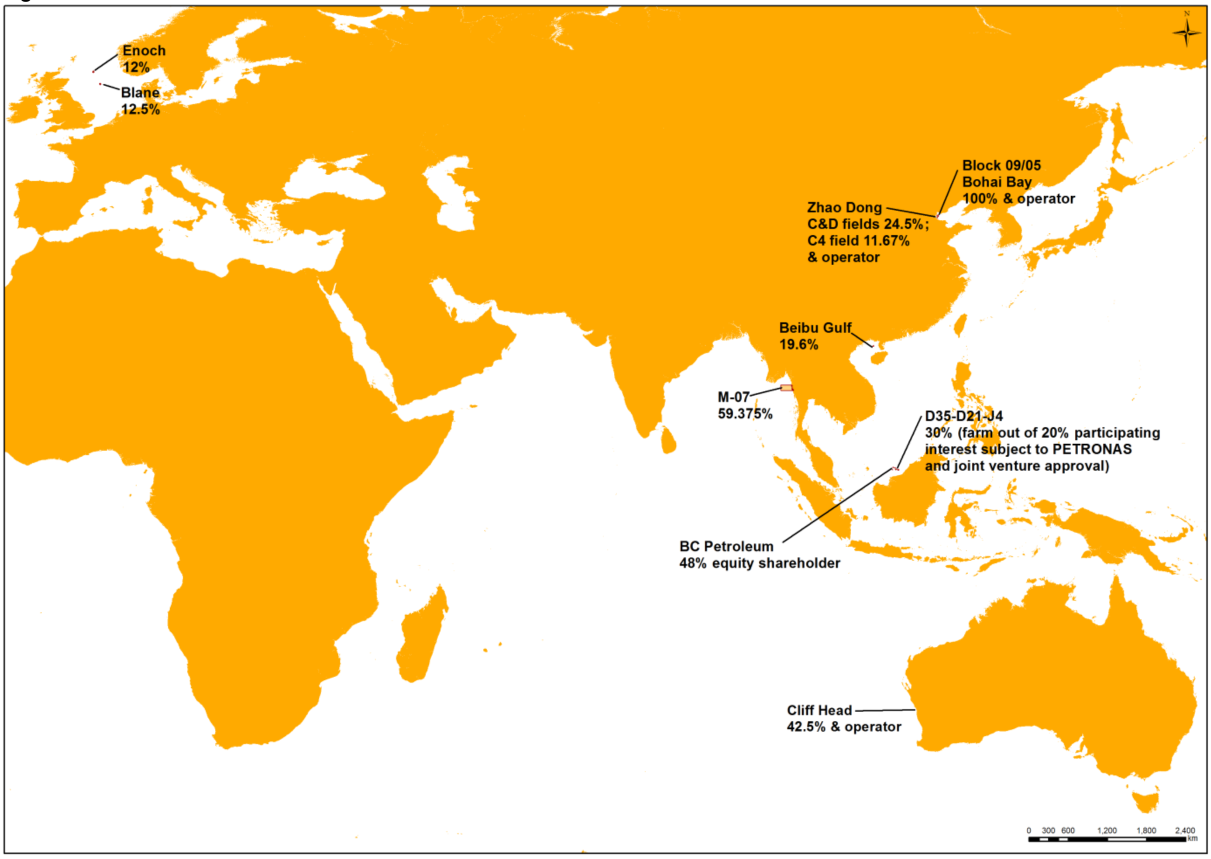
  In addition, Horizon drew a letter of credit in the amount of USD 20.4 million, relating to a refundable deposit paid by Osaka Gas as part of the Osaka Gas Transaction agreed in May 2013. This letter of credit does not form part of borrowings recognised on the balance sheet and will be released on completion of the transaction (expected in mid-2014)
- Horizon's non-current borrowings as at 31 December 2013 comprised USD 114 million, relating to the Company's reserves based debt facility, and an amount of USD 84 million in Convertible Bonds. We note the following:
  - Horizon issued 400 Convertible Bonds for USD 80 million on 17 June 2011. The bonds have a coupon rate of 5.50%
  - the bonds were issued with an initial conversion price of USD 0.52, although subsequent share issues have resulted in an adjustment in conversion price to USD 0.409 as at 31 December 2013
  - the maturity date of the bonds is 17 June 2016 when they will be redeemed at 108.8% of their principal amount
  - the bonds are convertible, at the option of the holder, during the period up to and including the close of business on the seventh day prior to the maturity date, into fully paid ordinary shares. As a consequence, Horizon treats the optionality component of the bonds as a derivative financial liability (comprising the "other financial liabilities" of USD 15 million itemised in the balance sheet)
  - no bonds had been converted or redeemed as at 31 December 2013
- other current liabilities as at 31 December 2013 include a restoration provision of USD 11 million in relation to the Beibu Gulf project, reflecting 2013 accumulated costs yet to be called, plus costs forecast for 2014. Chinese legislation requires restoration costs be incurred over the remaining life of the field, rather than at the end of the assumed life
- other current liabilities as at 31 December 2013 also include an amount of USD 5 million for derivative financial instruments. Horizon currently utilises derivative instruments, in the form of commodity options, to hedge against fluctuations in commodity prices.

3 Profile of ROC

3.1 Company overview

ROC is an upstream oil and gas company based in Australia, which was established in late 1996 and listed on the ASX in 1999. The company is headquartered in Sydney with regional offices in Perth, Beijing and Kuala Lumpur. ROC operates major oil and gas production, exploration and development assets in Australia, China and Malaysia. The major producing fields in which ROC owns interests comprise the Cliff Head oil field in Australia and the Zhao Dong C&D and C4 oil fields and the Beibu Gulf, located offshore China. These fields accounted for 92% of ROC's production in 2013[19].

Figure 3



Source: Scheme Booklet

[19] ROC 2013 Annual Report

3.2 Principal assets

The portfolio of major assets held by ROC is summarised in the following table.

Table 14

Asset	Location	% ownership	Other owners	Operator	Type of project
Operating assets					
D35/D21/J4 PSC[1]	Malaysia	30.0%	PETRONAS Carigali (40%) E&P Malaysia Venture Sdn Bhd (10%) Dialog Resources Sdn Bhd (20%)	PETRONAS Carigali	Oil and gas
Balai Cluster RSC	Malaysia	48.0%	Dialog D & P Sdn Bhd (32%) PETRONAS Carigali (20%)	BC Petroleum[2]	Oil and gas
Blane	UK	15.24%/ 12.5%[3]	Talisman Sinopec Energy (UK) Limited (25%) Talisman Energy Norge AS (18.4%) Dana Petroleum (BVUK) (12.5%) Faroe Petroleum (UK) Limited (18%) JX Nippon Exploration and Production (UK) Limited (14%) (These percentages are unitised)	Talisman Energy Norge AS (Field operator) Talisman SinopecEnergy (UK) Limited (Wells operator)	Oil and gas
Enoch	UK	15.0%/ 12.0%[3]	Talisman Sinopec North Sea Limited (25.2%) Dana Petroleum (BVUK) Limited (20.8%) Endeavour Energy UK Limited (8.0%) First Oil Expro Limited (14.0%) Statoil Petroleum AS (11.78%) Noreco Oil AS (4.36%) DetNorkse AS (2.0%) Faroe Petroleum AS (1.86%) (These percentages are unitised)	Talisman Sinopec North Sea Limited	Oil and gas
Cliff Head	Australia	42.5%	AWE (57.5%)	ROC	Oil
Bohai Bay – ZhaoDong C&D fields	China	24.5%	PetroChina (51.0%) New XCL-China (24.5%)	ROC	Oil and gas
Bohai Bay – ZhaoDong C4 field	China	11.67%[4]	PetroChina (76.7%) New XCL-China (11.7%)	ROC	Oil and gas
Beibu Gulf – Block 22/12 (WZ 6-12, WZ 12-8 West)	China	19.6%[5]	CNOOC (51.0%) Horizon Oil (26.95%) Oil Australia (2.5%)	CNOOC	Oil and gas
Exploration assets					
Bohai Bay – Block 09/05	China	100.0%[6]	-	ROC	Oil and gas
Bohai Bay – Zhanghai & Chenghai Blocks	China	39.2%[7]	PetroChina (51.0%) New XCL-China (9.8%)	ROC	Oil and gas
Beibu Gulf – Block 22/12 (WZ 12-8 East)	China	40.0%[9]	Horizon Oil (55%) Oil Australia (5%)	ROC	Oil and gas
Block M07[8]	Myanmar	59.37%	Tap Oil Limited (32.62%) Smart E&P International Limited (5%)	ROC	Gas

Source: ROC Annual Report 2013; ROC Oil website
Notes:
1. *ROC has noted its intention to farm out a 20% participating interest in D35/D21/J4 PSC, effective 1 January 2014, subject to approval from PETRONAS. The 30% participating interest represents ROC's interest post farm-out*
2. *BC Petroleum was formed as a joint venture company by ROC, Dialog D & P and PETRONAS Carigali, responsible for operating and managing the Balai Cluster RSC oil and gas field*
3. *Unitised interest*
4. *Unitised interest in producing field (pending final Joint Management Committee approval)*
5. *Interest in field development post-government back-in*
6. *Prior to government back-in*
7. *Interest in field development post-government back-in*
8. *Subject to ROC Board approval and finalisation of terms with the Myanmar Ministry of Energy*
9. *Subject to Government back-in.*

A summary of the reserves, resources and prospective resources for ROC as at 1 January 2014 is set out in the table below. The reserves and resources presented below represent ROC's view; refer to the technical expert's report (in Appendix G) for RISC's view on the reserves and resources attributable to the assets.

Table 15

Asset	Country	Oil (mmbbl)	Gas (Bcf)	Total (mmboe)
Proved Plus Probable Reserves (2P)				
Zhao Dong	China	3.6	0.9	3.7
Beibu		4.7	0.0	4.7
Cliff Head	Australia	2.2	0.0	2.2
Blane	UK	1.3	0.1	1.3
Enoch		0.3	0.0	0.3
D35/D21/J4[1]	Malaysia	4.0	6.9	5.2
Total		**16.1**	**7.9**	**17.4**
Proved Plus Probable Contingent (2C)				
Zhao Dong Beibu	China	5.5	1.0	5.7
Cliff Head	Australia	2.3	-	2.3
Blane Enoch	UK	0.9	5.6	1.8
D35/D21/J4[1]	Malaysia	22.1	10.3	23.9
Total		**30.8**	**16.9**	**33.7**
Prospective Resources				
Zhao Dong Beibu	China	31.5	1.3	31.7
Cliff Head	Australia	0.5	0.0	0.5
Blane Enoch	UK	-	-	-
D35/D21/J4[1]	Malaysia	7.2	0.0	7.2
Total		**39.2**	**1.3**	**39.4**

Source: ROC management
Note:
1. *The reserves and resources presented for D35/D21/J4 have been presented on a 30.0% participating interest basis.*

3.2.2 D35/D21/J4 PSC

In April 2014, ROC announced the farm-in to a PSC of the D35/D21/J4 fields, effective 1 January 2014. ROC entered into a joint venture with the existing operator, PETRONAS Carigali, to hold a 50% interest in the fields. ROC has noted its intention to farm-out a twenty percent (20%) participating interest, resulting in a net interest of 30%, subject to approval by PETRONAS and the joint venture.

The D35/D21/J4 fields are located off-shore Malaysia in the western Balingian province of the Sarawak Basin. All three fields have potential near-field exploration with D35 being the largest and longest producing field and D21 and J4 being satellite producing assets.

The fields had a combined daily production rate in April 2014 of approximately 10,000 bopd of oil and gas sales of approximately 17 mmscfd gross working interest.

3.2.3 Balai Cluster RSC

ROC holds a 48% interest in BC Petroleum, a joint venture company created to operate and manage the Balai Cluster Risk Service Contract. The Balai Cluster is situated offshore Sarawak, Malaysia and comprises the Balai, Bentara, Spaoh and West Acis oil and gas fields.

Pre-development activity commenced in 2011 with geological and geophysical works, drilling and testing of appraisal wells and the procurement of related facilities. Drilling concluded in June 2013 with the drilling of five wells in the four fields. The Bentara field development plan was approved in March 2014. Development of the

Bentara field will utilise the existing platform facilities and two wells that were established in the pre-development phase. Production will be processed through the Early Production Vessel and transferred via shuttle tanker to point of sale. The commencement of commercial oil production is expected during the second quarter of 2014.

3.2.4 Blane

The Blane Oil Field commenced production in September 2007 and is located in the Central Graben of the North Sea. Blane contributed 8% of ROC's 2013 production and generated revenue of USD 18.1 million in 2013. The field was developed as a subsea tieback to the BP-operated Ula platform located in the Norwegian continental shelf (34km to the northeast) and comprises two horizontal production wells with gas lift and one water injection well.

Blane Oil Field Development Plan and unitisation agreements were finalised in 2005 with ROC holding a 15.24% license interest in the undeveloped UK portion of the Blane oil field as well as a 12.5% interest in the unitised field. The Blane Oil Field is operated and managed by Talisman Sinopec Energy (UK) Limited and Talisman Energy Norge AS.

3.2.5 Enoch

The Enoch oil and gas field is located in the Central Graben of the North Sea and began production in May 2007. The field was developed as a subsea tie-back to the Marathon-operated Brae-A platform located on the UK continental shelf. However, due to mechanical issues with subsea equipment, the Enoch field was forced to cease production in January 2012. Production is however expected to resume in mid-2014.

ROC holds a 15% interest in the license containing the undeveloped UK portion of the Enoch oil and gas fields and a 12% interest in the unitised field. The Enoch oil and gas fields are operated and managed by Talisman Sinopec North Sea Limited.

3.2.6 Cliff Head

The Cliff Head facilities are located offshore in the Perth Basin, Western Australia within a 72km^2 production license known as WA-31-L in 15-20 metre water depth. The facility is managed and operated by ROC. Oil is transported initially by two 14km pipeline running between the stabilisation plant in Arrowsmith and the unmanned platform offshore, then 350km by truck to the BP refinery in Kwinana.

Figure 3

Source: ROC website

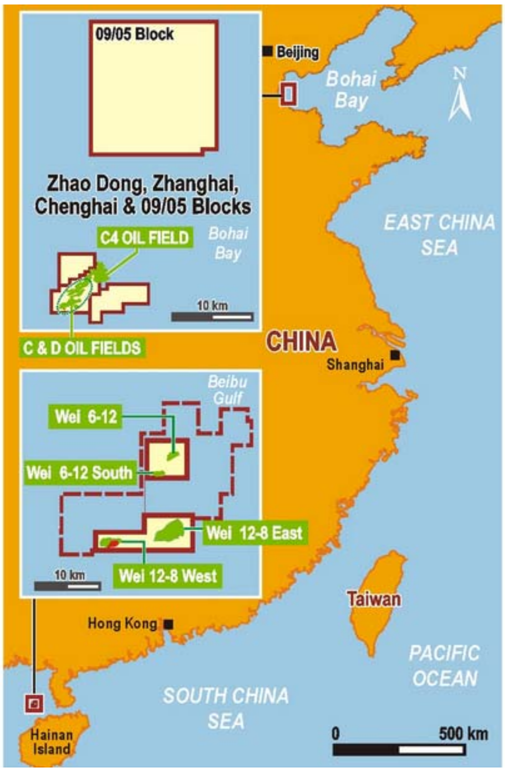
ROC holds a 42.5% interest in the Cliff Head facilities and operates in a joint venture with AWE's subsidiaries which holds the remaining interest.

The Cliff Head oil fields comprise a series of stacked permian sandstone reservoirs within fault and dip-closed structures, sealed by the regional Kockatea Shale. ROC discovered the Cliff Head oil field in 2001 and completed the development of production facilities in December 2005, which included the drilling of eight development wells. The facility has been in production since 2006 and contributed 15% of production and USD 41.1 million in revenue in 2013.

3.2.7 Bohai Bay

The province of Bohai Bay has a stacked reservoir system with rich and generative source rock producing good to excellent quality oil. Bohai Bay is located offshore China and comprises four separate sites. The figure below shows the location of the individual sites.

Figure 5



Source: ROC website

ROC holds a production license in the Zhao Dong Block, which covers an area of 27.5km^2. Zhanghai, Chenghai and 09/05 are the three remaining blocks located in Bohai Bay and are currently in the exploration and appraisal phase.

ROC acquired the Zhao Dong Block through its acquisition of Apache China Corporation LDC in 2006. Zhao Dong Block comprises of the C&D and C4 fields. ROC holds a 24.5% development interest in the C&D fields and an 11.67% interest in the unitised interest of the C4 field. The Zhao Dong Block contributed 55% of ROC's total production and USD 134.7 million of revenue in 2013. The offshore facility in the Zhao Dong Block contains drilling, accommodation, production and processing facilities through four bridge-linked platforms. The C4 Field Unit facilities comprise a wellhead platform, utility platform and pipelines to the C&D field platform. The oil is delivered to an onshore processing plant by pipelines.

In March 2011 ROC's existing petroleum contract, which initially covered the Zhao Dong Block, was modified to include the neighbouring Zhanghai and Chenghai Blocks. ROC holds a 39.2% interest in the Zhanghai and Chenghai blocks in a joint venture with PetroChina Company Limited and New XCL-China LLC.

In May 2012 ROC was awarded a 100% interest in the 09/05 exploration Block, which is located approximately 15km north of the Zhao Dong Block. ROC has conducted initial exploration activity with a 3D ocean bottom cable seismic campaign covering an area of 162km^2.

Horizon entered into a seismic farm-in option agreement with ROC in Block 09/05. Under the terms of the agreement, Horizon has elected not to exercise the option in light of the proposed merger with ROC.

3.2.8 Beibu Gulf

The Beibu Gulf assets are operated under a joint venture partnership, in which ROC holds a 19.6% interest in the development and production assets and a 40% interest in the exploration and appraisal assets.

Horizon holds a 26.95% interest in the development and production assets and a 55% interest in the exploration and appraisal assets.

Refer to Section 2.2 under the profile of Horizon for further details relating to the Beibu Gulf assets.

3.2.9 Block M07

ROC was awarded the PSC for Block M07 in March 2014 subject to ROC Board approval and finalisation of the terms with the Myanmar Ministry of Energy. Block M07 is approximately 13,000 km^2 and is located in the Moattama basin, offshore Myanmar. ROC is in a joint venture with Tap Oil Limited and Smart E&P International Limited, in which ROC holds a 59.375% interest and operates the licence. The awarded PSC permits the joint venture partners to undertake an 18 month Environmental Impact Assessment and study period with the option of a subsequent three year exploration work programme.

3.3 Capital structure and shareholders

As at the date of this report, ROC had the following securities on issue:

- 687,618,400 ordinary listed shares
- 300,000 unlisted share options under the Executive Share Option Plan
- 10,715,000 unlisted LTI Rights under existing Long Term Incentive Plan (LTIP) (formerly referred to as Performance Rights)
- 7,527,358 unlisted LTI Rights under the New Long Term Incentive Plan
- 1,886,476 unlisted Deferred STI Rights.

As at the date of this report, ROC had been notified that Allan Gray Australia Pty Limited (formerly known as Orbis Investment Management (Australia) Pty Limited) holds 20.06% of the voting power of ROC.

The following table summarises the unlisted share options on issue as at 31 March 2014.

Table 16

Issue date	Number of securities outstanding	Type of option	Vesting date	Exercise price (AUD)	Expiry date
23-Aug-2008	300,000	Executive Share Options	08-Nov-2012 to 23-Dec-2012	0.73	23-Dec-2014
16-Dec-2011 to 18-Mar-2014	18,242,358	LTI Rights under the LTIP and EIP	16-Dec-2014 to 31-Dec-2016	n/a	16-Dec-2014 to 31-Dec-2016
15-May-2013 & 29-Jan-2014	1,886,476	Deferred STI Rights	31-Dec-2014 to 31-Dec-2015	n/a	31-Dec-2014 to 31-Dec-2015
Rights approved at the AGM					
27-May-2014	1,180,851	LTI Rights		n/a	1-Jan-2014 to 31-Dec-2016
27-May-2014	387,209	Deferred STI Rights		n/a	

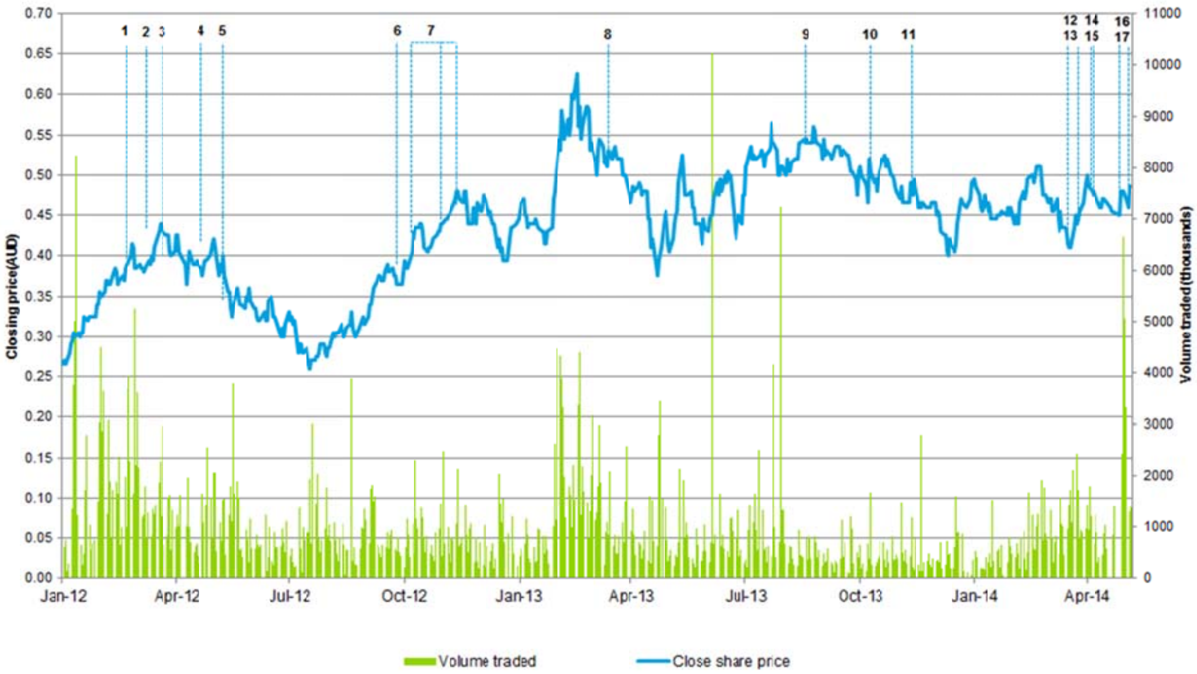
Source: ROC Appendix 3B (8 April 2014); ROC management

For further details of the unlisted share options on issue, refer to the Scheme Booklet.

3.4 Share price performance

The share price movements and trading volumes for ROC up to the announcement of the Proposed Scheme are presented graphically in the figure below.

Figure 6



Source: ASX Announcements; Capital IQ

Table 6

Notes	Date	Comments
1	27-Feb-2012	Chinese Government's State Oceanic Administration approved the Environmental Impact Assessment for the Beibu Gulf project in China
2	23-Mar-2012	ROC announced the withdrawal from PEP52181 offshore Taranaki Basin, New Zealand
3	28-Mar-2012	ROC announced production at Enoch Oil and Gas Field was offline due to mechanical issues with subsea equipment and anticipated to be offline for the remainder of 2012
4	01-May-2012	Issued 729,200 shares in accordance with ROC's Long Term Incentive Plan
5	14-May-2012	ROC awarded petroleum contract with CNOOC for 100% interest in and operatorship of the Bohai 09/05 exploration block
6	2-Oct-2012	Commencement of the exploration drilling programme in Block 22/12 in the Beibu Gulf
7	Oct - Nov-2012	ROC announced the discovery of oil at WZ 6-12N-1, WZ 6-12-A6 and WZ 6-12-A&7 exploration wells at the Beibu Gulf project
8	22-Mar-2013	ROC announced the commencement of production from the Beibu Gulf project in China
9	19-Aug-2013	ROC announced the final stage of the Beibu Gulf development drilling has been concluded
10	10-Oct-2013	ROC announced completion of 09/05 3D ocean bottom seismic campaign in the 09/05 exploration licence in Bohai Bay
11	12-Nov-2013	ROC announced the commencement of the Extended Well Test Programme in the Balai Cluster
12	7-Mar-2014	Issued 106,600 shares, in accordance with ROC's Equity Incentive Plan
13	27-Mar-2014	Tap Oil announced the awarding of a PSC with ROC for Shallow Water Exploration Block M07 in the Moattama basin, offshore Myanmar
14	31-Mar-2014	ROC announced the sale of its 50% participating interest in Basker Manta Gummy (BMG) to Cooper Energy Limited for AUD 1.0 million cash and AUD 5 million contingent consideration, subject to first hydrocarbons from a commercial development
15	1-Apr-2014	ROC announced the farm in to a PSC which includes three fields (D35/D21/J4) located offshore Malaysia. As a result of the farm in, ROC announced an increase of 2P petroleum reserves to 20.9 mmboe
16	24-Apr-2014	ROC announced a trading halt pending the possible release of an announcement in respect to a possible transaction involving Horizon
17	29-Apr-2014	ROC and Horizon announced the Proposed Scheme

Source: ASX announcements

3.5 Financial performance

Historical income statements of ROC are summarised in the table below.

Table 17

(USD million)	Audited CY2012	Audited CY2013
Total working interest production (mmboe)	*2.4*	*2.7*
Average realised sales price (USD / mmboe)	*113.6*	*104.6*
Revenue	242.1	251.0
Operating costs	(135.9)	(154.9)
Gross profit	**106.2**	**96.1**
EBITDA (plus impairments)	**143.5**	**157.1**
EBIT	**85.4**	**65.4**
EBITDA margin	*59%*	*63%*
EBIT margin	*35%*	*26%*

Source: ROC Annual Report 2013

We note the following in relation to the financial performance of ROC presented above:

- ROC reported production costs of USD 51 million in CY2013, which is approximately 30% higher than that reported in the prior year (USD 35.7 million). The increase in production costs is attributable to ROC's increased working interest production, which increased from 2.4mmboe in CY2012 to 2.7 mmboe in CY2013 and the Enoch well head repair cost
- although ROC's production increased in CY2013, the profitability of the major producing assets decreased as a result of a declining average realised sale price over the CY2013 period. ROC's reported CY2013 gross profit of USD 96.1 million, decreased 10.5% compared to CY2012 (USD 106.2 million)
- operating costs consist of production costs, amortisation, movement in stock and overlift and royalties and other levies
- finance costs consist of interest on bank loans, unwinding of the restoration provision and other finance costs. ROC currently holds an undrawn secured bank loan facility of USD 80 million with an amortising facility, maturing in June 2015 with the Commonwealth Bank of Australia, BNP Paribas and Sumitomo Mitsui Banking Corporation with an effective interest rate of 3.7% per annum
- impairment costs for the year end 31 December 2013 totalled USD 6.9 million, which related to ROC's 48% interest in BC Petroleum. The impairment relates to non-recoverable expenditure, mainly interest on bank loans.

3.6 Financial position

Summarised recent balance sheets of ROC are shown in the table below.

Table 18

(USD million)	Audited 31-Dec-12	Audited 31-Dec-13
Cash and cash equivalents	56.8	65.1
Trade and other receivables	25.5	32.4
Inventories	0.6	2.1
Total current assets	**82.9**	**99.6**
Oil and gas assets	237.3	227.2
Exploration and evaluation expenditure	1.1	0.6
Property plant and equipment	1.1	0.9
Deferred tax assets	13.0	20.6
Investments in associate companies	33.4	67.2
Total non-current assets	**285.9**	**316.5**
Total assets	**368.8**	**416.1**
Trade and other payables	36.1	42.2
Current tax liabilities	9.9	8.3
Provisions	10.9	14.2
Total current liabilities	**56.9**	**64.7**
Deferred tax liabilities	26.4	21.1
Long-term provisions	66.9	64.0
Total non-current liabilities	**93.3**	**85.1**
Total liabilities	**150.2**	**149.8**
Net assets	**218.6**	**266.3**

Source: ROC Annual Report 2013

We note the following in relation to the balance sheets of ROC presented above:

- oil and gas assets relate to the exploration development and production assets held by the company. During CY2013, USD 75.5 million of development assets were reclassified as production assets. Key movements in the net balance of the oil and gas assets are as follows:
  - development expenditure on producing assets increased by approximately USD 60.7 million during CY2013
  - amortisation for CY2013 totalled USD 70.8 million
- investments in associate companies relates to ROC's 48% interest in BC Petroleum. ROC made a cash contribution of USD 40.7 million to BC Petroleum during CY2013. Cash contributions are initially recorded as a loan and are converted to equity with shareholder approval
- current and non-current provisions consist of employee benefits and restoration provisions. Provisions for restoration equated to USD 75.4 million for the year end 31 December 2013.

4 Profile of the Proposed Merged Entity

4.1 Overview

The merger of Horizon and ROC will create a company with a market capitalisation in excess of AUD 850 million (based on the aggregation of the two company's current market capitalisations), making the Proposed Merged Entity potentially amongst the top ten largest independent upstream oil and gas companies listed on the ASX.

It will have interests in seven (mainly) oil producing assets (with a consolidated interest of 47% in the producing Beibu Gulf fields), an interest in a significant oil and gas development project in PNG and an exploration portfolio spanning China, New Zealand, Malaysia and PNG.

The merger itself is not expected to immediately generate significant quantifiable synergies beyond some corporate cost savings, however the combination of Horizon and ROC's reserves and resources portfolios and balance sheets is expected to result in a larger, better capitalised investment prospect, compared to Horizon on a standalone basis.

The portfolio of assets held by the Proposed Merged Entity is summarised in the table below:

Table 19

Asset	Location	% ownership	Type of project
Operating assets			
PMP 38160 (Maari/Manaia)	New Zealand	10.0%	Oil
Beibu Gulf – Block 22/12 (WZ 6-12, WZ 12-8 West)	China	46.6%	Oil
D35/D21/J4 PSC[1]	Malaysia	30.0%	Oil and gas
Balai Cluster RSC	Malaysia	48.0%	Oil and gas
Blane	UK	12.5%	Oil and gas
Enoch	UK	12.0%	Oil and gas
Cliff Head	Australia	42.5%	Oil
Bohai Bay – ZhaoDong C&D fields	China	24.5%	Oil and gas
Bohai Bay – ZhaoDong C4 field	China	11.6%	Oil and gas
Development / pre-development assets			
PDL 10 (Stanley)	PNG	30.0%[2]	Condensate and gas
PRL 21 (Elevala, Ketu)	PNG	27.0%[2]	Condensate and gas
Exploration assets			
PEP 51313 (Matariki, Whio)	New Zealand	21.0%/10.0%[3]	Oil
Beibu Gulf – Block 22/12 (WZ 12-8 East)	China	95.0%[4]	Oil
Bohai Bay – Block 09/05	China	100.0%	Oil and gas
Bohai Bay – Zhanghai & Chenghai Blocks	China	39.2%	Oil and gas
PPL 259	PNG	35.0%[2]	Condensate and gas
PPL 372	PNG	90.0%/54.0%[2,5]	Condensate and gas
PPL 373	PNG	90.0%/54.0%[2,5]	Condensate and gas
PPL 430	PNG	50.0%/30.0%[2,5]	Condensate and gas
Block M07[6]	Myanmar	59.37%	Gas

Source: Horizon; ROC
Notes:
1. *ROC has noted its intention to farm out a 20% participating interest in D35/D21/J4 PSC to Dialog Resources Sdn Bhd, effective 1 January 2014, subject to approval from PETRONAS.30% participating interest represents ROC's interest post Dialog farm-in*
2. *Subject to reduction to allow for PNG State Nominee participation at 22.5%*
3. *In the event of a commercial discovery at Whio, Horizon's interest will reduce to 10%*
4. *Subject to reduction to allow for CNOOC participation at 51%*
5. *Subject to a reduction to allow for Osaka Gas to participate up to 36%, at Osaka Gas' option*
6. *Subject to ROC Board approval and finalisation of terms with the Myanmar Ministry of Energy.*

4.2 Capital structure

The capital structure of the Proposed Merged Entity, including substantial shareholders following implementation of the Proposed Scheme, is summarised out below:

Table 20

	Section reference	Unit		Calculation
Number of shares in Horizon	2.3	'000s	1,301,981	(a)
Number of shares to be converted into Horizon on exercise of Petsec options[1]	2.3	'000s	15,000	(b)
Total number of shares forecast to be issued in Horizon		**'000s**	**1,316,981**	**(c) = (a) + (b)**
IMC / Austral-Asia	2.3	'000s	*319,696*	(d)
Number of shares in ROC	**3.3**	**'000s**	**687,618**	**(e)**
Allan Gray Australia Pty Limited	3.3	'000s	*137,907*	(f)
Proposed merger ratio (shares in ROC to be issued per share held in Horizon)		**#**	**0.724**	**(g)**
New shares to be issued in ROC		'000s	953,494	(h) = (c) x (g)
Total shares in Proposed Merged Entity (on an undiluted basis)		**'000s**	**1,641,113**	(i) = (e) + (h)
Shares held by Horizon shareholders			58%	= (h) ÷ (i)
IMC / Austral-Asia			*14%*	= {(d) x (g)} ÷ (i)
Shares held by ROC shareholders			42%	= (e) ÷ (i)
Allan Gray Australia Pty Limited			*8%*	= (f) ÷ (i)

Source: Horizon; Deloitte Corporate Finance analysis
Note:
1. *We assumed that these options would be exercised prior to their recent expiry on 30 June 2014, however we understand that this has not taken place as at the date of this report. However, we have not updated our valuation to reflect this as it does not have a material effect thereon.*

The Proposed Merged Entity may have the following options and performance rights on issue following implementation of the Proposed Scheme:

Table 21

	Section reference	Unit	
Partly-paid shares	**1.1**	**'000s**	**9,949**
Existing ROC options / rights			
Executive Share Options	3.3	'000s	300
LTI Rights under the LTIP and EIP	3.3	'000s	19,423
Deferred STI Rights	3.3	'000s	2,274
Options to be issued in ROC			
Options	1.1	'000s	1,839
Performance rights	1.1	'000s	25,399
Total		**'000s**	**59,183**

Source: Horizon

5 Valuation approach

5.1 Summary

For the purpose of our opinion fair market value is defined as the amount at which the shares would be expected to change hands between a knowledgeable willing buyer and a knowledgeable willing seller, neither being under a compulsion to buy or sell. Special purchasers may be willing to pay higher prices to reduce or eliminate competition, to ensure a source of material supply or sales, or to achieve cost savings or other synergies arising on business combinations, which could only be enjoyed by the special purchaser. Our valuations have not been premised on the existence of a special purchaser.

Deloitte Corporate Finance has assessed the equity value of Horizon and the Proposed Merged Entity using a sum-of-the-parts approach, which requires the aggregation of the fair market value of the interests held in the various operating, development and exploration assets and corporate assets, before deducting net debt and adding or subtracting any surplus assets and liabilities.

It is common market practice to use the discounted cash flow method to value oil and gas assets due to their finite lives and the significant capital expenditure required in the development stage and preparatory phases of production.

We have used the discounted cash flow method to value the operating and development assets, which generates a value that is inclusive of a premium for control. We have cross-checked the values derived under the discounted cash flow method using an industry rule of thumb, namely a comparison of the multiple of USD per boe implied by our valuation with those achieved in recent trading and selected transactions in comparable companies. The value of the PNG assets has been cross-checked to the Osaka Gas Transaction and recent transactions in a nearby field.

Exploration assets have been valued by RISC, the technical expert engaged by Deloitte Corporate Finance to assist in the preparation of our independent expert's report. RISC has also provided us with its views on the various production, operating and capital expenditure assumptions adopted in the cash flow models prepared by Horizon and ROC management and, for certain assets, has advised us where it considers the assumptions should be adjusted.

In addition to cross-checking the values derived at the asset level, we have also compared the total equity value estimated for Horizon to that implied by trading in its shares prior to the announcement of the Proposed Scheme on 29 April 2014, after adjusting for a notional discount for minority interest.

We have taken the same approach to cross-checking the value of the Proposed Merged Entity, however we have compared the estimated equity value to the value of the Proposed Merged Entity based on trading in ROC's shares in the period after the announcement date. Trading in ROC's shares is likely to incorporate the market's view of the prospects of the Proposed Merged Entity to the extent that market participants expect the Proposed Scheme to proceed.

Surplus assets have been valued at fair market value, using either the discounted cash flow method (to estimate the likely cash flow arising from the asset or liability) or book value.

In summary, the following methodologies have been applied to value the assets of Horizon and the Proposed Merged Entity (which reflects the aggregation of the operations of Horizon and ROC):

Table 22

Asset	Type of Asset	Methodology
Shared assets		
Beibu Gulf (WZ 6-12 and WZ 12-8 West)	Operating	Discounted cash flow method
Beibu Gulf (WZ 12-8 East)	Exploration	Value estimated by technical expert
Horizon assets / liabilities		
Maari/Manaia (PMP 38160)	Operating / exploration	Discounted cash flow method
Stanley (PDL 10)	Development	Discounted cash flow method
Elevala-Ketu (PRL 21)	Development / exploration	Discounted cash flow method / value estimated by technical expert
Matariki, Whio, Te Whatu and Pukeko (PEP 51313)	Exploration	Value estimated by technical expert

Asset	Type of Asset	Methodology
PPLs 259, 372, 373 and 430 (PNG)	Exploration	Value estimated by technical expert
Osaka Gas Transaction proceeds	Surplus asset	Discounted cash flow method
ROC assets / liabilities		
D35/D21/J4 PSC	Operating / exploration	Discounted cash flow method / value estimated by technical expert
Zhao Dong (C&D and C4)	Operating	Discounted cash flow method
Cliff Head	Operating / exploration	Discounted cash flow method / value estimated by technical expert
Blane	Operating	Discounted cash flow method
Enoch	Operating	Discounted cash flow method
Zhao Dong, Zhanghai and Chenghai Blocks (Bohai Bay)	Exploration	Value estimated by technical expert
Block M07 (Myanmar)	Exploration	Value estimated by technical expert
Balai Cluster RSC	Surplus asset	Book value
Other assets		
Corporate costs	Corporate	Discounted cash flow method

Source: Deloitte Corporate Finance analysis

Refer to Appendix B for a detailed discussion on the various valuation methodologies which can be adopted in valuing corporate entities and businesses, but can be adapted to valuing assets, as appropriate.

5.2 Appointment and role of the technical expert

The management of Horizon and ROC prepared financial models to estimate the future cash flows for the underlying assets of the businesses. RISC has been engaged by Deloitte Corporate Finance to prepare a report providing a technical assessment of certain key assumptions underpinning the financial models.

In particular, RISC reviewed and/or provided input into the formulation of the following assumptions:

- reserves and resources estimates
- production profiles
- operating expenditure
- capital expenditure.

RISC was also engaged to provide an assessment of the value of the evaluation and exploration assets of Horizon and ROC.

RISC prepared its technical report having regard to:

- the Technical Assessment and Valuation of Mineral and Petroleum Assets and Securities for Independent Expert Reports 2005 Edition
- the guidelines and definitions of the Petroleum Resources Management System approved by the Board of the Society of Petroleum Engineers in 2007.

The scope of RISC's work was controlled by Deloitte Corporate Finance. A copy of RISC's report is provided in Appendix G.

6 Future cash flows of Horizon and ROC

6.1 Introduction

The interests in the operating and development assets held by Horizon and ROC have been valued using the discounted cash flow method, which estimates fair market value by discounting estimated future cash flows to their net present value. This section sets out the assumptions adopted to estimate the future cash flows of the operating and development assets.

6.2 The Models

Horizon and ROC management provided Deloitte Corporate Finance with financial models, which estimate the future cash flows from each of the operating and development assets in which Horizon (the Horizon Model) and ROC (the ROC Model) hold interests. The Horizon Model and the ROC Model are referred to collectively as the Models.

The Models contain projections of nominal, after-tax cash flows in USD, on a 100% and net interest basis. The Models were prepared based on:

- the latest reserve and resource statements, which have been assessed by RISC
- the asset development plans for the assets held by Horizon and ROC
- contractual arrangements in place.

We have made some adjustments to the cash flow projections in the Models where it was considered appropriate. These adjustments included, but were not limited to pricing, production volumes and inflation.

The analysis we have undertaken in respect of the Models included:

- working with RISC, to review and/or provide the technical assumptions underlying the Models (refer to Appendix G)
- limited analytical procedures regarding the mathematical accuracy of the Models (our work did not constitute an audit or review of the projections in accordance with the AUASB Standards)
- high level examination of the integrity of the Models, both from the perspective of the accuracy of information modelled and any omissions
- holding discussions with the management of Horizon and ROC concerning the preparation of the projections in the Models and their views regarding the assumptions on which the projections are based.

RISC have prepared a report providing a technical review of certain assumptions (reserves, resources, production volumes, operating and capital costs) supporting the future cash flows of the Models. RISC has held discussions with the management of Horizon and ROC and has reviewed data, reports and other information that is either publicly available or made available to RISC by Horizon and ROC management.

Our work did not constitute an audit or review of the projections in accordance with the AUASB Standards and accordingly we do not express any opinion as to the reliability of the projections or the reasonableness of the underlying assumptions. However, nothing has come to our attention as a result of our limited work that suggests that the assumptions on which the projections are based have not been prepared on a reasonable basis unless specified otherwise.

Since projections relate to the future, they may be affected by unforeseen events and they depend, in part, on the effectiveness of management's actions in implementing the plans on which the projections are based. Accordingly, actual results are likely to be different from those projected because events and circumstances frequently do not occur as expected, and those differences may be material.

The key assumptions supporting our valuations are described in the following sections.

6.3 Revenue

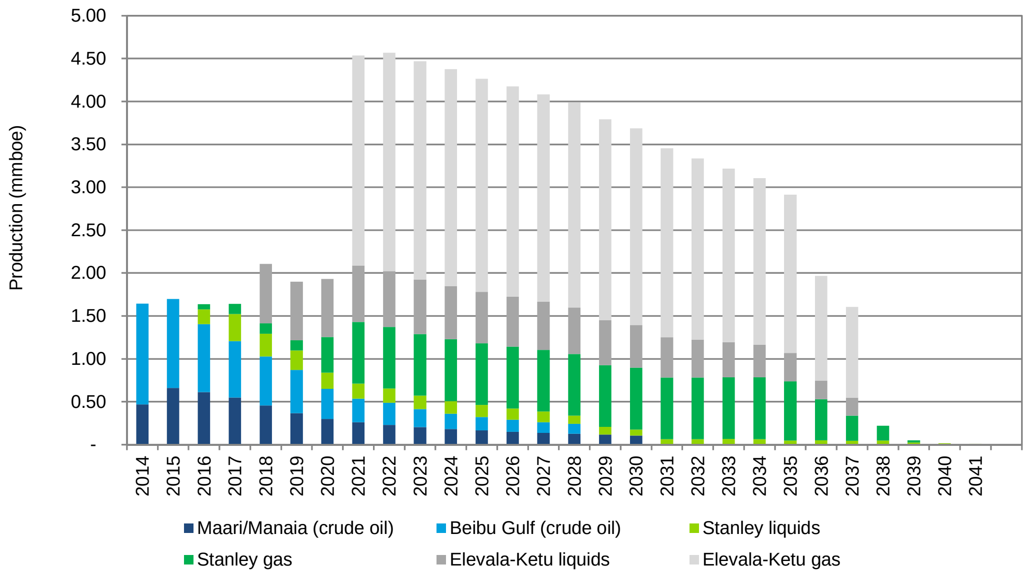
Revenue is a function of production and prices, which are discussed in the following sections.

6.3.1 Production assumptions

The figures below outline the projected production volumes from the Horizon and ROC assets for the period 1 April 2014 to 31 December 2041 (on a net interest basis).

Horizon production

Figure 7 – Horizon production (interest basis)



Source: Horizon Model; Deloitte Corporate Finance analysis

The valuation scenarios considered for the assets in which Horizon owns an interest are summarised as follows:

- **Maari/Manaia:** crude production based on current 2P reserves
- **Beibu Gulf:** crude oil production based on current 2P reserves
- **Stanley:** 13 mmboe of condensate volumes and 315 PJ of gas volumes extracted under a liquids stripping and gas export case (on a 100% basis)
- **Elevala-Ketu:** 50 mmboe of condensate volumes and 1,024 PJ of gas volumes extracted under a liquids stripping and gas export case (on a 100% basis).

  The Elevala-Ketu volumes presented above reflect Horizon management's estimate on the timing of production. However, we have modelled a one year delay to first gas production as discussed below.

RISC provided its view on whether or not production profiles are subject to specific risks. We have taken this into account in selecting our preferred production scenarios and the risk adjustments incorporated in our valuation analysis.

We note that production at the Maari/Manaia field may be lower than currently forecast if the field cannot extract incremental oil from water injection. The overall effect of choosing the slightly lower production profile is not material to our valuation of Horizon's interest in this asset. As a result we have assumed the 2P production profile prevails.

There are a number of commercialisation options for the gas of the PNG assets, including:

- **the gas of Stanley and Elevala-Ketu is aggregated with volumes in the Western Province forelands and processed by a near shore LNG facility (with a capacity of between 2 mtpa and 4 mtpa).**

  Under this scenario, the Stanley and Elevala-Ketu gas volumes will be aggregated with Western Province volumes from both wet and dry fields, together with volumes from offshore gas fields. The gross costs of the downstream infrastructure will be shared across the upstream participants to the extent they choose to participate in the downstream infrastructure

- **the gas is sold to the PNG LNG Project:** under this scenario, the two-train PNG LNG Project could add more trains, with the gas sourced from fields including the 2.5 tcf P'nyang field north of Stanley. If, as a consequence, a pipeline is built from P'nyang (in the highlands) to the forelands, Elevala-Ketu's proximity to infrastructure may allow it to participate in the PNG LNG Project
- **the gas is sold to a potential new LNG facility to be developed by Total SA, InterOil Corporation and Oil Search:** in March 2014, Total SA purchased a 40.1% interest in PRL 15 (the Elk-Antelope fields) from InterOil Corporation. The consideration includes a deferred component of USD 73 million payable on FID for an Elk-Antelope LNG project. This transaction followed Oil Search's acquisition earlier in the month of a 22.8% stake in the same field from Pacific LNG Operations Limited. Both InterOil Corporation and Total SA have expressed their intention to develop a second LNG facility in PNG which will further increase the demand for feed gas within PNG
- **some of the gas is sold to Ok Tedi and the Frieda River copper project:** Horizon management has been in discussions with Ok Tedi management for the mine to potentially take up to 3 PJ of gas per annum. The Frieda River project, which is one of the world's largest undeveloped copper gold deposits, could also be powered by gas fired power from the Stanley field if it is developed
- **the gas is sold to an LNG facility to be built in Daru:** under this scenario, an LNG facility is built to accommodate the majority of gas volumes from the Stanley and Elevala-Ketu fields.

We have assumed that the final scenario occurs and the gas of the Stanley and Elevala-Ketu fields is sold as export gas via an LNG facility from 2020, with early gas to be sold in much smaller volumes to domestic consumers from 2016. However many milestones need to be met, at significant cost and risk, for a gas to LNG export case for the two fields to become a reality.

Based on discussions with RISC on the various options available to sell the gas, we have assumed that a 1.5 mtpa mid-scale LNG facility will be developed in Daru.

RISC has estimated the gross capital cost of a mid-scale facility to be in the region of USD 2 billion, with annual operating costs of USD 130 million (all in present day USD). These costs would be charged on to the Stanley and Elevala-Ketu operations via an economic rent.

The economics of a mid-scale LNG facility also depend on the volumes of gas to be processed, with greater volumes creating economies of scale and a lower cost per unit of production from the two fields. Stanley and Elevala-Ketu gas volumes sold for conversion to LNG will be priced with reference to LNG prices, netted back for the necessary downstream infrastructure. An alternative for some of the Stanley gas is for it to be sold to domestic customers, which we have assumed commences in 2016.

Given the significance of the gas resources, an LNG project is required to process all of the gas resources of the Stanley and Elevala-Ketu fields. We have therefore selected a range of prices for the gas (refer to Section 6.3.2 below) that we consider may be achieved in the event an LNG facility is developed, however we consider that the price selected also covers other sales options for the gas.

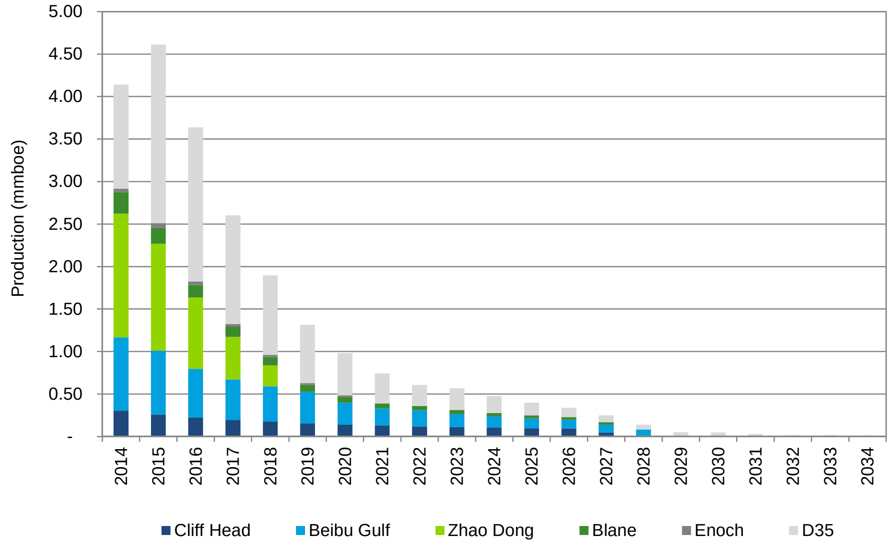
There is significant uncertainty associated with our base case scenario which assumes construction of an LNG facility in Daru. Without this occurring, most of the gas (Stanley and Elevala-Ketu) will not be sold in the manner we have assumed, with Stanley and Elevala-Ketu's value driven by projected condensate production, with comparatively minimal return from gas production. In addition, to the extent an LNG facility is constructed, RISC considers that gas production at the Stanley and Elevala-Ketu fields may be delayed. We have assumed that production is delayed by one year, which may result in additional capital expenditure in the region of USD 30 million, compared to Horizon management's assumptions on timing of production (i.e. first Elevala-Ketu gas in 2020).

Taking into account the overall risks inherent in our base LNG scenario assumed, we have applied a probability factor of 50% to 60% to the overall net present value ascribed to the interests in these assets.

The assumptions underpinning the production profiles for the Horizon assets have been reviewed by RISC, and are considered reasonable.

ROC production

Figure 8 – ROC production (interest basis)



Source: ROC Model; Deloitte Corporate Finance analysis

The valuation scenarios adopted for the assets in which ROC owns an interest are summarised as follows:

- **Cliff Head:** crude oil production based on current 2P reserves
- **Beibu Gulf:** crude oil production based on current 2P reserves
- **Zhao Dong:** crude oil production based on current 2P reserves that are expected to be recovered by 2018 (when the PSC ends)
- **Blane:** production based on current 2P reserves
- **Enoch:** production based on current 2P reserves
- **D35/D21/J4:** base scenario production is based on 2P reserves, however we have also considered additional production profiles, which consider additional production of additional 2C resources over three phases. RISC considers that these phases are subject to a number of risks and has recommended probability factors applicable to each incremental stage of 2C production. In summary, the first stage of production is assumed to be reasonable (based on 2P reserves), with probability factors of 70%, 25% and 25%, respectively, applicable to the incremental value generated by the three concurrent stages of production (relate to production of 2C resources). The application of these risk factors is driven by uncertainty in the scope and efficiency of the waterflood project to be undertaken in the second stage of production, and the additional uncertainty associated with the Enhanced Oil Recovery project proposed to be undertaken in stage 3.

The assumptions underpinning the production profiles for the ROC assets have been reviewed by RISC and are considered reasonable.

6.3.2 Pricing assumptions

This section set out the prices we have adopted for each source of revenue.

Oil pricing

The oil expected to be produced by the Horizon and ROC assets is priced with reference to crude oil prices. In considering an appropriate price to apply to the future sales of oil, we have had regard to the following:

- WTI and Brent crude oil price
- IRAC reported by the EIA
- NYMEX futures prices for WTI and Brent
- APPI Tapis crude oil prices

- other publicly available industry estimates and commentary, including but not limited to industry research and brokers estimates.

Based on our analysis, we have adopted crude oil pricing, as set out below:

- the NYMEX futures prices in the short to medium term, declining to a longer term oil price assumption
- a long term real oil price in the range of USD 90 per barrel to USD 95 per barrel in real 2014 terms. We have assumed a long term inflation rate of 2.0% in our pricing.

Our selected crude oil pricing assumptions (in 2014 real terms) are as follows:

Table 23[1]

USD per barrel	2014	2015	2016	2017	2018	Long term
Selected crude oil price (high)	105	100	98	97	96	95
Selected crude oil price (low)	105	100	97	95	92	90

Source: Deloitte Corporate Finance analysis
Note:
1. 2015 prices have been bridged down on a straight line basis to equal long term prices in 2019.

We have adopted the same oil prices for the condensate production of the Stanley and Elevala-Ketu fields.

Where appropriate, we have applied the following premiums/discounts to our selected oil price, representing historical differences in the quoted oil price and that achieved by Horizon/ROC:

Table 24

Asset	Premium / (discount) USD / bbl
Shared assets	
Beibu Gulf (WZ 6-12 and WZ 12-8 West)	(5.0)
Horizon assets	
Maari/Manaia (PMP 38160)	5.50
ROC assets	
D35/D21/J4 PSC	-
Zhao Dong (C&D and C4)	(5.0)
Cliff Head	(2.2)
Blane	-
Enoch	-

Source: Deloitte Corporate Finance analysis

Gas contracts

Prices have been modelled by reference to our selected oil price assumptions, as per the PSC. Due to the commercial sensitivity of pricing agreements, pricing information is generally not publicly available.

PNG gas sales

In assessing the cash flows for Elevala-Ketu we have considered various scenarios for the gas produced from Elevala-Ketu and the price that Horizon may be able to achieve.

Gas sales to an LNG facility

In determining a price that may be appropriate if Horizon's production is sold to an LNG facility in PNG, we have had regard to the following:

- our understanding of gas prices that are currently being achieved in the PNG gas market
- the potential for export LNG to impact gas pricing in the medium to long term, as increasing global demand for LNG is expected to increase the price of gas throughout the Asia Pacific market
- typical LNG pricing formula, as set out below:

LNG price = (A x JCC) + B

where:

- o Japanese Crude Cocktail (JCC) is the average cost, insurance and freight (CIF) price of a basket of crude oils sold to Japan in USD per bbl
- o A is typically between 0.12 to 0.165
- o B is typically between 0.5 to 1.0.

Based on this typical LNG price equation, our preferred slope assumption and our selected oil price assumptions, we have selected a long term LNG price of USD 14.00 per GJ to USD 15.00 per GJ.

However, the potential net-back price obtainable by Horizon (i.e. a price for the gas at the field) is uncertain and requires a number of additional assumptions. RISC has provided us with a range of estimates of the potential netback that may be appropriate for the gas export cases of the Stanley and Elevala-Ketu fields, which were developed under a range of volume scenarios and our preferred oil and LNG price assumptions.

We consider Horizon may be able to access some, but not all, of the gas pricing over and above cost of production that may be available to an upstream participant in an LNG production facility.

Gas sales to domestic customers

An alternative for some of the Stanley gas is for it to be sold to domestic customers. We have taken account of in-principle prices currently being considered by Horizon in selecting our preferred gas price assumptions.

Selected PNG gas prices

Having regard to the foregoing, we have adopted a real (in 2014 terms) long term ex-field gas price in the range of USD 7.50 per GJ and USD 8.50 per GJ to apply to gas production from the Stanley and Elevala-Ketu fields.

6.4 Operating costs

The Models include projections of operating costs, which are summarised as follows:

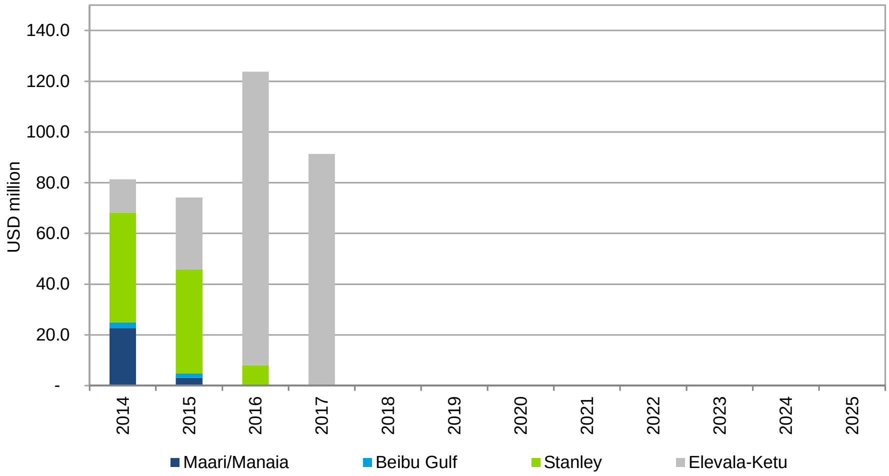
- operating fees
- workover costs
- tariffs for the use of platforms and processing and transportation
- variable costs including condensate transport, processing and storage costs
- project related overhead and administration costs including finance, commercial and technical support costs.

These operating costs have been reviewed by RISC which consider them to be reasonable. For a detailed overview of the operating costs, refer to Appendix G.

6.5 Capital costs

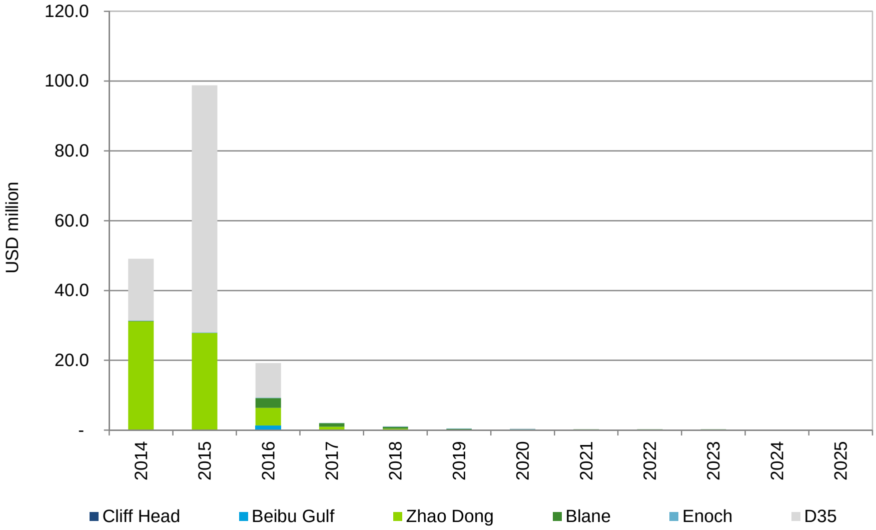
Capital costs have been projected based on a projected drilling schedule and other equipment required to extract and process the assumed oil and gas volumes. The following figures set out the projected capital costs (excluding abandonment costs) for Horizon and ROC.

Figure 9 – Horizon capital costs (interest basis)



Source: Horizon Model; Deloitte Corporate Finance analysis

Figure 10 – ROC capital costs (interest basis)



Source: ROC Model; Deloitte Corporate Finance analysis

Costs associated with abandonment are incurred for each of the assets as follows:

- at the end of the lives of the assets for those located in New Zealand, PNG, UK and Australia
- on an annual basis for the assets located in China and Malaysia, whereby the interest holders pay an annual contribution determined with reference to annual production volumes and the total cost of abandonment at the end of the life of the asset.

The assumptions underpinning the capital expenditure assumptions have been reviewed by RISC, which considers them to be reasonable. For a detailed overview of the capital expenditure costs, refer to Appendix G.

6.6 Corporate assumptions

The key corporate assumptions in the Models are summarised as follows:

- corporate tax is based on the rates applicable for each jurisdiction in which the assets are located, and is assumed to be paid over the life of each asset as and when incurred. ROC has unused tax losses not brought to account of approximately USD 216 million, which are included in the modelling of the Cliff Head asset (however tax losses remain at the end of the asset's life). Horizon has carried forward tax losses in Australia, however these are not projected to be used over the lives of the assets. Accordingly, we have ignored these tax losses in our valuation

- tax deductible depreciation in accordance with local taxation regimes, and based on the timing of commencement of production and the assumed life of the assets
- corporate tax payable based on local taxation regimes in New Zealand, China, Malaysia, Australia, UK and PNG
- government royalties and private royalties payable to third parties
- PRRT liability payable in relation to ROC's interest in the Cliff Head asset
- corporate overheads of approximately USD 10 million have been assumed for ROC until 2020 and USD 5 million until 2030, which is net of costs passed on to the Beibu Gulf assets for which it is the operator.

  Horizon currently incurs net corporate costs of approximately USD 7 million and is forecast to incur net costs of USD 5 million in 2014 and 2015. We have assumed Horizon will incur the same level of corporate costs as that incurred in 2014 and 2015 until the end of 2041. Corporate synergies on merger of the two companies have also been assumed and these are discussed in more detail in Section 7.4
- minimal material working capital movements.

6.7 Economic assumptions

The future cash flows in the Models are presented in nominal terms using Horizon and ROC's selected inflation rate assumptions. In selecting our inflation rate assumptions, we have considered forecasts prepared by economic analysts and other publicly available information, including broker consensus.

Based on our analysis, we have selected a flat inflation rate assumption of 2%.

6.8 Future cash flows attributable to Horizon and ROC

With respect to assets held by Horizon and ROC, future cash flows are based on the relevant interest in each asset's projected net operating cash flows after ongoing maintenance and construction capital costs, production sharing contract adjustments, PRRT, royalties and corporate tax payments.

For the interests held through a PSC (Beibu, Zhao Dong and D35/D21/J4), the cash flows modelled reflect cash flows associated with the PSC.

Under PSCs involving exploration activities, the international contractor must complete a minimum work commitment and bear all the costs during the exploration period. Post the minimum work commitment completed by Horizon and ROC, the nominated national company is assumed to take up its option to participate in the asset. Previously incurred development and operating costs incurred by Horizon and ROC are refunded by the nominated national company with production, via a specific cost recovery mechanism.

6.9 Discount rates

The discount rate (or WACC) used to equate the future cash flows to a present value reflects the risk adjusted rate of return demanded by a hypothetical investor. We have selected nominal post-tax discount rates to discount the future cash flows of the assets to their present value.

The discount rates have been chosen with reference to the stage of development of the assets, the geographic location of the assets (to capture sovereign risk) and any other asset specific risks that we consider are not already reflected in the future cash flows assumed for the asset.

The following discount rates have been selected to apply to the cash flows of the assets of Horizon and ROC:

Table 25

Asset	Stage of development	Country	Selected WACC Low	Selected WACC High
Shared assets				
Beibu Gulf	Operating	China	10.0%	11.0%
Horizon assets				
Maari/Manaia	Operating	New Zealand	9.0%	10.0%
Stanley	Development	PNG	12.0%	13.0%
Elevala-Ketu	Development		12.0%	13.0%
ROC assets				
D35/D21/J4 PSC	Operating	Malaysia	10.5%	11.5%
Zhao Dong (C&D and C4)	Operating	China	10.0%	11.0%
Cliff Head	Operating	Australia	9.0%	10.0%
Blane	Operating	UK	9.0%	10.0%
Enoch	Operating		9.0%	10.0%

Source: Deloitte Corporate Finance analysis

A detailed consideration of these matters is provided in Appendix D.

7 Valuation summary

7.1 Value of the operating and development assets

7.1.1 Summary

The range of values for the various oil producing assets have been estimated using the same crude oil price assumptions. The high end of the valuation range has been generated using high prices and low discount rates, and vice versa.

As the value of the Stanley and Elevala-Ketu fields are intrinsically linked (because their gas volumes are worth more in combination, than on a standalone basis), our preferred scenario to value these assets assumes the gas of the PNG assets is sold via a liquids stripping / gas export project to reflect the significant potential value that could be generated for these assets.

Given the uncertainty associated with the ability of Horizon and the other owners of the Stanley and Elevala-Ketu fields to monetise the significant potential of the gas resources, we have applied a probability factor in the range of 50% to 60% to the overall net present value ascribed to the interests in these assets. We have estimated the value of these assets with reference to our preferred discount rate range (of 12.0% to 13.0%) and the range of probability factors selected.

Our estimate of the fair market value of each of the operating and development assets is summarised in the table below.

Table 26

Asset	Horizon interest	ROC interest	Fair market value (USD million) Horizon interest Low	Horizon interest High	ROC interest Low	ROC interest High
Shared assets						
Beibu Gulf	26.95%	19.60%	223	232	162	169
Horizon assets						
Maari/Manaia	10.00%	-	164	175	-	-
Stanley & Elevala-Ketu	30.00% / 27.00%	-	180	260	-	-
ROC assets						
D35/D21/J4 PSC	-	30.00%	-	-	44	57
Zhao Dong	-	C&D – 24.50% C4 – 11.67%	-	-	89	91
Cliff Head	-	42.50%	-	-	22	26
Blane	-	12.50%	-	-	20	21
Enoch	-	12.00%	-	-	2	2
Total			**567**	**667**	**338**	**367**

Source: Deloitte Corporate Finance analysis

7.1.2 Cross-checks

We have used an industry rule of thumb to cross-check the value of the operating assets derived under our primary approach.

Given the significant gas resources of the Stanley and Elevala-Ketu fields, we have performed a separate cross-check to that used for the operating (primarily oil) producing assets, by comparing our valuation with the terms of the Osaka Gas Transaction and considering another recent transaction in a nearby field.

Operating assets

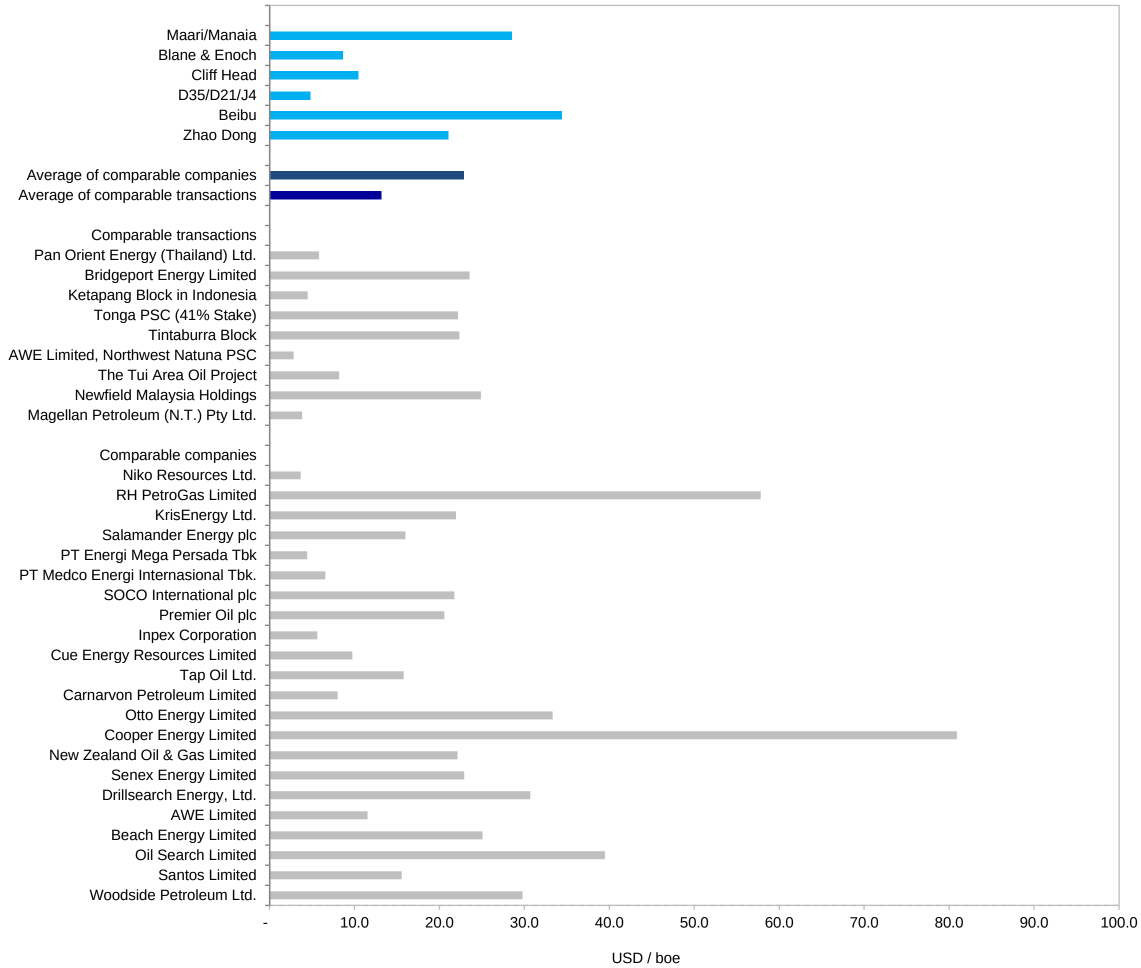
The rule of thumb cross-check, namely a comparison of the USD per boe implied by our valuation with those achieved in recent selected transactions in comparable companies, has emerged from market transactions as it can be calculated by analysts based on limited publicly available information.

This rule of thumb should be considered within the context of the following limitations:

- Australian disclosure standards for contingent resources have recently changed, which results in resource statements dated prior to 31 December 2013 being prepared on a different basis to those reported after that date
- it can be difficult to source accurate information on comparable transactions
- we have focused our search on comparable transaction and companies primarily focused on oil production and exploration in Asia. We have had difficulties in sourcing reported 2P reserves for Asia based transactions, in particular for PNG
- capital expenditure may be different to those of the comparable transactions and the difference could have a significant impact on value
- we have undertaken the calculation of the reserve multiples of the comparable companies and transactions based on 2P reserves, as the production volumes modelled in our analysis of the assets, primarily consist of 2P reserves (prospective and contingent resource evaluation has been undertaken by the technical expert, with the exception of the PNG assets and D35/D21/J4). Therefore the 2P reserve multiple calculation of the comparable companies and transactions does not make allowance for the relative proportion of prospective and contingent resources in place attributable to an asset, nor does it allow for different cost structures of the resources held by the subject company and the comparable companies
- the rule of thumb assumes the fields held by the subject company and those subject to the comparable transactions are at the same stage of development.

The 2P multiple for each of the assets implied by our valuation compared to those of comparable companies is shown in the figure below.

Figure 11



Source: Deloitte Corporate Finance analysis; Capital IQ; ASX announcements
Note:
1. Multiples calculated by dividing the value of the asset by the quantum of 2P reserves.

We make the following comments in respect of the above chart:

- the multiples implied by the comparable companies are based on share trading and do not reflect a control premium. We have added a control premium of 30% to the market capitalisations of the comparable companies in order to derive an indicative multiple on a control basis
- the implied 2P multiple observed for Cooper Energy Limited is considerably greater than those of the assets of Horizon and ROC. Cooper Energy Limited has significant contingent and prospective resources, which are not taken into account in the 2P reserve multiple (including the resources associated with the recent acquisition of the BMG asset)
- of the observed transactions, three hold PSCs in Asia, being the acquisition of Newfield Malaysia Holdings, the Northwest Natuna PSC in Indonesia and the acquisition in the Tonga PSC. Newfield Malaysia Holdings (operator of nine PSCs) and the Tonga PSC, encompass interests that are more developed than the Northwest Natuna PSC, which was 50% acquired by Santos and contains the undeveloped Ande Lumut oil field (FID to develop the field is expected in 2014). The consideration payable by Santos comprised USD 100 million in cash payable on completion of the sale and a USD 88 million cost recoverable capital expenditure carry
- the 2P reserves used as a basis for calculating the reserve multiple for the assets held through a PSC is based on Horizon/ROC's underlying interest in the asset, however the effective interest volume modelled may differ, due to the profit sharing mechanism underlying the PSC
- the 2P reserve multiple for Enoch, Blane and Cliff Head are lower than that of the other assets and towards the low end of the 2P reserve multiples observed for the comparable companies and transactions. Given the size of these fields, we do not consider this to be unreasonable
- the value calculated for D35/D21/J4 includes 2C prospective resources, which is not reflected in the calculated 2P reserve multiple.

We consider the 2P reserve multiples implied by our valuation of the assets to be reasonable.

Stanley and Elevala-Ketu

The possible valuation range for Stanley and Elevala-Ketu is wide as a result of the wide range of potential scenarios for the fields. Below, we present an analysis on the sensitivity of our combined valuation of Stanley and Elevala-Ketu (at the interest level) to the probability factor applied and delay scenarios.

Table 27

	Probability factor								
	20%	30%	40%	50%	60%	70%	80%	90%	100%
	Discount rate of 13%								
No delay	81	122	163	204	244	285	326	367	407
1 year delay	75	112	150	187	225	262	300	337	375
2 year delay	72	108	144	180	217	253	289	325	361
	Discount rate of 12%								
No delay	93	139	185	231	278	324	370	417	463
1 year delay	86	129	172	215	258	301	344	387	430
2 year delay	83	124	166	207	248	290	331	373	414

Source: Deloitte Corporate Finance analysis

There is uncertainty as to the likelihood of the gas export case, along with the timing of commencement of production, which is difficult to quantify with precision, however we consider a delay of one year is reasonable following discussions with RISC.

We have selected a value of USD 180 million to USD 260 million for the Stanley and Elevala-Ketu fields, which is based on our preferred discount rates, a delay of one year, and probability factors of 50% to 60% to reflect the overall likelihood of the project proceeding.

In order to cross-check this value, we have considered the most recent transaction in the assets, being the Osaka Gas Transaction, and recent transactions in a nearby comparable asset, to assess whether our valuation of the Stanley and Elevala-Ketu appears reasonable.

Osaka Gas Transaction

In May 2013, Horizon announced that it had entered into an agreement with Osaka Gas to sell a 40% interest in Horizon's interest in the PNG assets, including PDL 10 (Stanley) and PRL 21 (Elevala-Ketu). On completion of this transaction, Horizon will own a 30% interest and a 27% interest in PDL 10 and PRL 21, respectively (pre-PNG Government back-in) whilst Osaka Gas owns a 20% and 18% interest in PDL 10 and PRL 21, respectively.

Osaka Gas paid a deposit of approximately USD 20 million to Horizon in 2013 when entering into the agreement, and is due to pay the next instalment in mid-2014. In addition, it will pay its share of costs incurred to date in developing the assets. In total, the consideration to be paid by Osaka Gas for a 20% interest in the Stanley and Elevala-Ketu fields is estimated as the sum of the following:

- USD 20 million deposit paid in 2013
- USD 78 million (following receipt of the development licence from the PNG Government on 30 May 2014), reflecting the balance of the first payment and costs incurred to date. Of this amount, approximately USD 77 million was paid to Horizon on 12 June 2014, with a further USD 1 million (approximately) to be received in the short term
- USD 130 million on FID of an LNG facility
- production adjustments where condensate production exceeds a particular threshold, which are estimated at between USD 11 million and USD 14 million per annum (in 2014 real terms) from 2019 onwards (on an undiscounted basis).

We have valued the consideration in the range of approximately USD 170 million and USD 200 million using our preferred discount rates and a probability factor of 50% to 60%. This implies a value of USD 185 million to USD 205 million for the interests held in the Stanley and Elevala-Ketu fields by Horizon.[20]

The low end of our valuation range for the Stanley and Elevala-Ketu fields is consistent with that implied by the Osaka Gas Transaction, when compared on a like-for-like basis, although it is important to recognise that Osaka Gas is only forecast to have paid USD 98 million of the consideration by the time the Proposed Scheme is implemented. Osaka Gas has structured the transaction such that its consideration for the asset is staged.

It is not unreasonable to assume that Osaka Gas has not yet paid for the full upside of the assets associated with the gas resources in 2013, whereas our valuation does incorporate the value of gas production. In addition, the transaction took place one year ago and events may have occurred that have resulted in the value of the assets increasing, including drilling activities, Horizon undertaking discussions with potential domestic gas customers and the issue of a development licence for Stanley (in late May 2014).

Oil Search and Total SA / PRL 15 transactions

In March 2014, Oil Search and Total SA each acquired an interest in PRL 15, located in the Eastern Margin of the Papuan Basin. Key details of the transactions are provided as follows:

- on 13 March 2014, Oil Search Limited acquired a 22.8% stake in PRL 15 from Pacific LNG Operations Limited for USD 900 million with a contingent payment of USD 0.775 per mcf for any 2C contingent resources greater than 7 tcf. The estimated gross 2C contingent resources for PRL 15 range from 5.3 tcf (as estimated by Oil Search) to 7.0 tcf (as estimated by Gaffney Clyne). On this basis, the resource multiples for the transaction range from USD 3.8 per bbl to USD 4.5 per bbl. In an ASX announcement, Oil Search stated that the acquisition was in line with its overall strategy to aggregate resources to underpin LNG development in PNG. PRL 15 is in close proximity to Oil Search's existing portfolio, with the transaction funded by way of a placement of 149 million shares to the PNG Government
- on 25 March 2013, Total SA acquired a 40.1% stake in PRL 15 from InterOil Corporation for USD 624 million, with further contingent payments and discovery bonuses payable on certification of 2C contingent resources and based on the volumes discovered from exploration wells. Assuming the same range of resources, the resource multiples implied by this transaction range from USD 1.3 per boe to USD1.8 per boe respectively.

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[20] Calculated using the simple average of the two interests held by Horizon in PRL 4 and PRL 21, assuming PNG Government back-in occurs

Our valuation of the Stanley and Elevala-Ketu fields implies a multiple in the range of USD 2.7 per boe to USD 3.8 per boe of 2C contingent resources.[21]

The recent transactions in PRL 15 by Total SA and Oil Search provide support for our valuation, although the range implied by these transactions is very wide.

On balance, we consider these cross-checks support the value that we have selected for the PNG assets.

7.2 Value of the exploration assets

7.2.1 Summary

RISC provided an independent technical assessment of the exploration assets and estimates of their fair market value. RISC has valued the exploration assets with reference to either a risked discounted cash flow method, the application of a contingent resource multiple to reported resources or a cost-based approach.

Based on our analysis and discussions with RISC, we consider RISC's valuations to be appropriate for the purpose of our valuation of Horizon and the Proposed Merged Entity. Refer to Appendix G for RISC's technical expert's report.

Table 28[1,2,3]

			Fair market value (USD million)			
	Horizon	ROC	Horizon interest		ROC interest	
Asset	interest	interest	Low	High	Low	High
Shared assets						
Beibu Gulf	26.95%	19.60%	4	4	3	3
Horizon assets						
New Zealand	10.00%	-	8	8	-	-
PNG	Various	-	20	20	-	-
ROC assets						
Bohai Bay	-	100.0%	-	-	16	16
Malaysia	-	30.0%	-	-	11	11
Myanmar	-	59.4%	-	-	2	2
Australia	-	42.5%	-	-	0	0
Total			**32**	**32**	**31**	**31**

Source: RISC; Deloitte Corporate Finance analysis
Notes:
1. *The values ascribed to the exploration assets assumes that relevant farm-ins have taken place*
2. *We have adopted RISC's best estimate of values for both the high and low end of the valuation ranges*
3. *Total values subject to rounding.*

[21] Based on RISC's view of 2P plus 2C resources (314 mmboe) multiplied by Horizon's interest in the Stanley and Elevala-Ketu fields post PNG Government back-in

7.3 Valuation of Horizon

7.3.1 Summary

Our estimate of the fair market value of a share in Horizon, including the underlying components of our valuation, is summarised in the table below.

Table 29

	Section reference	Unit	Low	High
Enterprise value of operating assets	7.1	USD million	387	407
Enterprise value of development assets	7.1	USD million	180	260
Enterprise value of exploration assets	7.2	USD million	32	32
Corporate costs	6.6	USD million	(67)	(73)
Surplus assets	7.3	USD million	154	174
Enterprise value of Horizon (on a control basis)		**USD million**	**687**	**801**
Net debt	7.3	USD million	(180)	(180)
Equity value (on a control basis)		**USD million**	**507**	**621**
Number of shares in Horizon	7.3	'millions	1,317	1,317
Value of a share in Horizon (on a control basis)		**USD**	**0.38**	**0.47**

Source: Deloitte Corporate Finance analysis

7.3.2 Surplus assets

Horizon has the following assets that do not contribute to the forecast cash flows that we have modelled. For this reason they have been treated as surplus assets and have been valued separately.

Table 30

(USD million)	Low	High
Osaka Gas Transaction – 2014 payment	78	78
Osaka Gas Transaction – FID LNG	49	60
Osaka Gas Transaction – liquids adjustment	27	36
Total	**154**	**174**

Source: Deloitte Corporate Finance analysis

As the development licence for Stanley was issued by the PNG Government on 30 May 2014, Osaka Gas paid Horizon USD 77 million (which includes costs incurred to date since 2013 by Horizon) on 12 June 2014 and is expected to pay a further USD 1 million (approximately) in the near term.

In addition, under the terms of the Osaka Gas Transaction, Osaka Gas will pay Horizon:

- USD 130 million on FID of an LNG facility. Considering our valuation of the PNG assets is based on the scenario that the gas resources will be mainly sold via an LNG project (with some gas to be sold to domestic consumers), we have assumed FID takes place in 2016
- production adjustments where condensate volumes exceed agreed thresholds. Based on the projected production assumptions for the assets, Horizon is estimated to be entitled to annual post-tax payments of between approximately USD 11 million and USD 14 million (in 2014 real terms) from 2019 onwards.

In estimating the fair market value of the consideration to be received from Osaka Gas, we have discounted the future proceeds by the same discount rate, and have applied the same range of probability factors, selected to value the PNG assets under our preferred liquids stripping / gas export scenario.

7.3.3 Net debt

We assumed that Petsec would exercise its vested options (15 million options) before their expiry by the end of June 2014 (refer to Section 4.2).[23] The options have an exercise price of AUD 0.364 per share.

Horizon's net debt position as at 31 March 2014 is shown below.

Table 31

	(USD million)
Current interest bearing liabilities	10
Non-current interest bearing liabilities	109
Convertible bonds	89
Less: cash	(23)
Less: proceeds from Petsec exercising its options prior to 30 June 2014	(5)[1]
Net debt	**180**

Source: Deloitte Corporate Finance analysis
Note:
1. *Based on 15 million options multiplied by AUD 0.364 per share, converted into USD at the current exchange rate of 1 AUD: 0.94 USD.*

We have adopted a value for the Convertible Bonds that is equivalent to their current carrying value (USD 84 million) plus the Incentive Payment offered by Horizon for bondholders to take up the Early Redemption Offer (refer to Section 1.1).

7.3.4 Shares in Horizon

Horizon's capital structure is discussed in Section 2.3. We have adjusted the number of ordinary shares on issue to reflect the unexercised vested options held by Petsec, which we assumed would be exercised prior to their expiry in June 2014.[24]

We have ignored all other options and SARs in Horizon given they are yet to vest and the uncertainty associated with the number of shares that will be issued in Horizon on exercise of the SARs. We note that we have taken an equivalent approach to valuing the shares in the Proposed Merged Entity. We have undertaken an analysis to assess the dilution effect of the unvested options exercising to their fullest extent and the maximum number of shares arising from conversion of the SARs and have determined that the impact is immaterial on the overall value estimated for a share in Horizon.

Horizon's assumed number of shares is summarised in the table below.

Table 32

	Unit	
Number of shares in Horizon	'millions	1,302
Petsec options	'millions	15
Number of shares in Horizon (assuming Petsec converts)	'millions	**1,317**

Source: Deloitte Corporate Finance analysis

7.3.5 Cross-check: analysis of recent share trading

We have compared the value estimated for a share in Horizon to that implied by trading in its shares prior to the announcement of the Proposed Scheme on 29 April 2014, after adjusting for a notional discount for minority interest and converting the USD per share calculated value into AUD.

[23] The net debt position and the number of shares in Horizon assume 15 million options held by Petsec Energy Limited were exercised prior to their expiry on 30 June 2014. We understand the options were not exercised as at the date of this report, however we have not updated our valuation to reflect this as it does not have a material effect thereon

[24] Ibid.

The market can be expected to provide an objective assessment of the fair market value of a listed entity, where the market is well informed and liquid. Market prices incorporate the influence of all publicly known information relevant to the value of an entity's shares. We believe that the share price, prior to the announcement of the Proposed Scheme, represents an objective assessment of the fair market value of Horizon's shares for the following reasons:

- Horizon only has one shareholder with a holding greater than 20% and approximately 11% of shares has been traded over the three months prior to the announcement of the Proposed Scheme. This suggests trading in Horizon's shares is moderately liquid, when compared with trading in comparable companies over the same period
- Horizon is followed by a number of equities analysts and is included within the S&P/ASX200 Index, which has facilitated increasing investment scrutiny and liquidity.

Share prices from market trading do not reflect the market value for control of a company as they are for portfolio holdings. Australian studies indicate the premiums required to obtain control of companies range between 20% and 40% of the portfolio holding values. A minority interest discount is the inverse of a premium for control[25] and generally ranges between 15% and 30%.

The value of a share in Horizon (in AUD) on a minority interest basis based on our valuation on a control basis and a notional discount for minority interest is shown in the table below.

Table 33

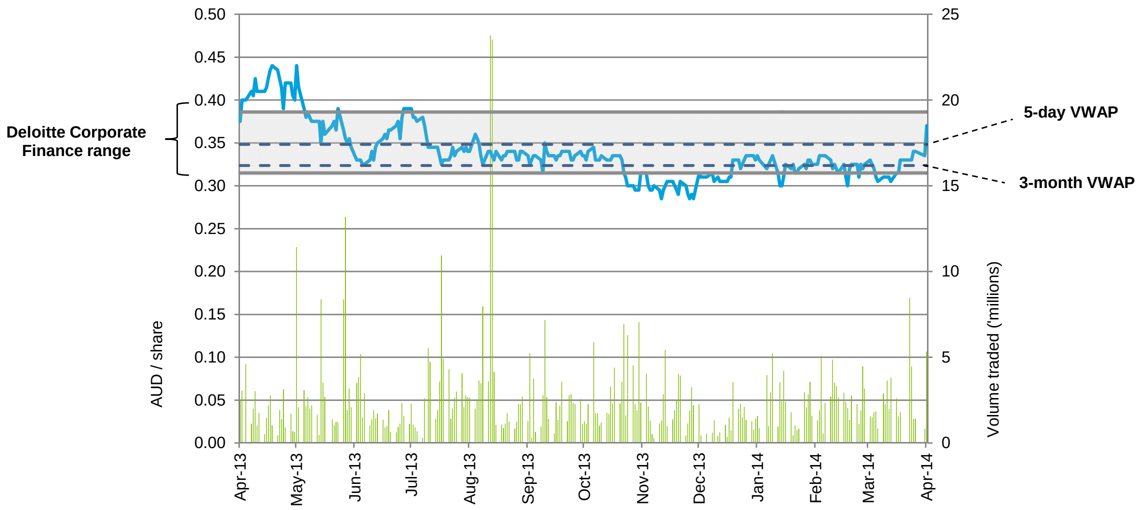
	Section reference	Unit	Low	High
Calculated value of a share in Horizon (on a control basis)	**7.3**	**USD / share**	**0.38**	**0.47**
Discount for minority interest[1]			23%	23%
Value of a share in Horizon (on a minority interest basis)		**USD / share**	**0.30**	**0.36**
Current AUD / USD exchange rate		%	0.94	0.94
Value of a share in Horizon (on a minority interest basis)		**AUD / share**	**0.31**	**0.39**

Source: Deloitte Corporate Finance analysis
Note:
1. Minority interest discount based on the inverse of a control premium of 30%.

[25] Minority interest discount = 1-{1/(1+control premium)}

The following figure shows various prices of Horizon shares over the twelve months prior to the announcement date of the Proposed Scheme on 29 April 2014 compared to the potential value of a share in Horizon on a minority interest basis implied by our valuation on a control basis.

Figure 12



Source: Capital IQ; Deloitte Corporate Finance analysis

The 5-day VWAP of a share in Horizon prior to announcement of the Proposed Scheme was AUD 0.35 per share compared to that implied by our valuation of AUD 0.31 per share to AUD 0.39 per share, with a midpoint of AUD 0.35.

Horizon's value is weighted towards the value ascribed to the PNG assets, which are in the development stage and subject to significant risks. Their potential value may not yet be fully understood or quantified by the market. Our wide valuation range for Horizon ultimately reflects the wide range of potential values for the PNG assets.

We consider the share price analysis is supportive of the value we have ascribed to a share in Horizon on a control basis.

7.4 Valuation of the Proposed Merged Entity

7.4.1 Summary

Our estimate of the fair market value of a share in the Proposed Merged Entity, including the underlying components of our valuation, is summarised in the table below.

Table 34

	Section reference	Unit	Low	High
Horizon				
Enterprise value of operating assets	7.1	USD million	387	407
Enterprise value of development assets	7.1	USD million	180	260
Enterprise value of exploration assets	7.2	USD million	32	32
ROC				
Enterprise value of operating assets	7.1	USD million	338	367
Enterprise value of exploration assets	7.2	USD million	31	31
Corporate costs				
Horizon	7.3	USD million	(67)	(73)
ROC	7.4	USD million	(67)	(70)
Add: corporate synergies	7.4	USD million	35	45
Surplus assets				
Horizon	7.3	USD million	154	174
ROC	7.4	USD million	52	52
Enterprise value of the Proposed Merged Entity (on a control basis)		**USD million**	**1,076**	**1,226**
Net debt	7.4	USD million	(101)	(101)
Equity value (on a control basis)		**USD million**	**976**	**1,125**
Number of shares in the Proposed Merged Entity (on an undiluted basis)	4.2	million	1,641	1,641
Value of a share in the Proposed Merged Entity (on a control basis)		**USD**	**0.59**	**0.69**

Source: Deloitte Corporate Finance analysis

7.4.2 Corporate costs

Refer to Section 6.6 for an overview of the corporate costs relating to Horizon and ROC.

We have assumed that Horizon and ROC, on merging, will be able to generate corporate cost synergies of approximately USD 3.5 million per annum until 2030 by:

- consolidating their corporate head offices into one location (therefore potentially halving rental costs and making proportionate savings on other overheads)
- carrying only one listing on the ASX, thereby reducing listing and similar fees
- sharing director and other management positions.

Synergies have been inflated at our selected inflation rate assumption and discounted to their net present value using a discount rate of 9.0% to 10.0%. Based on these assumptions, we have valued corporate cost synergies in the range of USD 35 million to USD 40 million.

7.4.3 Surplus assets

The Proposed Merged Entity has the following assets that do not contribute to the forecast cash flows that we have modelled.

Table 35

	Low (USD'000)	High (USD'000)
Horizon		
Osaka Gas Transaction – 2014 payment	78	78
Osaka Gas Transaction – FID LNG	49	60
Osaka Gas Transaction – Liquids adjustment	27	36
ROC		
Balai Cluster RSC	64	64
D35/D21/J4 PSC consideration payable	(12)	(12)
BMG consideration receivable	-	-
Total surplus assets	**206**	**226**

Source: Deloitte Corporate Finance analysis

Refer to Section 7.3 for a summary of Horizon's surplus assets.

We note the following in relation to ROC's surplus assets/liabilities:

- ROC holds a 48% interest in BC Petroleum, a joint venture company created to operate and manage the Balai Cluster RSC. ROC has advised that BC Petroleum is in the process of handing back all of the wells drilled to initiate early reimbursement of costs (expected within two years). The project to date has drilled five wells, installed four platforms and converted an early production vessel at a gross cost of approximately USD 310 million. Interest and some non-substantiated costs are non-recoverable.

  Based on discussion with ROC management, we are of the understanding a complete review of the costs for reimbursement is yet to be undertaken. Based on information provided by ROC management, we have discounted the book value as at 31 December 2013 by 5% to take into account unrecoverable costs

- ROC acquired a 50% interest in the D35/D21/J4 PSC as at 1 April 2014, with an effective ownership date of 1 January 2014. ROC has announced it intends to farm-out 40% of its interest (i.e. 20% of the PSC) to Dialog, effective 1 January 2014. The consideration for the farm-out will be at cost. The cash balance as at 31 March 2014 (presented below), does not take into account the consideration payable for ROC's net 30% interest (post 20% farm-out) and appropriate working capital adjustments between 1 January 2014 and 1 April 2014. Based on a consideration of USD 25 million for the 50% interest and working capital adjustment payable to ROC of approximately USD 5 million (estimated by ROC management), we have included a surplus liability of USD12 million

- ROC sold its interest in BMG effective 31 March 2014. Consideration for the sale was AUD 1.0 million upfront plus AUD 5.0 million contingent consideration (subject to first hydrocarbons from a commercial development at BMG). ROC management has provided an estimate of transaction costs relating to the sale, totalling AUD 1.0 million.

  ROC and the joint venture suspended BMG operations in 2010, because, at the time, a full field development was considered to be non-commercial. Whilst the joint venture has since undertaken a detailed development review designed to understand the most efficient routes to bring BMG gas and liquids to market, given the uncertainty surrounding this project, we consider it reasonable to ascribe a value of nil to the contingent consideration.

7.4.4 Net debt

The Proposed Merged Entity's net debt position as at 31 March 2014 is shown below.

Table 36

	(USD'000)
Horizon net debt	180
ROC net cash	(88)
Add: transaction costs	9
Net debt	**101**

Source: Deloitte Corporate Finance analysis

Refer to Section 7.3 for an overview of Horizon's net debt position.

As at 31 March 2014, ROC had a cash balance of USD 88 million and did not hold any debt. In addition, we have estimated Horizon and ROC's total transaction costs associated with the Proposed Scheme to be approximately USD 9 million, which we have added to the net debt position.

7.4.5 Analysis of recent share trading

The trading price of ROC shares subsequent to the Announcement Date should provide reasonable guidance on the trading price of shares in the Proposed Merged Entity, to the extent trading is relatively liquid. This is because the market is likely to have reflected the impact of the Proposed Scheme into ROC's share price immediately after it was informed of the terms of the Proposed Scheme, to the extent to which the Proposed Scheme is expected to proceed.

The potential value of a share in the Proposed Merged Entity (in AUD) on a minority interest basis, based on our valuation on a control basis and a notional discount for minority interest, is shown in the table below.

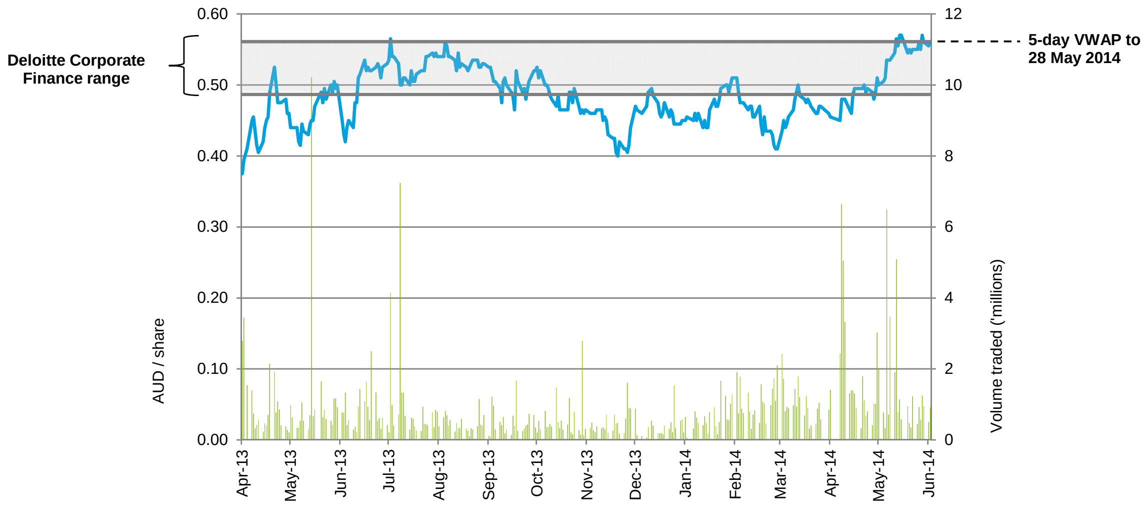
Table 37

	Section reference	Unit	Low	High
Calculated value of a share in the Proposed Merged Entity (on a control basis)	**7.4**	**USD / share**	**0.59**	**0.69**
Discount for minority interest[1]			23%	23%
Value of a share in the Proposed Merged Entity (on a minority interest basis)		**USD / share**	**0.46**	**0.53**
Current AUD / USD exchange rate		%	0.94	0.94
Value of a share in the Proposed Merged Entity (on a minority interest basis)		**AUD / share**	**0.49**	**0.56**

Source: Deloitte Corporate Finance analysis
Note:
1. *Minority interest discount based on the inverse of a control premium of 30%.*

The following figure shows various prices of ROC shares over the twelve months prior to the announcement date of the Proposed Scheme and the period that has passed since, compared to the potential value of a share in the Proposed Merged Entity implied by our valuation on a control basis.

Figure 13



Source: Capital IQ; Deloitte Corporate Finance analysis

The 5-day VWAP of a share in the Proposed Merged Entity to 24 June 2014 (before an unsolicited takeover offer for ROC was announced on 25 June 2014) was AUD 0.56 compared to that implied by our calculated valuation range of AUD 0.49 per share to AUD 0.56 per share, with a midpoint of AUD 0.52. Whilst share trading in ROC has been volatile over the course of the 12 months preceding announcement of the Proposed Scheme (with the share price falling to a low of AUD 0.38 per share and reaching a high of AUD 0.57 per share), the market has appeared to react favourably to the announcement of the Proposed Scheme, with the share price rising steadily from its closing price of AUD 0.46 per share on 23 April 2014. However, since announcement of the Proposed Scheme, a number of announcements unrelated to the Proposed Scheme have been released by both ROC and Horizon which may have influenced trading in ROC's shares in recent weeks, including ROC confirming that it had received an unsolicited takeover offer from a third party (on 25 June 2014). An independent expert's report prepared for ROC on the Proposed Scheme was also released on 16 June 2014.

Similar to our valuation of a share in Horizon, our wide valuation range for the Proposed Merged Entity reflects the wide range of possible values for the PNG assets.

Having regard to the above, we consider the share price analysis is supportive of the value we have ascribed to a share in the Proposed Merged Entity on a control basis.

Appendix A: Context to the Report

Individual circumstances

We have evaluated the Proposed Scheme for Horizon Shareholders as a whole and have not considered the effect of the Proposed Scheme on the particular circumstances of individual investors. Due to their particular circumstances, individual investors may place a different emphasis on various aspects of the Proposed Scheme from the one adopted in this report. Accordingly, individuals may reach different conclusions to ours on whether the Proposed Scheme is fair and reasonable and therefore in the best interests of Proposed Scheme. If in doubt investors should consult an independent adviser, who should have regard to their individual circumstances.

Limitations, qualifications, declarations and consents

The report has been prepared at the request of the Directors of Horizon and is to be included in the Scheme Booklet to be given to Horizon Shareholders for approval of the Proposed Scheme. Accordingly, it has been prepared only for the benefit of the Directors and those persons entitled to receive the Scheme Booklet in their assessment of the Proposed Scheme outlined in the report and should not be used for any other purpose. Neither Deloitte Corporate Finance, Deloitte Touche Tohmatsu, nor any member or employee thereof, undertakes responsibility to any person, other than the Horizon Shareholders and Horizon, in respect of this report, including any errors or omissions however caused. Further, recipients of this report should be aware that it has been prepared without taking account of their individual objectives, financial situation or needs. Accordingly, each recipient should consider these factors before acting on the Proposed Scheme. This engagement has been conducted in accordance with professional standard APES 225 Valuation Services issued by the Accounting Professional and Ethical Standards Board Limited.

The report represents solely the expression by Deloitte Corporate Finance of its opinion as to whether the Proposed Scheme is in the best interests of the Horizon Shareholders as a whole. Deloitte Corporate Finance consents to this report being included in the Scheme Booklet in the form and context in which it is to be included in the Scheme Booklet.

Statements and opinions contained in this report are given in good faith but, in the preparation of this report, Deloitte Corporate Finance has relied upon the completeness of the information provided by Horizon and ROC and each of their officers, employees, agents or advisors which Deloitte Corporate Finance believes, on reasonable grounds, to be reliable, complete and not misleading. Deloitte Corporate Finance does not imply, nor should it be construed, that it has carried out any form of audit or verification on the information and records supplied to us. Drafts of our report were issued to Horizon management, and certain extracts of our draft report were issued to ROC management, for confirmation of factual accuracy.

Subsequent to the issue of a full draft report to Horizon (including valuation outcomes and our opinion), a minor error was identified in the valuation undertaken by RISC in relation to the Bohai Bay exploration assets. We updated our valuation analysis to reflect the correct value (which was updated from USD 13 million to USD 16 million), which resulted in a minor change to the valuation range for a share in the Proposed Merged Entity. This change did not change our conclusion.

In recognition that Deloitte Corporate Finance may rely on information provided by Horizon, ROC and its officers, employees, agents or advisors, Horizon has agreed that it will not make any claim against Deloitte Corporate Finance to recover any loss or damage which Horizon may suffer as a result of that reliance and that it will indemnify Deloitte Corporate Finance against any liability that arises out of either Deloitte Corporate Finance's reliance on the information provided by Horizon, ROC and their officers, employees, agents or advisors or the failure by Horizon and / or ROC and their officers, employees, agents or advisors to provide Deloitte Corporate Finance with any material information relating to the Proposed Scheme.

Deloitte Corporate Finance also relies on the technical expert's report prepared by RISC. Deloitte Corporate Finance has received consent from RISC for reliance in the preparation of this report.

To the extent that this report refers to prospective financial information we have considered the prospective financial information and the basis of the underlying assumptions. The procedures involved in Deloitte Corporate Finance's consideration of this information consisted of enquiries of Horizon and ROC personnel and analytical procedures applied to the financial data, and the engagement of a technical expert to assist in evaluating certain key assumptions underpinning the financial projections. These procedures and enquiries did not include verification work nor constitute an audit or a review engagement in accordance with standards issued by the Auditing and Assurance Standards Board (AUASB) or equivalent body and therefore the information used in undertaking our work may not be entirely reliable.

Based on these procedures and enquiries, Deloitte Corporate Finance considers that there are reasonable grounds to believe that the prospective financial information for Horizon and ROC included in this report has been prepared on a reasonable basis in accordance with ASIC Regulatory Guide 111. In relation to the prospective financial information, actual results may be different from the prospective financial information of Horizon and ROC referred to in this report since anticipated events frequently do not occur as expected and the variation may be material. The achievement of the prospective financial information is dependent on the outcome of the assumptions. Accordingly, we express no opinion as to whether the prospective financial information will be achieved.

Deloitte Corporate Finance holds the appropriate Australian Financial Services licence to issue this report and is owned by the Australian Partnership Deloitte Touche Tohmatsu. The employees of Deloitte Corporate Finance principally involved in the preparation of this report were: Stephen Reid, Director, M App. Fin. Inv., B.Ec, F Fin, CA; Robin Polson, Director, B.Com, Grad. Dip. App. Fin. Inv; Alexandra White, Associate Director, BCom, CA; Odette Linnett, Associate Director, M. App. Fin, B.Com; Nick White, Analyst, BCom; and Alex Bartzis, Analyst, BBus. Stephen and Robin, Directors of Deloitte Corporate Finance, have many years of experience in the provision of corporate financial advice, including specific advice on valuations, mergers and acquisitions, as well as the preparation of expert reports.

Consent to being named in disclosure document

Deloitte Corporate Finance Pty Limited (ACN 003 833 127) of 550 Bourke Street, Melbourne, VIC, 3000 acknowledges that:

- Horizon proposes to issue the Scheme Booklet in respect of the Proposed Scheme
- the Scheme Booklet will be issued in hard copy and be available in electronic format
- it has previously received a copy of the draft Scheme Booklet for review
- it is named in the Scheme Booklet as the 'independent expert' and its independent expert's report is included in the Scheme Booklet.

On the basis that the Scheme Booklet is consistent in all material respects with the draft Scheme Booklet received, Deloitte Corporate Finance Pty Limited consents to it being named in the Scheme Booklet in the form and context in which it is so named, to the inclusion of its independent expert's report in the Scheme Booklet and to all references to its independent expert's report in the form and context in which they are included, whether the Scheme Booklet is issued in hard copy or electronic format or both.

Deloitte Corporate Finance has not authorised or caused the issue of the Scheme Booklet and takes no responsibility for any part of the Scheme Booklet, other than any references to its name and the independent expert's report as included therein.

Sources of information

In preparing this report we have had access to the following principal sources of information:

- draft Scheme Booklet and Merger Implementation Deed
- annual reports for Horizon and ROC, and comparable companies
- material contracts between Horizon and ROC and third parties, financial models prepared by management of Horizon and ROC, technical reports for each asset, and other internal management information
- company websites for Horizon, ROC and comparable companies
- publicly available information on comparable companies and market transactions published by ASIC, Capital IQ and Mergermarket
- other publicly available information, media releases and brokers reports on Horizon, ROC, comparable companies and the oil and gas industry.

In addition, we have had discussions and correspondence with certain directors and executives, including Michael Lyon, Corporate Counsel, Horizon; Richard Beament, Manager – Finance & Commercial, Horizon; and

Lorne Krafchik, Group Financial Controller, ROC; in relation to the above information and to current operations and prospects.

Appendix B: Valuation methodologies

To estimate the fair market value of the shares in Horizon and the Proposed Merged Entity, we have considered common market practice and the valuation methodologies recommended by ASIC Regulatory Guide 111, which provides guidance in respect of the content of independent expert's reports. These are discussed below.

Market based methods

Market based methods estimate a company's fair market value by considering the market price of transactions in its securities or the market value of comparable companies. Market based methods include:

- capitalisation of maintainable earnings
- analysis of a company's recent security trading history
- industry specific methods.

The capitalisation of maintainable earnings method estimates fair market value based on the company's future maintainable earnings and an appropriate earnings multiple. An appropriate earnings multiple is derived from market transactions involving comparable companies. The capitalisation of maintainable earnings method is appropriate where the company's earnings are relatively stable.

The most recent security trading history provides evidence of the fair market value of the securities in a company where they are publicly traded in an informed and liquid market.

Industry specific methods estimate market value using rules of thumb for a particular industry. Generally rules of thumb provide less persuasive evidence of the market value of a company than other valuation methods because they may not account for company specific factors.

Discounted cash flow methods

Discounted cash flow methods estimate market value by discounting a company's future cash flows to a net present value. These methods are appropriate where a projection of future cash flows can be made with a reasonable degree of confidence. Discounted cash flow methods are commonly used to value early stage companies or projects with a finite life.

Asset based methods

Asset based methods estimate the market value of a company's securities based on the realisable value of its identifiable net assets. Asset based methods include:

- orderly realisation of assets method
- liquidation of assets method
- net assets on a going concern basis.

The orderly realisation of assets method estimates fair market value by determining the amount that would be distributed to securityholders, after payment of all liabilities including realisation costs and taxation charges that arise, assuming the company is wound up in an orderly manner.

The liquidation method is similar to the orderly realisation of assets method except the liquidation method assumes the assets are sold in a shorter time frame. Since wind up or liquidation of the company may not be contemplated, these methods in their strictest form may not necessarily be appropriate. The net assets on a going concern basis method estimates the market values of the net assets of a company but does not take account of realisation costs.

These asset based methods ignore the possibility that the company's value could exceed the realisable value of its assets as they ignore the value of intangible assets such as customer lists, management, supply arrangements and goodwill. Asset based methods are appropriate when companies are not profitable, a significant proportion of a company's assets are liquid, or for asset holding companies

Appendix C: Oil and gas industry

Introduction

The oil and gas industry consists of two principal segments. The upstream segment explores for, produces and processes crude oil, natural gas liquids and natural gas. The downstream segment refines these outputs into fuels, lubricants and petrochemical products. Upstream oil and gas companies are often referred to as exploration and production companies.

The principal activities of Horizon and ROC consist of exploration, development and production of oil and gas. These activities fall within the upstream segment of the oil and gas industry. The key assets of Horizon and ROC are located throughout China, PNG, Malaysia, Myanmar, Australia, New Zealand and the UK.

Oil

Crude oil market

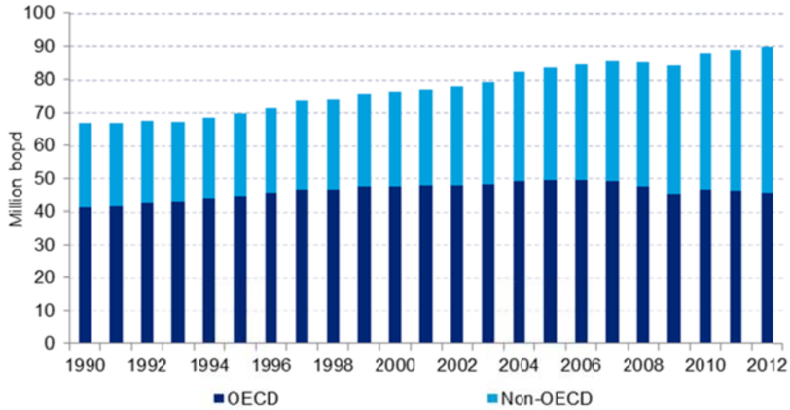
The quality of crude oil produced from a reservoir is primarily determined by its hydrocarbon content, density and sulphur content. While this quality varies from field to field, the refining industry has adapted its input capability sufficiently to deal with a range of qualities. The diversity of this input capability combined with the comparatively low transportation cost for crude oil has resulted in the development of substantial inter-continental trade in crude oil. Consequently the price for crude oil is a function of worldwide demand and supply.

Global crude oil demand

The demand for crude oil is dependent on the demand for goods and services that require oil-related products as inputs. Transportation, in particular road and air transportation, is the principal source of demand for oil constituting over 90%[26] of petroleum demand. Accordingly, the most important products made from crude oil are petrol and diesel. Other applications of oil derived products include the operation of stationary industrial equipment, including electricity generators, heating and road building.

Annual global demand for crude oil from 1990 to 2012 (in million bopd) split between supply from OECD countries and non-OECD countries is summarised in the following figure.

Figure 14



Source: BP Statistical Review of World Energy June 2013

The demand for petroleum products and therefore crude oil is linked to overall levels of global economic activity. IBISWorld cites regression analysis studies undertaken which indicate that the level of real gross domestic product explains just under 90% of the demand for petrol and approximately 98% of the demand for automotive distillate.

[26] IBISWorld

The weak economy of the early 1990s resulted in stagnant growth in demand for oil. The revival of economic growth in the member countries of the OECD and the rapid industrialisation of Asia since the mid-1990s has led to an increase in global demand for crude oil. However, demand for global crude oil recently decreased, primarily due to effects of the global financial crisis. In 2012, global oil demand increased by 1.0%, reversing the drop in demand over 2008 and 2009 which followed the global financial crisis.

Analysis prepared by the EIU indicates that oil consumption growth is expected to increase to 1.5% for 2014-15 based on forecasts that the downward-trending Japanese and Eurozone consumption in the prior years will be reversed. However, consumption growth is not expected to reach the highs of the last decade as a result of increasing efforts to reduce energy consumptions (both in the OECD and in some parts of the non-OECD), as well as some substitution with other, cheaper alternative fuel sources.

Crude oil supply

The world's crude oil supply system can be viewed as having two suppliers: the primarily state-owned producers located in countries which are members of the OPEC and the mainly privately-owned producers located in non-OPEC countries. OPEC is an inter-governmental association established to represent the interests of the crude oil exporting countries.

In 2012, OPEC held approximately 1,212 billion barrels of proven oil reserves, representing 73%[27] of world crude oil reserves. However, OPEC production accounted for only 41% of crude oil production in 2012.

The reason for the disparity between OPEC's percentage of reserves and production is its role in managing crude oil production. As part of its mandate, OPEC sets a production quota for each of the member countries[28]. History has shown that certain members of OPEC comply with the quota system and others do not, although in recent years there has been a high level of quota compliance among member countries.

The role of OPEC influences the crude oil market in a number of ways. Firstly, OPEC's supply management supports crude oil prices in the medium term. Secondly, in the short term, crude oil prices can be volatile as OPEC's supply remains relatively constant despite short term changes in demand. Thirdly, the major oil companies, which own most of the world's transportation, refining and marketing systems, do not have an equity interest in OPEC originated crude oil. Accordingly, integrated companies seek to add value to their own oil in the downstream segment before calling on OPEC production. History has shown that as the demand on OPEC crude increases to near OPEC's capacity to supply, prices tend to rise.

Crude oil pricing

There are over 150 different types of internationally traded crude oil (known as markers), which vary in terms of characteristics, quality and market penetration. Crude oil is generally priced relative to a number of key benchmarks or markers. The main criteria for marker crude oil is for it to be sold in sufficient volumes to provide liquidity (i.e. many buyers and sellers) in the physical market as well as having similar physical qualities to alternative crudes.

WTI

WTI crude oil is of very high quality, is excellent for refining and is generally described as a light, sweet crude oil. This combination of characteristics, together with its location, makes it an ideal crude oil to be refined in the US, the largest gasoline-consuming country in the world. Although the production of WTI crude oil is on the decline, it is still the major benchmark for crude oil in the US.

WTI is deeply traded on NYMEX and is generally priced at a premium of approximately USD 2 per barrel to the OPEC Basket price and approximately USD 1 per barrel to the Brent price, although on a daily basis the pricing relationships between these indices can vary greatly.

APPI Tapis

In Asia, the pricing mechanism is based on an independent panel approach where producers, refiners and traders are asked for information on actual trades and where there have been none, their best estimate. Any estimates that are significantly high or low are discarded and the quoted price is then an average of views on the market

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[27] BP Statistical Review of World Energy, June 2013

[28] The 12 member countries in OPEC are Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates and Venezuela.

price. The trade in APPI Tapis is limited to approximately six months in the future, which allows for a meaningful comparison to be made when making decisions to buy a APPI Tapis, Brent or Oman/Dubai linked crude, but prevents its use as a long term risk management tool.

IRAC

IRAC is the volume weighted average price of all crude oils imported into the US over a specified period. The US imports more types of crude oil than any other country and consequently, it may represent the average world oil price among all published crude oil prices. The IRAC is generally similar to the OPEC Basket Price and is typically traded at a discount of approximately USD 2 per barrel to the WTI spot price and approximately USD 1 per barrel to the Brent price.

The IRAC is used by the EIA as the world oil price in all of its projection publications, including the Short-Term Energy Outlook, released monthly, as well as the Annual Energy Outlook and International Energy Outlook, both of which are released annually and provide an annual projection looking out approximately 20 years into the future.

NYMEX futures

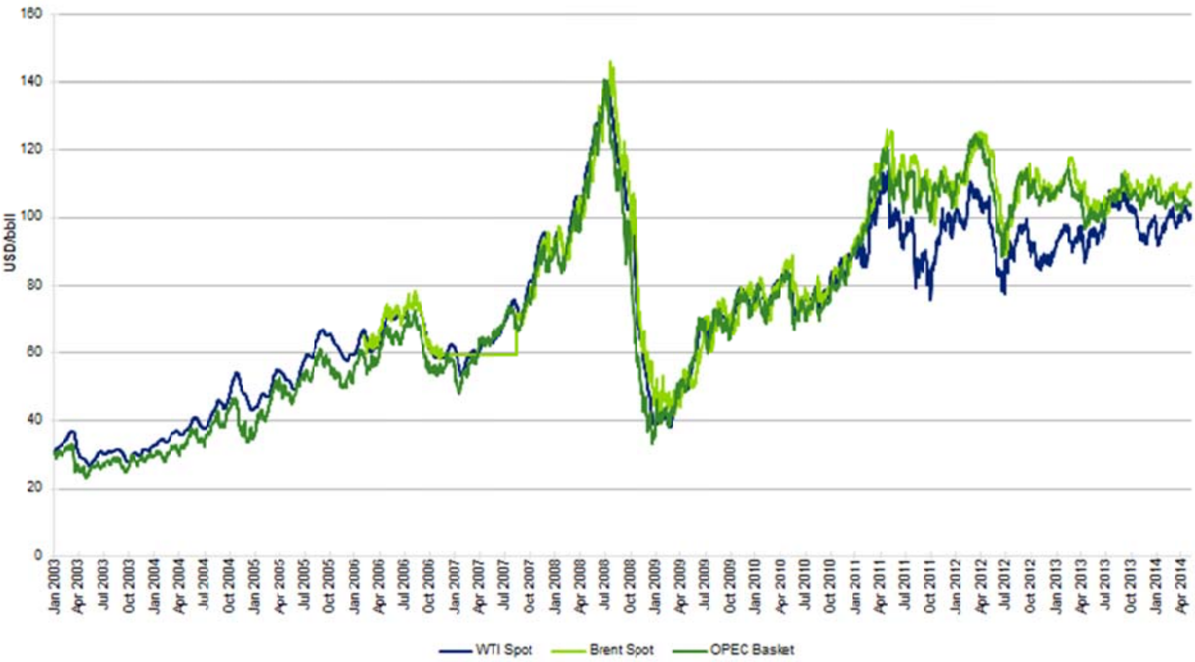
The NYMEX futures price for crude oil represents (on a per barrel basis) the market determined value of a futures contract to either buy or sell 1,000 barrels of WTI at a specified time. The NYMEX market provides important price information to global buyers and sellers of crude oil, making WTI the benchmark for many different crude oils, especially in the US.

Generally, these benchmarks move together though, on occasion, demand differentials for various types of crude create a pricing disparity.

Historical crude oil price analysis

The following figure shows the historical actual WTI , Brent and the OPEC Basket crude oil prices over the last decade.

Figure 15[1]



Source: Capital IQ
Note:
1. *Brent data prior to February 2006 is not available.*

From January 2004, the WTI crude oil price increased dramatically reaching USD 145 per barrel in July 2008. The increase in oil prices during this period can be attributed to a number of factors including:

- unprecedented demand growth from emerging nations such as China and India to support their domestic economic growth

- exploration and production companies not pursuing new projects during periods of relatively low oil prices up to around 2004, thereby limiting the supply of additional oil
- declining production from existing fields
- the role of OPEC in restricting oil production with production quotas for each member state
- global political factors surrounding supply and demand of oil
- growth in the economies of countries such as Japan and Taiwan which do not have their own energy supplies and are therefore dependent on the rest of the world for the supply of energy
- speculative activities by traders in global oil markets.

The WTI crude oil prices experienced a rapid and significant decrease when the GFC commenced in September 2008, reaching a five year low of USD 31 per barrel in December 2008. WTI prices have recovered to current prices of approximately USD 80 to USD 100 per barrel.

In our view, oil prices are likely to remain high relative to long term historical averages due to the following:

- fiscal breakeven oil prices as measured by the International Monetary Fund have increased markedly for most oil exporters in the Middle East since 2009
- the long term WTI crude oil price forecast in April 2014 by analysts in the range of USD 80 per barrel and USD 104 per barrel with an average of US 91 per barrel
- China, Saudi Arabia and India together had the largest growth in crude consumption among non-OECD countries for the last decade, with economists believing that the weakness in commodity prices since early 2013 can be attributed to concerns about the economic slowdown of China
- hydroelectric and renewable energy have competed strongly against carbon based fuel sources with renewables in power generation growing by 15% in FY2012[29].

Production and exploration companies will benefit from high oil prices, particularly those with existing infrastructure. High oil prices also provide owners of technically challenging, high cost and unconventional resources with an opportunity to extract oil at a profit.

Gas

Natural gas is a colourless and odourless fossil fuel found in reservoirs within the earth's crust. Natural gas is predominantly composed of methane (referred to as 'dry' gas if almost pure methane), however, other gases, including ethane, propane and butane may also be found (referred to as 'wet' gas when these hydrocarbons are present).

Natural gas is a much cleaner fossil fuel than oil and coal and produces less greenhouse gas per unit of energy released. For an equivalent amount of heat, natural gas produces about 45% less carbon dioxide than burning black coal.

Natural gas is an important energy source due to its abundance and the fact that it offers a number of environmental benefits over other energy sources.

International natural gas market

The natural gas industry is increasingly becoming a global industry with international trade of natural gas and LNG increasing to meet rising global demand. Analysis by the IEA indicated that while demand is increasing, albeit at a slower rate than coal, countries are increasing their dependence on inter-regional trade. Increases in demand is a result of the growing demand for energy out of China and India as non-OECD countries continue to be the driving force behind gas demand.

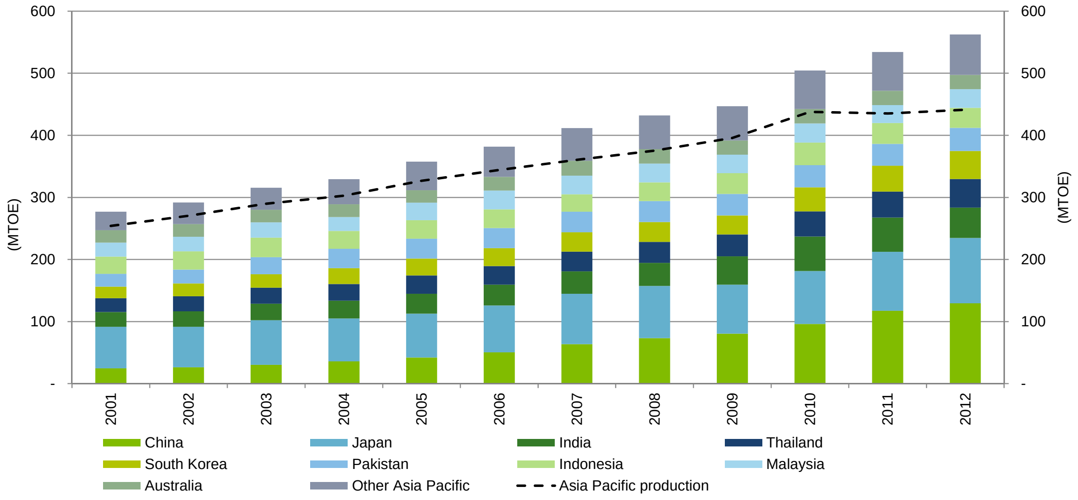
Asia Pacifc natural gas market

The Asia Pacific natural gas market is expected to become the second largest gas market by 2015, with 790 bcm of natural gas demand[30]. China, Japan, India Thailand and South Korea are the largest consumers accounting for

[29] BP Energy Statistics 2013
[30] IEA – Developing a natural gas hub in Asia

approximately 66% of total demand in the Asia Pacific market. The figure below sets out historical demand (by country) and production throughout Asia Pacific.

Figure 3



Source: BP Energy Statistics 2013

Increased demand from import dependant countries, such as Japan and South Korea, has resulted in the growth of the LNG export market for countries such as Indonesia and Malaysia, who are responsible for almost 30% of Asia Pacific production[31]. The demand for natural gas in the Asia Pacific region is expected to grow around 3% per annum, in line with global demand trends, to reach 875 bcm in 2017[32].

PNG has emerged as a developing gas market in the Asian region, experiencing strong growth and an increase in development activities. Recent gas/condensate discoveries in PNG have resulted in an increase in development from international LNG companies. The construction of major gas production and processing facilities, such as the USD 19 billion PNG LNG project, are expected to provide a long term supply of LNG to countries throughout the Asian region. PNG is expected to become a major LNG exporter to support the growing demand within the Asia Pacific gas market.

Long-term contracts have historically been the predominant means of trading natural gas in the Asia Pacific region, where the price of gas has been indexed to that of oil. However due to growth in demand and increased competition amongst suppliers, the use of short term contracts has become more prevalent, as they provide greater pricing flexibility for the current market conditions.

[31] IEA – Developing a natural gas hub in Asia
[32] IEA – Developing a natural gas hub in Asia

Appendix D: Discount rate

The discount rate used to equate the future cash flows to their present value reflects the risk adjusted rate of return demanded by a hypothetical investor for the asset or business being valued.

Selecting an appropriate discount rate is a matter of judgement having regard to relevant available market pricing data and the risks and circumstances specific to the asset or business being valued.

Whilst the discount rate is in practice normally estimated based on a fundamental ground up analysis using one of the available models for estimating the cost of capital (such as the Capital Asset Pricing Model (CAPM)), market participants often use less precise methods for determining the cost of capital such as hurdle rates or target internal rates of return and often do not distinguish between investment type or region or vary over economic cycles.

Since our definition of fair market value is premised on the estimated value that a knowledgeable willing buyer would attribute to the asset or business, our selection of an appropriate discount rate needs to consider that buyers incorporate other alternatives to the typical CAPM approach in estimating the cost of capital.

For ungeared cash flows, discount rates are determined based on the cost of an entity's debt and equity weighted by the proportion of debt and equity used. This is commonly referred to as the weighted average cost of capital (WACC).

The WACC can be derived using the following formula:

$$\boxed{WACC = \left(\frac{E}{V} * K_e \right) + \left(\frac{D}{V} * K_d (1 - t_c) \right)}$$

The components of the formula are:

K_e = cost of equity capital

K_d = cost of debt

t_c = corporate tax rate

E/V = proportion of enterprise funded by equity

D/V = proportion of enterprise funded by debt

The adjustment of K_d by (1- t_c) reflects the tax deductibility of interest payments on debt funding. The corporate tax rate has been assumed to be 30%, in line with the Australian corporate tax rate.

Given the international commodity nature of the outputs, a discount rate has been derived based on USD variables, in particular the risk free rate and the equity risk premium. The other discount rate variables, such as the beta and capital structure, are derived from an analysis of comparable companies. The tax rate is based on the applicable tax rate for country in which each asset is located.

Cost of equity capital (K_e)

The cost of equity, K_e, is the rate of return that investors require to make an equity investment in a firm.

We have used the CAPM to estimate the K_e for each of the assets in which Horizon and the Proposed Merged Entity own an interest. CAPM calculates the minimum rate of return that the company must earn on the equity-financed portion of its capital to leave the market price of its shares unchanged. The CAPM is the most widely accepted and used methodology for determining the cost of equity capital.

The cost of equity capital under CAPM is determined using the following formula:

$$\boxed{K_e = R_f + \beta(R_m - R_f) + a}$$

The components of the formula are:

K_e = required return on equity

R_f = the risk free rate of return

R_m = the expected return on the market portfolio

β = beta, the systematic risk of a stock

α = specific company (or asset) risk premium

Certain of the assets are located in countries that subject them to greater operational risks than if they were located in a developed country. This additional risk is often referred to as a country risk premium (CRP).

We have adopted CRPs and other asset risk premiums in order to reflect this increased operational risk as follows:

$$\boxed{K_e = R_f + CRP + \beta(R_m - R_f) + \alpha}$$

Each of the components in the above equation is discussed below.

Risk free rate (R_f)

The risk free rate compensates the investor for the time value of money and the expected inflation rate over the investment period. The frequently adopted proxy for the risk free rate is the long-term Government bond rate.

We have considered the yield to maturity of the zero coupon 20-year US Government bond as a proxy for the long-term risk free rate in US. As the majority of the cash flows of each asset are earned in USD, we have not adjusted the risk free rate for any inflation differential between the US and the countries in which the assets operate.

In determining an international risk free rate for each of the assets we have taken the 5-day average yield to maturity of the 20-year US Government treasury constant maturity as at 28 May 2014 of 3.12%. This rate represents a nominal rate and thus includes inflation.

Equity market risk premium (EMRP)

The EMRP (Rm – Rf) represents the risk associated with holding a market portfolio of investments, that is, the excess return a shareholder can expect to receive for the uncertainty of investing in equities as opposed to investing in a risk free alternative. The size of the EMRP is dictated by the risk aversion of investors – the lower (higher) an investor's risk aversion, the smaller (larger) the equity risk premium.

The EMRP is not readily observable in the market and therefore represents an estimate based on available data. There are generally two main approaches used to estimate the EMRP, the historical approach and the prospective approach, neither of which is theoretically more correct or without limitations. The former approach relies on historical share market returns relative to the returns on a risk free security; the latter is a forward looking approach which derives an estimated EMRP based on current share market values and assumptions regarding future dividends and growth.

In evaluating the EMRP, we have considered both the historically observed and prospective estimates of EMRP.

The historical approach is applied by comparing the historical returns on equities against the returns on risk free assets such as Government bonds, or in some cases, Treasury bills. The historical EMRP has the benefit of being capable of estimation from reliable data; however, it is possible that historical returns achieved on stocks were different from those that were expected by investors when making investment decisions in the past and thus the use of historical market returns to estimate the EMRP would be inappropriate.

It is also likely that the EMRP is not constant over time as investors' perceptions of the relative riskiness of investing in equities change. Investor perceptions will be influenced by several factors such as current economic conditions, inflation, interest rates and market trends. The historical risk premium assumes the EMRP is unaffected by any variation in these factors in the short to medium term.

Historical estimates are sensitive to the following:

- the time period chosen for measuring the average
- the use of arithmetic or geometric averaging for historical data

- selection of an appropriate benchmark risk free rate
- the impact of franking tax credits
- exclusion or inclusion of extreme observations.

The EMRP is highly sensitive to the different choices associated with the measurement period, risk free rate and averaging approach used and as a result estimates of the EMRP can vary substantially.

Data provided by the Morningstar 'Stocks, Bonds, Bills and Inflation Yearbook' (SBBI) for 2013 was considered in estimating the EMRP. The SBBI calculates the market equity risk premium by reducing large-company stock returns by the risk-free rate of return over the period from 1926 to 2012. To match the EMRP with the risk free rate included in the CAPM, we have considered the premium calculated over the return on the long-term US Treasury strips. Further adjustments were made to the SBBI equity risk premium in order to account for the inflation in the market price to earnings ratio as well as recent declines in the risk-free rate.

In addition to the data provided by the SBBI, consideration was also given to the equity risk premium implied by the dividend discount model for a broad market index such as the Standard and Poor's 500.

Based the above, we have adopted an US EMRP of 5.75%.

Beta estimate (β)

Description

The beta coefficient measures the systematic risk or non-diversifiable risk of a company in comparison to the market as a whole. Systematic risk, as separate from specific risk as discussed below, measures the extent to which the return on the business or investment is correlated to market returns. A beta of 1.0 indicates that an equity investor can expect to earn the market return (i.e. the risk free rate plus the EMRP) from this investment (assuming no specific risks). A beta of greater than one indicates greater market related risk than average (and therefore higher required returns), while a beta of less than one indicates less risk than average (and therefore lower required returns).

Betas will primarily be affected by three factors which include:

- the degree of operating leverage employed by the firm in that companies with a relatively high fixed cost base will be more exposed to economic cycles and therefore have higher systematic risk compared to those with a more variable cost base
- the degree of financial leverage employed by a firm in that as additional debt is employed by a firm, equity investors will demand a higher return to compensate for the increased systematic risk associated with higher levels of debt
- correlation of revenues and cash flows to economic cycles, in that companies that are more exposed to economic cycles (such as retailers), will generally have higher levels of systematic risk (i.e. higher betas) relative to companies that are less exposed to economic cycles (such as regulated utilities).

The geared or equity beta can be estimated by regressing the returns of the business or investment against the returns of an index representing the market portfolio, over a reasonable time period. However, there are a number of issues that arise in measuring historical betas that can result in differences, sometimes significant, in the betas observed depending on the time period utilised, the benchmark index and the source of the beta estimate. For unlisted companies it is often preferable to have regard to sector averages or a pool of comparable companies rather than any single company's beta estimate due to the above measurement difficulties.

Market evidence

In estimating an appropriate beta for Horizon and the Proposed Merged Entity we have considered the betas of a suite of listed companies that are comparable to Horizon and the Proposed Merged Entity. However, many of these companies do not have sufficient trading in their shares to provide a meaningful representation of an appropriate beta for Horizon and the Proposed Merged Entity. We have therefore only presented the benchmarks of those companies considered to have sufficiently liquid trading in their shares.

These betas, which are presented below, have been calculated based on weekly and monthly returns, over a two and four year period, compared to a relevant domestic index and the Morgan Stanley Capital International World Index (MSCI Index).

Table 38

Entity	Enterprise value (USD million)	debt to enterprise value	Two-year weekly returns: Domestic levered beta	Domestic unlevered beta	International levered beta	International unlevered beta	Four-year monthly returns: Domestic levered beta	Domestic unlevered beta	International levered beta	International unlevered beta
Horizon	613	19%	0.94	0.76	0.61	0.49	2.13	1.82	1.66	1.42
ROC	252	0%	1.05	1.05	0.37	0.37	1.46	1.46	0.91	0.91
Australian listed companies – large										
Woodside Petroleum Limited	33,276	10%	1.10	1.03	0.58	0.54	1.31	1.21	0.76	0.71
Santos Limited	17,427	12%	1.26	1.08	0.68	0.59	1.14	1.05	0.59	0.54
Oil Search Limited	16,864	14%	1.00	0.84	0.54	0.45	0.97	0.88	0.69	0.62
Australian / New Zealand listed companies – medium to small										
Beach Energy Limited	1,729	0%	1.53	1.53	0.71	0.71	1.34	1.34	0.73	0.73
AWE Limited	725	1%	1.43	1.41	0.81	0.80	1.35	1.34	0.83	0.83
Drillsearch Energy, Limited	689	6%	1.56	1.45	0.30	0.28	1.65	1.59	1.37	1.32
Senex Energy Limited	638	0%	1.85	1.85	0.75	0.75	1.61	1.61	1.35	1.35
New Zealand Oil & Gas Limited	144	0%	0.42	0.42	0.37	0.37	0.85	0.85	0.61	0.61
Cooper Energy Limited	127	0%	0.96	0.96	0.99	0.99	1.20	1.20	0.94	0.94
Otto Energy Limited	109	4%	0.71	0.67	0.70	0.66	0.83	0.80	0.81	0.78
Kina Petroleum Limited	77	0%	0.42	0.42	0.27	0.27	0.31	0.31	0.11	0.11
Carnarvon Petroleum Limited	71	0%	1.92	1.92	0.95	0.95	1.91	1.91	1.37	1.37
Tap Oil Limited	65	0%	0.89	0.89	0.60	0.60	1.79	1.79	1.35	1.35
Cue Energy Resources Limited	29	1%	0.91	0.91	0.03	0.03	0.89	0.89	0.63	0.63
Average (Australian companies)		**3%**	**1.12**	**1.08**	**0.58**	**0.55**	**1.30**	**1.25**	**0.92**	**0.89**
International companies										
Inpex Corporation	18,754	0%	0.80	0.80	0.99	0.99	0.63	0.63	0.98	0.98
Premier Oil plc	4,439	24%	1.29	0.97	1.06	0.80	1.36	1.10	0.95	0.77
SOCO International plc	2,129	0%	0.86	0.86	0.64	0.64	0.67	0.67	0.26	0.26
PT Medco Energi Internasional Tbk	1,459	39%	0.26	0.17	0.16	0.10	0.16	0.11	0.56	0.38
PT Energi Mega Persada Tbk	913	49%	0.93	0.45	0.45	0.22	1.64	0.95	1.53	0.89
Salamander Energy plc	866	26%	0.76	0.60	0.60	0.47	1.15	0.91	1.01	0.80
KrisEnergy Limited	526	0%	0.43	0.43	0.37	0.37	0.47	0.47	0.41	0.41
RH PetroGas Limited	504	11%	0.69	0.63	nm	nm	0.98	0.89	0.89	0.81
Niko Resources Limited	490	36%	1.99	1.16	1.08	0.63	1.85	1.31	0.87	0.61

Entity	Enterprise value (USD million)	debt to enterprise value	Two-year weekly returns: Domestic levered beta	Two-year weekly returns: Domestic unlevered beta	Two-year weekly returns: International levered beta	Two-year weekly returns: International unlevered beta	Four-year monthly returns: Domestic levered beta	Four-year monthly returns: Domestic unlevered beta	Four-year monthly returns: International levered beta	Four-year monthly returns: International unlevered beta
Average		**20%**	**0.89**	**0.67**	**0.67**	**0.53**	**0.99**	**0.78**	**0.83**	**0.66**
Average		**10%**	**1.04**	**0.93**	**0.62**	**0.56**	**1.13**	**1.04**	**0.85**	**0.77**
Median		**1%**	**0.93**	**0.89**	**0.62**	**0.59**	**1.15**	**0.95**	**0.83**	**0.77**
Low		**0%**	**0.26**	**0.17**	**0.03**	**0.03**	**0.16**	**0.11**	**0.11**	**0.11**
High		**49%**	**1.99**	**1.92**	**1.08**	**0.99**	**1.91**	**1.91**	**1.53**	**1.37**

Source: Capital IQ; Deloitte Corporate Finance analysis
Notes:
1. *Enterprise value as at 23 May 2014*
2. *nm: not meaningful*

The observed beta is a function of the underlying risk of the cash flows of the company, together with the capital structure and tax position of that company. This is described as the levered beta.

The capital structure and tax position of the entities in the table above may not be the same as those of Horizon and the Proposed Merged Entity. The levered beta is often adjusted for the effect of the capital structure and tax position. This adjusted beta is referred to as the unlevered beta. The unlevered beta is a reflection of the underlying risk of the pre-financing cash flows of the entity.

Selected beta (β)

In selecting an appropriate beta for Horizon and the Proposed Merged Entity we have considered the following:

- oil and gas production and exploration assets have varying risk profiles depending on the maturity of the asset and the stage of its development. In considering an appropriate beta for Horizon and the Proposed Merged Entity, we have placed more emphasis on companies in the conventional oil and gas sector and which have producing assets. The additional risks associated with the development projects in PNG are reflected in risk factors directly applied to the cash flows
- most of the comparable companies are similar to Horizon and the Proposed Merged Entity as they have interests in international oil and gas assets. Accordingly, these companies are likely to face a number of similar opportunities and risks compared to Horizon and the Proposed Merged Entity
- the overall average two year weekly unlevered beta of all the comparable companies selected, measured against the relevant domestic and MSCI index is 0.93 and 0.56, respectively. The overall average four year monthly unlevered beta of all the comparable companies selected, measured against the relevant domestic and MSCI index is 1.04 and 0.77, respectively
- we consider AWE Limited to be most comparable to Horizon and the Proposed Merged Entity in terms of size and asset diversity. The average two year weekly unlevered beta for AWE Limited is 1.41 and 0.80 based on the domestic Index and MSCI Index, respectively. The average four year monthly unlevered beta for AWE Limited is 1.34 and 0.83 based on the domestic Index and MSCI Index, respectively.
- Woodside and Santos are both engaged in the production of natural gas and oil and are exposed to the LNG market via existing LNG plants in Western Australia (Woodside) and the Northern Territory (Santos), and the development of new LNG plants. Furthermore, both companies have interests in various Australian and international oil producing and exploration assets. Notwithstanding their oil, gas and LNG activities, we consider these companies are only broadly comparable with Horizon and the Proposed Merged Entity as Woodside and Santos are significantly larger and more diversified and therefore face a number of different opportunities and risks
- assuming an unlevered beta of 1.10 to 1.20, the corporate tax rates relevant to each jurisdiction and the debt to enterprise value ratio of 20% results in Blume adjusted relevered betas as follows:

Table 39

Asset location	Beta (low)	Beta (low)
Australia	1.20	1.27
China	1.20	1.28
Malaysia	1.20	1.28
New Zealand	1.20	1.28
PNG	1.20	1.27
UK	1.20	1.27

Source: Deloitte Corporate Finance analysis

Specific company (asset) risk premium (α)

The specific company (or asset) risk premium adjusts the cost of equity for asset specific factors, including unsystematic risk factors such as:

- size of operations
- depth and quality of management
- reliance on one key individual or a few key members of management

- reliance on key customers
- reliance on key suppliers
- product diversity (limits on potential customers)
- geographic diversity
- labour relations, quality of personnel (union/non-union)
- capital structure, amount of leverage
- existence of contingent liabilities.

The CAPM assumes, amongst other things, that rational investors seek to hold efficient portfolios, that is, portfolios that are fully diversified. One of the major conclusions of the CAPM is that investors do not have regard to specific company or asset risks (often referred to as unsystematic risk).There are several empirical studies that demonstrate that the investment market does not ignore specific company or asset risks. In particular, studies show that:

- on average, smaller companies have higher rates of return than larger companies (often referred to as the size premium)
- on average, early stage companies have higher rates of return than mature companies.

Selection of specific asset risk premium

With the exception of country-specific risk, we have incorporated any specific asset risks in our projected cash flows assumptions for the various assets.

The CRP is the risk arising from an unpredictable change in government policy or behaviour of a regulatory agency and other risks attributable to an unstable political or civil environment. Market perception of country risk is subjective and conclusions drawn require the exercise of professional judgement. To arrive at a reasonable approximation of the additional return required to compensate for the risk inherent in investing in different countries we have had regard to a variety of external evidence, including:

- current general macroeconomic and political conditions facing each country
- country ratings attributed by ratings agencies such as Moody’s, Standard & Poor’s (S&P), and other market analysts such as EIU
- the differential between US Government bond rates and USD-denominated government bonds issued by countries with a similar credit rating to each country.

We have also had regard to the differential between US Government bond rates and USD-denominated government bonds issued by these countries. Some countries generally do not issue any USD-denominated Government bonds and so we have also considered USD-denominated Government bonds issued by countries with a similar credit risk rating to the countries in which the assets are located. We have compared their yields to the yield on US Government bonds of a similar maturity to determine an implied CRP. The results of the analysis are viewed as a guide for an appropriate CRP for each country.

Based on our analysis, we have selected the following country risk premiums:

Table 3

	Selected CRP
Australia	-
China	1.50
Malaysia	2.00
New Zealand	-
PNG	4.00
UK	-

Source: Deloitte Corporate Finance analysis

Dividend imputation

Dividends paid by Australian corporations may be franked, unfranked, or partly franked. A franked dividend is one that is paid out of company profits which have borne tax at the company rate, currently 30%. Where the shareholder is an Australian resident individual or complying superannuation fund, it will generally be entitled to a tax credit (called an imputation credit) in respect of the tax paid by the company on the profits out of which the dividend was paid. If the recipient of the dividend is another company, the dividend will give rise to a credit in that company's franking account thereby increasing the potential of the company to pay a franked dividend at a later stage.

We have not adjusted the cost of capital or the projected cash flows for the impact of dividend imputation due to the diverse views as to the value of imputation credits and the appropriate method that should be employed to calculate this value. Determining the value of franking credits requires an understanding of shareholders' personal tax profiles to determine the ability of shareholders to use franking credits to offset personal income. Furthermore, the observed EMRP already includes the value that shareholders ascribe to franking credits in the market as a whole. In our view, the evidence relating to the value that the market ascribes to imputation credits is inconclusive.

Conclusion on cost of equity

Based on the above factors we arrive at a cost of equity, K_e, for the assets as follows:

Table 40

		Risk free rate	EMRP	Beta	CRP	K_e – calculated
Beibu Gulf	Low	3.12%	5.75%	1.20	1.50%	11.54%
	High	3.12%	5.75%	1.28	1.50%	12.00%
Bohai Bay	Low	3.12%	5.75%	1.20	1.50%	11.54%
	High	3.12%	5.75%	1.28	1.50%	12.00%
D35 / D21 / J4 PSC	Low	3.12%	5.75%	1.20	2.00%	12.04%
	High	3.12%	5.75%	1.28	2.00%	12.50%
Maari / Manaia	Low	3.12%	5.75%	1.20	-	10.01%
	High	3.12%	5.75%	1.28	-	10.46%
Stanley	Low	3.12%	5.75%	1.20	4.00%	13.99%
	High	3.12%	5.75%	1.27	4.00%	14.44%
Elevala-Ketu	Low	3.12%	5.75%	1.20	4.00%	13.99%
	High	3.12%	5.75%	1.27	4.00%	14.44%
Cliff Head	Low	3.12%	5.75%	1.20	-	9.99%
	High	3.12%	5.75%	1.27	-	10.44%
Blane	Low	3.12%	5.75%	1.20	-	9.99%
	High	3.12%	5.75%	1.27	-	10.44%
Enoch	Low	3.12%	5.75%	1.20	-	9.99%
	High	3.12%	5.75%	1.27	-	10.44%

Source: Deloitte Corporate Finance analysis

Cost of debt capital (K_d)

We have estimated the cost of debt for Horizon and the Proposed Merged Entity to be 7.0%. This has been estimated after consideration of the following:

- Horizon's current cost of debt for bank borrowings based on the London Interbank Offered Rate[33] (Libor) plus a weighted average margin of 3.5%, whilst Horizon's Convertible Bonds carry a 7.0% yield to maturity
- an analysis of comparable issuances indicate a spread of 200 to 300 basis point margin over the risk free rate
- Horizon and the Proposed Merged Entity's exposure to the PNG assets, which are riskier relative to the other assets in their portfolios
- our selected level of gearing, as discussed below
- the average cost of debt of listed comparable companies.

Debt and equity mix

We have considered the following factors in estimating the debt to equity mix for Horizon and the Proposed Merged Entity:

- the four year average gearing level of Horizon and ROC is 19% and nil, respectively
- the range of gearing levels for the comparable companies set out in Table 38
- current gearing levels of oil and gas production and exploration companies have been distorted compared to long term trends due to very strong cash flows generated as a consequence of the recent high commodity prices.

We have adopted a target gearing level of 20%.

Calculation of WACC

Based on the above, we have assessed the nominal post-tax WACC for the assets to be:

Table 41

Input		Cost of equity capital	Cost of debt capital	Debt to enterprise value ratio	Tax rate	WACC	Selected WACC
Beibu Gulf	Low	11.54%	7.00%	20.00%	25.00%	10.29%	10.00%
	High	12.00%	7.00%	20.00%	25.00%	10.65%	11.00%
Bohai Bay	Low	11.54%	7.00%	20.00%	25.00%	10.29%	10.00%
	High	12.00%	7.00%	20.00%	25.00%	10.65%	11.00%
D35 / D21 / J4 PSC	Low	12.04%	7.00%	20.00%	25.00%	10.69%	10.50%
	High	12.50%	7.00%	20.00%	25.00%	11.05%	11.50%
Maari / Manaia	Low	10.01%	7.00%	20.00%	28.00%	9.02%	9.00%
	High	10.46%	7.00%	20.00%	28.00%	9.38%	10.00%
Stanley	Low	13.99%	7.00%	20.00%	30.00%	12.17%	12.00%
	High	14.44%	7.00%	20.00%	30.00%	12.53%	13.00%
Elevala-Ketu	Low	13.99%	7.00%	20.00%	30.00%	12.17%	12.00%

[33] Based on the one year LIBOR

Input		Cost of equity capital	Cost of debt capital	Debt to enterprise value ratio	Tax rate	WACC	Selected WACC
	High	14.44%	7.00%	20.00%	30.00%	12.53%	13.00%
Cliff Head	Low	9.99%	7.00%	20.00%	30.00%	8.97%	9.00%
	High	10.44%	7.00%	20.00%	30.00%	9.33%	10.00%
Blane	Low	9.99%	7.00%	20.00%	30.00%	8.97%	9.00%
	High	10.44%	7.00%	20.00%	30.00%	9.33%	10.00%
Enoch	Low	9.99%	7.00%	20.00%	30.00%	8.97%	9.00%
	High	10.44%	7.00%	20.00%	30.00%	9.33%	10.00%

Source: Deloitte Corporate Finance analysis

Appendix E: Selected comparable entities

Table 42

	Enterprise value (USD million)	Total 2P certified reserves (mmboe)	Enterprise value / mmboe
Australian listed companies – large			
Woodside Petroleum Limited	33,276	1,437	23.2x
Santos Limited	17,427	1,368	12.7x
Oil Search Limited	16,864	527	32.0x
Australian and New Zealand listed companies – medium to small			
Beach Energy Limited	1,729	93	18.7x
AWE Limited	725	83	8.7x
Drillsearch Energy, Limited	689	29	24.2x
Senex Energy Limited	638	37	17.1x
New Zealand Oil & Gas Limited	144	10	14.0x
Cooper Energy Limited	127	2	58.7x
Otto Energy Limited	109	4	26.6x
Kina Petroleum Limited	77	n/a	n/a
Carnarvon Petroleum Limited	71	12	5.8x
Tap Oil Limited	65	6	10.7x
Cue Energy Resources Limited	29	5	5.5x
Average (Australian and New Zealand listed companies)			**19.9x**
International companies			
Inpex Corporation	18,754	4,477	4.6x
Premier Oil plc	4,439	259	17.1x
SOCO International plc	2,129	130	16.4x
PT Medco Energi Internasional Tbk.	1,459	263	5.6x
PT Energi Mega Persada Tbk	913	230	4.1x
Salamander Energy plc	866	65	13.3x
KrisEnergy Ltd.	526	32	16.3x
RH PetroGas Limited	504	11	44.8x

	Enterprise value (USD million)	Total 2P certified reserves (mmboe)	Enterprise value / mmboe
Niko Resources Limited	490	150	3.3x
Average		**624**	**13.9x**
Average			**17.3x**
Median			**15.2x**
High			**58.7x**
Low			**3.3x**

Source: Mergermarket; Capital IQ; ASX announcements; Deloitte Corporate Finance analysis

Notes:

1. *Enterprise values (as at 23 May 2014) and multiples presented on a minority interest basis*

Appendix F: Selected comparable transactions

Table 43

Announcement date	Bidder	Target	Implied enterprise value (USD million)	2P certified reserves (mmboe)	Enterprise value / mmboe
18-Feb-14	Central Petroleum Limited	Magellan Petroleum (NT) Pty Limited	38	10	3.8x
22-Oct-13	SapuraKencana Petroleum Berhad	Newfield Malaysia Holdings	896	36	24.9x
02-Oct-13	Pan Pacific Petroleum NL; New Zealand Oil & Gas Limited; AWE Limited	The Tui Area Oil Project	43	5	8.2x
22-Aug-13	Santos Limited	AWE Limited, Northwest Natuna PSC	288	101	2.9x
04-Jul-13	Drillsearch Energy Limited	Tintaburra Block	116	5	22.3x
19-Apr-13	Energi Mega Persada Tbk PT	Tonga PSC	75	3	22.2x
28-Feb-13	PT Saka Energi Indonesia	Ketapang Block in Indonesia	375	83	4.5x
26-Jul-12	Mattvale Pty Limited	Bridgeport Energy Limited	73	3	23.5x
23-May-12	The Hong Kong and China Gas Company Limited	Pan Orient Energy (Thailand) Limited	173	30	5.8x
Average					**13.1x**
Median					**8.2x**
High					**24.9x**
Low					**2.9x**

Source: Mergermarket; Capital IQ; ASX announcements; Deloitte Corporate Finance analysis

Appendix G: Technical expert's report

INDEPENDENT TECHNICAL SPECIALIST REPORT ON THE PETROLEUM PROPERTIES OF ROC OIL COMPANY LIMITED AND HORIZON OIL LIMITED
FOR
DELOITTE CORPORATE FINANCE PTY LIMITED

Strictly Confidential

June 2014

DECISIONS WITH CONFIDENCE

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1. SUMMARY

1.1. OVERVIEW

The document comprises the Independent Technical Specialists Report by RISC Operations Pty Ltd (RISC) to assist the Independent Expert Deloitte Corporate Finance Pty Limited (Deloitte) in the preparation of an Independent Expert's Report to the Directors of Horizon Oil Limited (Horizon) on the proposed merger of Horizon and Roc Oil Company Limited (Roc). The location of the petroleum properties and interests of both companies are shown in Figure 1-1 and Figure 1-2.

The report documents our review of the petroleum reserves, resources and associated development schedules, production and cost forecasts (projects) provided by Horizon and Roc 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 audited the estimates provided by both companies 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 both companies.

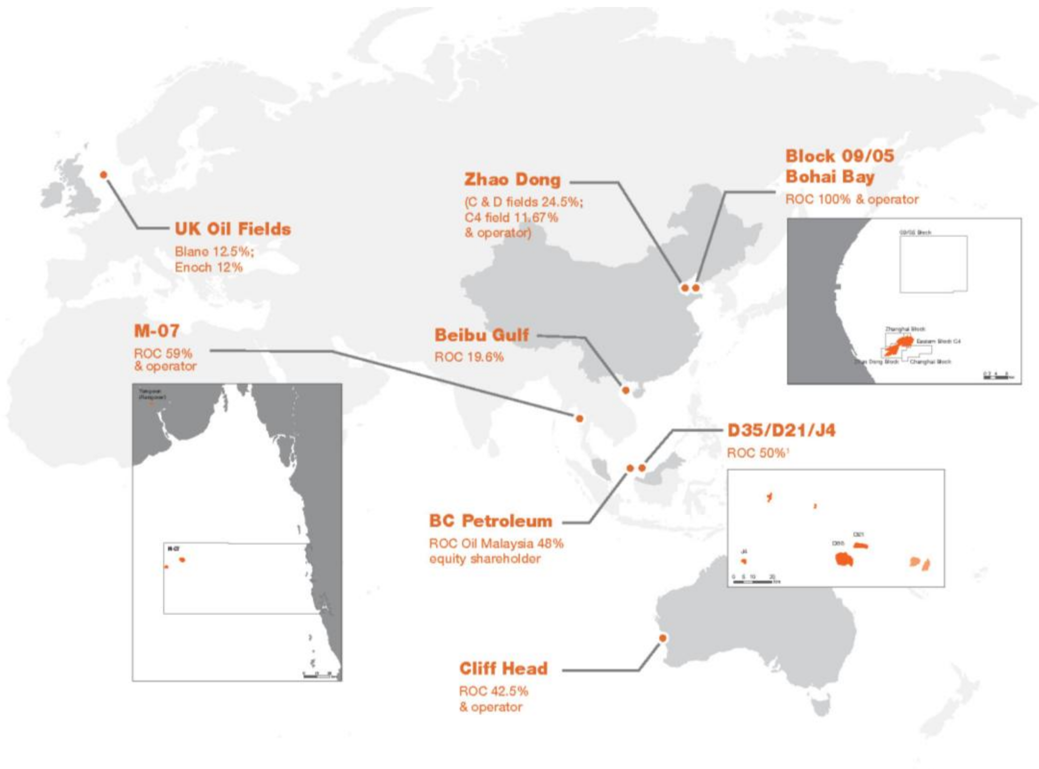

Figure 1-1 Location Map Roc Oil and Gas Properties

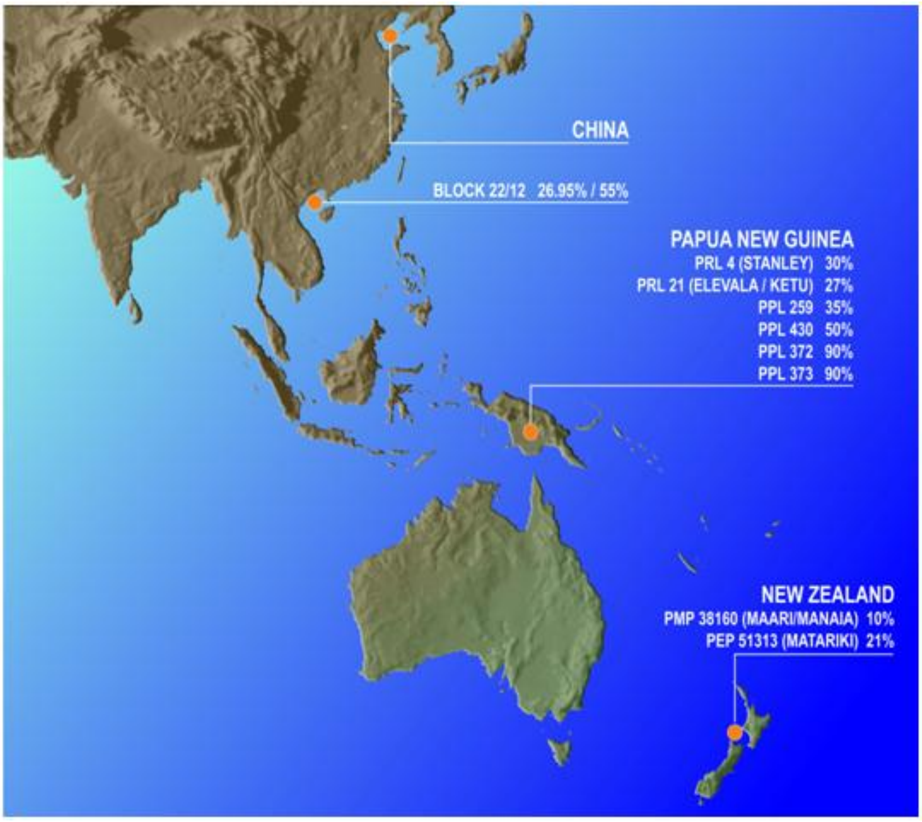

Figure 1-2 Location Map Horizon Oil and Gas Properties

The reserves and contingent resources of both companies assessed in this report are shown in Table 1-1, Table 1-2, Table 1-3, Table 1-4.

Details of the costs and production profiles associated with the development and production of these resources are included in our report.

Area	Gross 2P Reserves		Working Interest	Net WI 2P Reserves	
	Oil MMstb	Gas Bcf	%	Oil MMstb	Gas Bcf
Australia	5.1	0.0	42.5%	2.2	0
United Kingdom	12.0	0.7	12.5%	1.5	0.1
Bohai Bay[1]	17.5	4.8	11.7-25.4%	4.1	1.1
Beibu Gulf[1]	24.4	0.0	19.6%	4.8	0
D35/J4/D21[1]	27.6	42.9	30%[2]	8.3	12.9
Total	**86.6**	**48.4**		**20.9**	**14.1**
1. Reserve and resource entitlement is determined by the net economic interest which is a function of the PSC terms, costs and prices prevailing during the PSC term. Depending on these factors, there may be a material difference between the working interest and the net economic interest.					
2. Subject to Petronas approval					

Table 1-1 Roc Gross and Working Interest 2P Reserves at 1/1/2014

Area	Gross 2C Resources		Working Interest	Net WI 2C Resources	
	Oil MMstb	Gas Bcf	%	Oil MMstb	Gas Bcf
Australia	5.3	0.0	42.5%	2.3	0
United Kingdom	7.3	50.0	12.5%	0.9	6.3
Bohai Bay[1]	21.6	4.9	11.7-25.4%	5.1	1.1
Beibu Gulf[1]	11.5	0.0	40.0%[2]	4.6	0.1
D35/J4/D21[1]	96.0	71.9	30.0%[3]	28.8	21.6
Total	**141.7**	**126.8**		**41.7**	**29.1**
1. Reserve and resource entitlement is determined by the net economic interest which is a function of the PSC terms, costs and prices prevailing during the PSC term. Depending on these factors, there may be a material difference between the working interest and the net economic interest.					
2. CNOOC has the right to back in for 51% reducing the 40% interest to 19.6%					
3. Subject to Petronas approval					

Table 1-2 Roc Gross and Working Interest 2C Contingent Resources at 1/1/2014

Area	Gross 2P Reserves		Working Interest	Net WI 2P Reserves	
	Oil MMstb	Gas Bcf	%	Oil MMstb	Gas Bcf
New Zealand	59.5	0	10.0%	6.0	0
Beibu Gulf[1]	24.4	0	26.95%	6.6	0
PNG	11.4	0	30.0%[2]	3.4	0
Total	**95.3**	**0**		**16.0**	**0**
1. Reserve and resource entitlement is determined by the net economic interest which is a function of the PSC terms, costs and prices prevailing during the PSC term. Depending on these factors, there may be a material difference between the working interest and the net economic interest.					
2. PNG Govt has the right to back in for up to 22.5%, reducing the 30% interest to 23.25%					

Table 1-3 Horizon Gross and Working Interest 2P Reserves at 1/1/2014

Area	Gross 2C Resources		Working Interest	Net WI 2C Resources	
	Oil MMstb	Gas Bcf	%	Oil MMstb	Gas Bcf
New Zealand	0.9	0	10.0%	0.1	0.0
Beibu Gulf[1]	11.5	0	55.0%[2]	6.3	0.0
PNG	50.9	1378	27.0-30.0%[3]	13.8	384.0
Total	**63.3**	**1378.0**		**20.2**	**384.0**
1. Reserve and resource entitlement is determined by the net economic interest which is a function of the PSC terms, costs and prices prevailing during the PSC term. Depending on these factors, there may be a material difference between the working interest and the net economic interest.					
2. CNOOC has the right to back in for 51% reducing the 55% interest to 26.95%					
3. PNG Govt has the right to back in for up to 22.5%, reducing the 30% interest to 23.25% and the 27% interest to 20.9%					

Table 1-4 Horizon Gross and Working Interest 2C Contingent Resources at 1/1/2014

1.2. EXPLORATION VALUATION

RISC has assessed the fair market value of Roc's and Horizon's exploration interests using a combination of methods including value of the work program, farmin promotes from comparable transactions and expected monetary value (EMV), the basis of which is included in our report. Our estimates are summarised in Table 1-5 and Table 1-6.

Asset	Fair Market Value US$ million Horizon net working interest		
	Low	Mid	High
New Zealand	7.6	7.6	15.2
China	0.0	4.4	8.8
PNG	16.1	20.1	66.3
Total	**23.7**	**32.1**	**90.3**

Table 1-5 Exploration Valuation - Horizon Net Working Interest

Asset	Fair Market Value US$ million Roc net working interest		
	Low	Mid	High
Australia	0.0	0.0	8.5
China	15.7	18.9	33.0
Malaysia	0.0	10.5	18.5
Myanmar	0.0	1.7	1.7
Total	**15.7**	**31.1**	**61.7**

Table 1-6 Exploration Valuation - Roc Net Working Interest

2. TERMS OF REFERENCE

Deloitte has requested RISC to provide the following services (the Services) to assist Deloitte to prepare the Independent Expert's Report (IER):

- input and advice on the appropriateness of the assumptions adopted in the financial models for Horizon and Roc (the Models), namely:
  - the level of reserves and resources
  - production profiles (including production profiles or potential expansion cases)
  - operating expenditure, including rehabilitation and abandonment costs
  - capital expenditure
  - any other assumptions you consider relevant.

  If you consider an assumption included in the Models to be unreasonable, you need to advise us and provide advice to enable us to make the appropriate changes to the Models to reflect a reasonable projection.
- provide a brief technical overview of the development and exploration assets in which Horizon and Roc have an interest
- assist with our assessment of the reasonableness of the assumptions for additional development scenarios, in the event that more than one development scenario is considered by us
- provide an opinion as to the fair market value of the exploration assets of Horizon and Roc
- assist with the estimation of tariffs for utilising gas export infrastructure for a gas price netback calculation
- prepare a short-form report (Report) summarising your findings, including your opinion as to the fair market value of the exploration assets of Horizon and Roc, and your findings relating to the underlying assumptions for each financial model. Your report will form part of the IER prepared by Deloitte Corporate Finance and may be provided (in part or full) to Horizon and its shareholders. We will discuss the form and content of your Report with you at the outset of this project

The Services exclude any work in relation to:

- marketing, commodity price and exchange rate assumptions adopted in the Models
- financial and / or corporate taxation analysis
- discount rate determination
- an assessment of the merits of the Proposed Scheme.

3. BASIS OF ASSESSMENT

The data and information used in the preparation of this report were provided by Roc and Horizon supplemented by public domain information. RISC has relied upon the information provided and has undertaken the evaluation on the basis of a review and audit 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 of both companies. We have carried out our valuation in accordance with the VALMIN code[2].

Unless otherwise stated, all resources are presented as gross quantities and costs are in US$ real terms with a reference date of 1 January 2014 (RT2014).

Exploration 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 exploration properties has been considered to determine value, which are described below.

Comparable Transactions

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.

Farmin

An estimate of Value can be based on an estimation of the share of future costs likely to be borne by a reasonable farminee under prevailing market conditions. A premium or promotion factor may be paid by the farminee. 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 farminee divided by the interest earned. The premium value for the permit is the difference between the nominal value and the cost of the activity.

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

[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

faminee paying the farmor a cash amount in return for the acquisition of the interest in the permit and is the fair market value.

Farmin transactions may have several stages. For example, a farminee 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.

Farmin 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 risk of occurring.

Work Program

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.

Expected Monetary Value (EMV)

EMV is the risked net present value (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 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.

4. AUSTRALIA

4.1. CLIFF HEAD

4.1.1. Field Description

The Cliff Head field is located in licence area WA-31-L in the Perth Basin, 10km offshore Western Australia in 15-20m of water. Roc holds a 42.5% working interest and is the Operator.

Figure 4-1 Location Map - Cliff Head

The field started production in May 2006 and in March 2014 gross oil production was 2.1 Mstb/d at 93% water cut and a GOR of 22 scf/stb. Cumulative production to 31 December 2013 was 13.6 MMstb.

Oil is trapped in Permian Dongara, Irwin River Coal Measures (IRCM) and underlying High Cliff Sandstone (HCS) reservoirs. The field comprises a main NW-SE trending horst, with a continuous large fault to the north, and a combination of overall dip closure and several fault segments to the south.

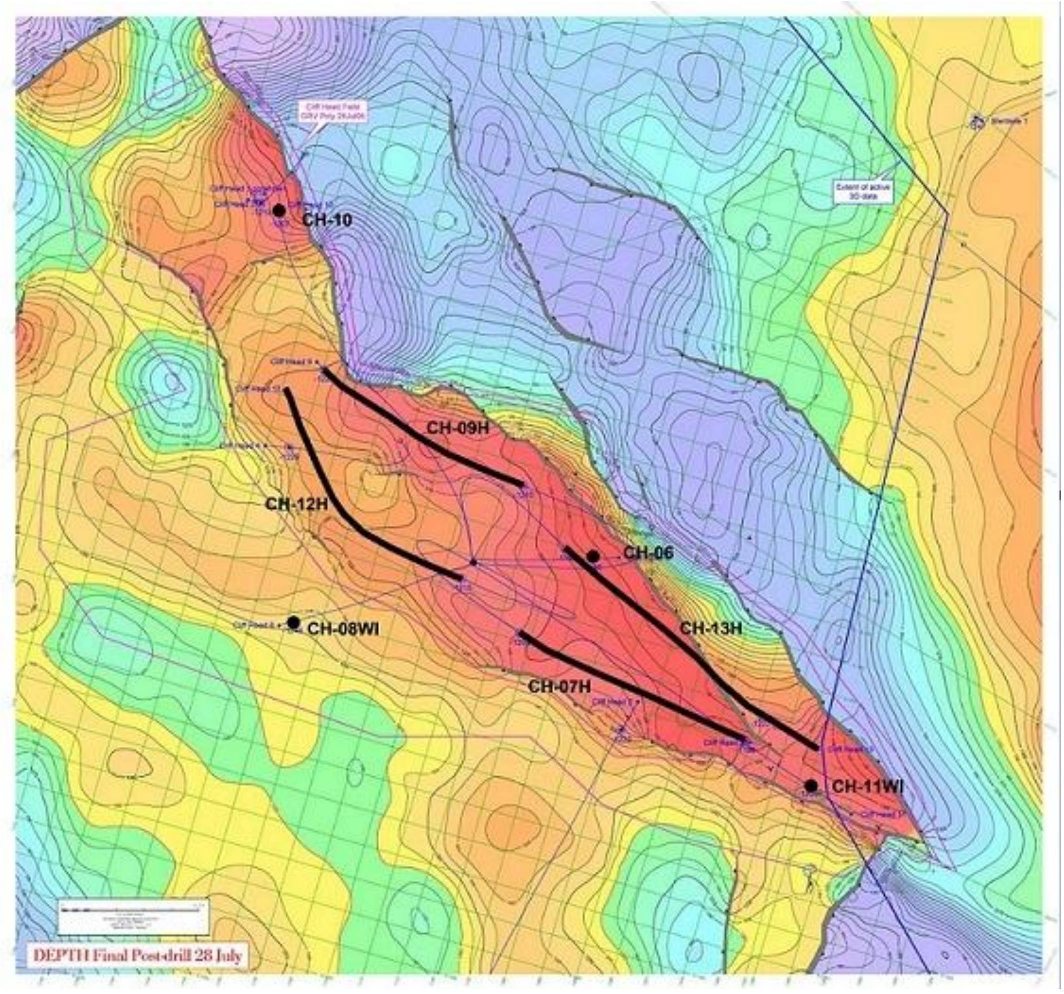

Figure 4-2 Top Reservoir Map - Cliff Head

The discovery well, Cliff Head-1 was drilled in December 2001. Five further appraisal wells, six production wells and two water injection wells have now been drilled, providing good structural control. A single oil water contact at 1,260 m TVDSS has been estimated from pressure gradient data.

The average net-to-gross ratio of the reservoir is about 87%, with average porosity about 18%. Permeabilities vary widely, from 1mD to over 1000 mD. Open fractures are reported from cored lower units of the Irwin River Coal Measures.

Offshore development consists of a minimum facility platform that is not normally manned. Electric Submersible Pumps (ESP) are installed in each producer to aid production and to allow increasing water cut. Routine ESP replacement upon failure will continue with an estimated 30 day turn around. Larger pumps have successfully been installed in CH-10 and CH-12 and are available for CH-07 and CH-13H when the current pumps fail. This will accelerate and provide incremental production before the economic cut-off. The reservoir has strong aquifer drive and sweep is supplement by produced water re-injection in wells CH-08 and more recently watered out producer CH-09H.

Oil processing is carried out onshore at the purpose built Arrowsmith processing plant from which the oil is transported by road tanker to the BP refinery at Kwinana. The export, production, road tanker and flow assurance facilities have been demonstrated to work with this waxy crude.

No further development is planned. However, an additional development well in the West High area has been under consideration for several years and the joint venture is looking at surfactant injection to reduce the fraction of residual oil and hence enhance the oil recovery.

4.1.2. Production and Cost forecast

Roc's 2P production and cost forecasts have been reviewed and are considered reasonable and consistent with RISC's 1 January 2014 reserves estimate. The ESP in CH-13 failed on 25-March-2014 and is planned to be replaced with a larger pump in May 2014. The forecast uptime is 92% including downtime caused by ESP failure and replacement.

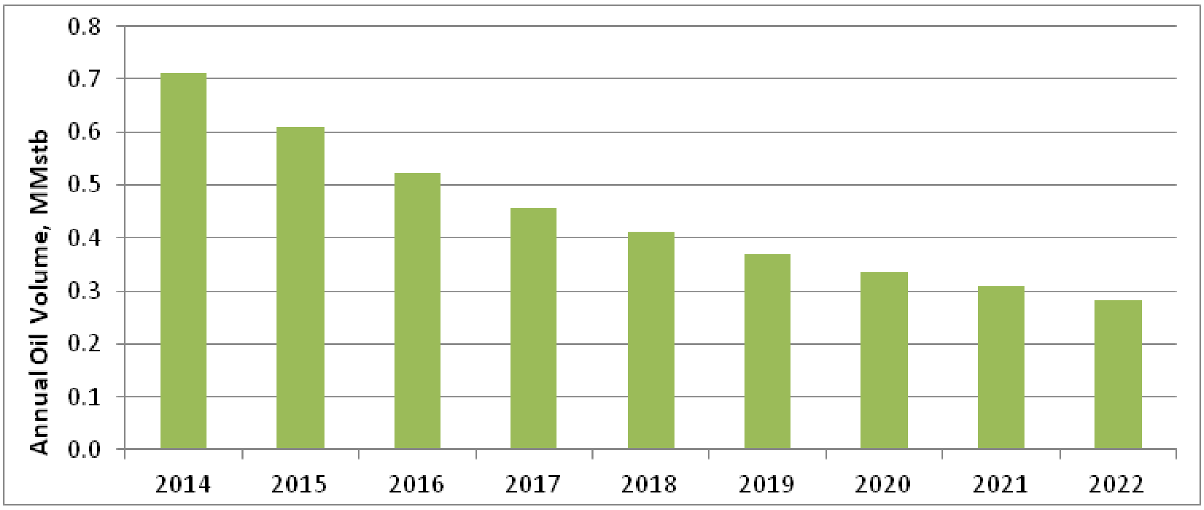

Figure 4-3 Gross 2P Production Forecast - Cliff Head

Figure 4-4 shows Roc's estimate for Cliff Head annual operating costs.

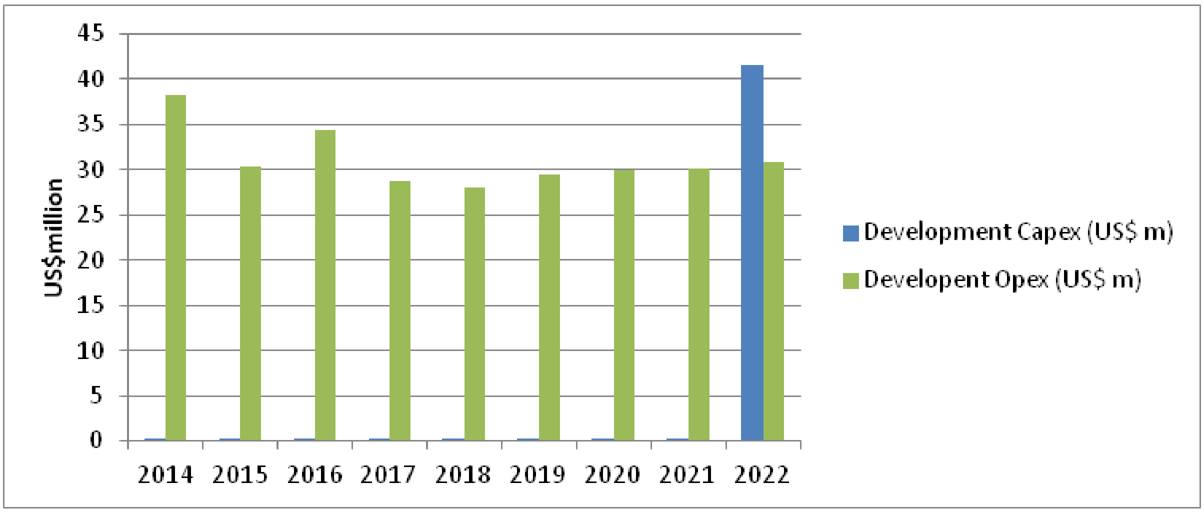

Figure 4-4 Gross Operating Cost Forecast - Cliff Head

Operating costs in 2014 are based on the work program and budget submitted to JV partners and included a contingent budget of A$15.8 million for; water injection pipeline repairs at A$1.5 million (though pipeline repairs are also included in the firm budget), enhanced oil recovery (EOR) implementation at A$6.0 million, two well interventions at A$3.2 million, engineering studies at A$1.7 million. RISC estimate that later in the field life there will be modest savings associated with reducing and ultimately eliminating non routine costs. To convert to US$ we have used an exchange rate of 0.9.

No further development capital expenditure is anticipated but Roc has included US$0.3 million p.a. for minor capital expenditure associated with upkeep of the facilities.

RISC has estimated the abandonment costs for the field to be US$34 million in 2014 real terms. This includes P&A expenditure for 9 wells and removal of the offshore platform and onshore production facilities. It is assumed that the pipelines will be cut and abandoned in-situ below the mud line.

Table 4-1 contains the reserves estimated by RISC.

	1P	2P	3P
Oil MMstb	3.4	5.1	6.7

Table 4-1 Gross Reserve Estimate at 1 January 2014 - Cliff Head

From the period 1 January 2014 to 31 March 2014 there has been a further depletion of 200,000 bbl gross due to production. There are no gas reserves in Cliff Head.

Contingent oil resources estimated by RISC for a West High well and EOR (surfactant injection) are shown in Table 4-2.

Gross Contingent Resources Oil (MMstb)	2C
West High well	1.3
EOR	4.0

Table 4-2 Gross 2C Contingent Resource Estimate at 1 January 2014 - Cliff Head

Roc is currently reviewing its portfolio of opportunities in and near Cliff Head with a view to identifying if commercially feasible projects exist.

4.2. EXPLORATION

Exploration prospectivity exists in the Mentelle prospect, which lies to the north east of the Cliff Head field and updip of well Mentelle-1 (Figure 4-5). The prospect is a rotated fault block with a gently westward dipping flank and fault bounded to the east. Mentelle-1 was drilled in 2003 and while it was dry, analysis of the well results suggests an 8m paleo-oil column below the regional seal. Roc believe that the prospect tilted post migration of oil and therefore the volume updip of the Mentelle well can be varied to give upside in the resources.

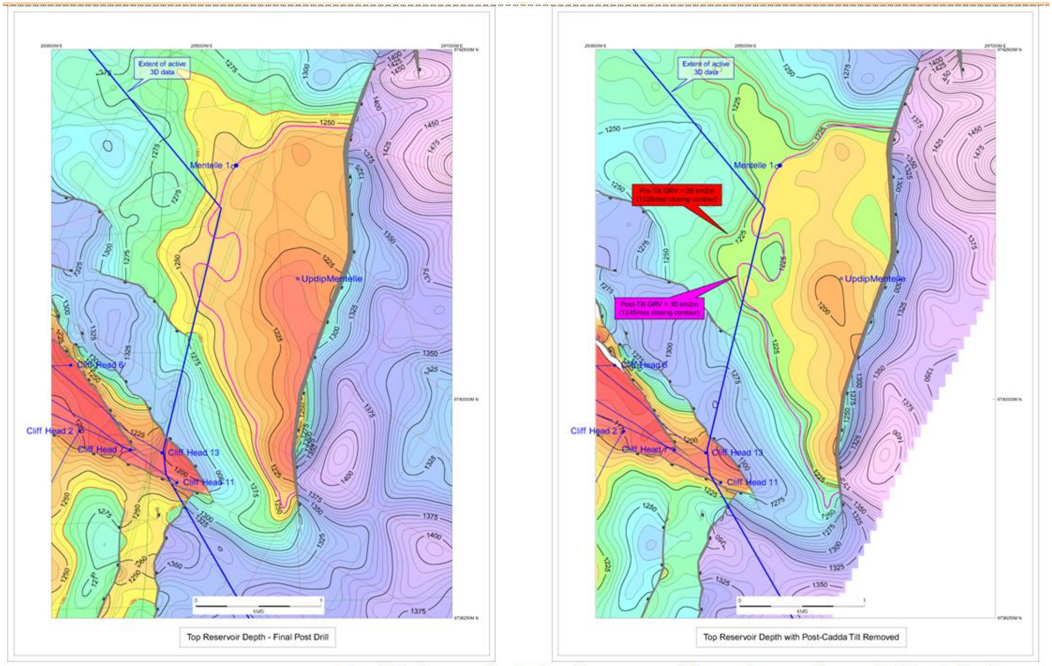

Figure 4-5 Mentelle depth maps post and pre-tilt

RISC considers Updip Mentelle as a valid exploration prospect and supports the prospective resources provided by Roc (Table 4-3).

RISC supports the prospect probability of success (POS) as assessed by Roc at 24%.

	Best Estimate MMstb
Mentelle Prospect	3.3

Table 4-3 Gross Best Estimate Prospective Resources as at 1 January 2014 - Mentelle Prospect

Whilst these resources are unlikely to interest a farminee at present volumes, costs and prices, there could be some value in the prospect in the future. In the low and mid cases, we have not assigned any value. In the high case, we have based the value on a 2:1 farmin promote of a well which gives a value net to Roc of $8.5 million

5. UNITED KINGDOM

5.1. BLANE AND ENOCH FIELD DESCRIPTION

Roc has a 12.50% unitised interest in Block 30/3A which contains the Blane field and a 12.501% unitised interest in Blocks 16/13a and 16/13E. Enoch is located in Block 16/13a.

Blane is a low relief anticlinal structure straddling the UK-Norway median line in the southern part of the North Sea Central Graben in 73m water depth.

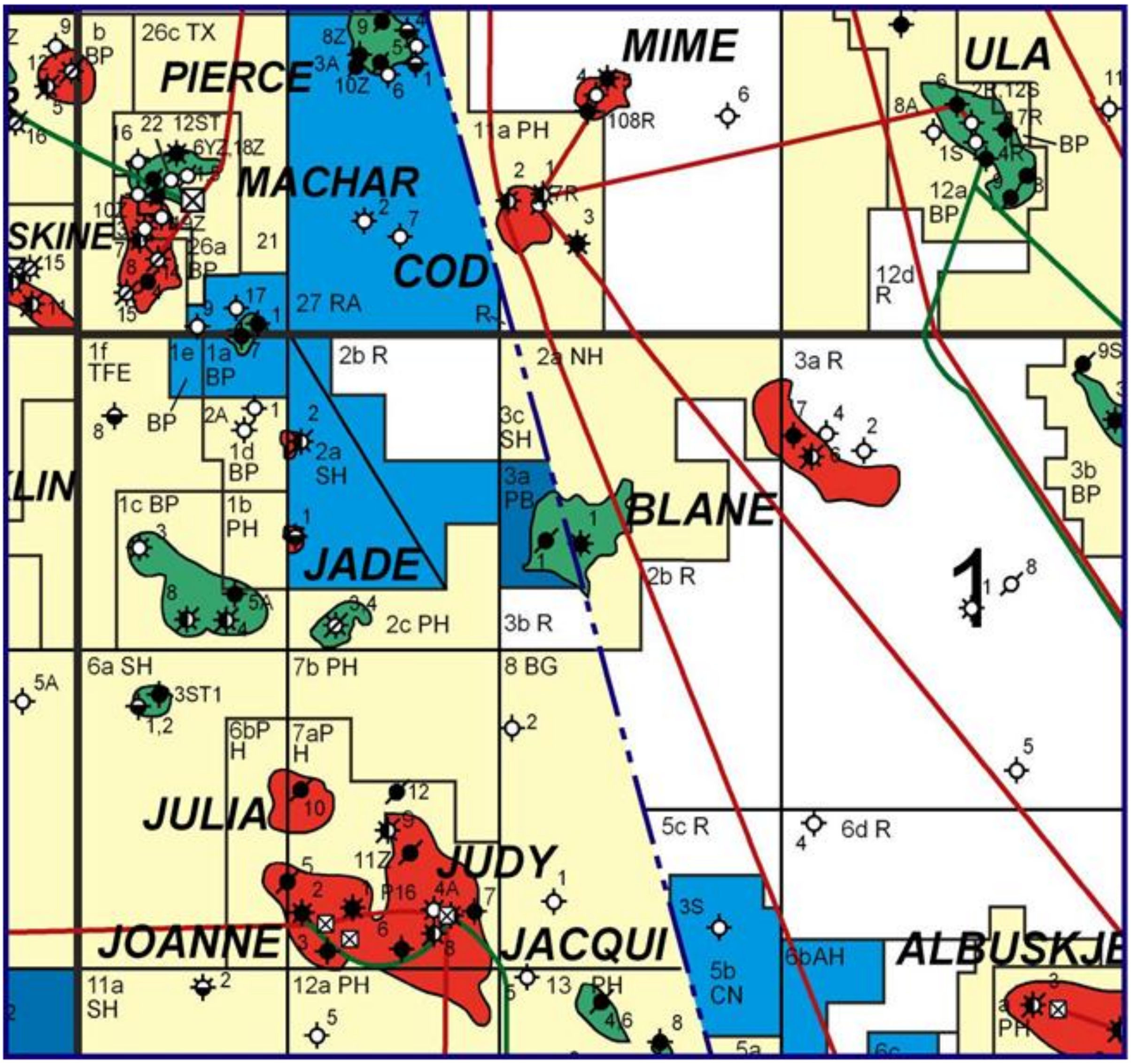

Figure 5-1 Location Map - Blane

The discovery well, N1/2-1 in the Norwegian sector and well 30/3a-1 in the UK sector were both drilled in 1989 and both tested light oil at rates in excess of 5,000 stb/d from the Palaeocene Forties Formation at depths just below 3000m.

The reservoir contains 42° API oil with a GOR of 428 scf/stb, 0.33 cp viscosity, a bubble point pressure of 1,930 psia compared to the initial reservoir pressure of 5,634 psia at 3,139 m TVDSS.

The field has been unitised and started production in September 2007 from two horizontal subsea producers. A water injector was added in March/April 2008. The wells are tied back to the Ula platform (Operator BP) located 34 km away in the Norwegian sector of the North Sea.

Water production started in April 2011 and has increased to 47% water cut.

Production uptime averaged 71% on but improved to 97% in April 2014. There have been reliability issues identified with the type of subsea tree that is installed on the Blane wells and the operator is currently investigating what remediation actions may be required.

In April 2014 the field produced an average of 6,676 bpd oil+NGL and 0.4 MMscf/d gas sales. Cumulative gross sales at 31 January 2014 were 22.1 MMstb oil+NGL and 4.2 Bscf of gas.

Enoch is a low relief anticlinal structure straddling the UK-Norway median line in the southern part of the South Viking Graben. Water depth is approximately 120 m.

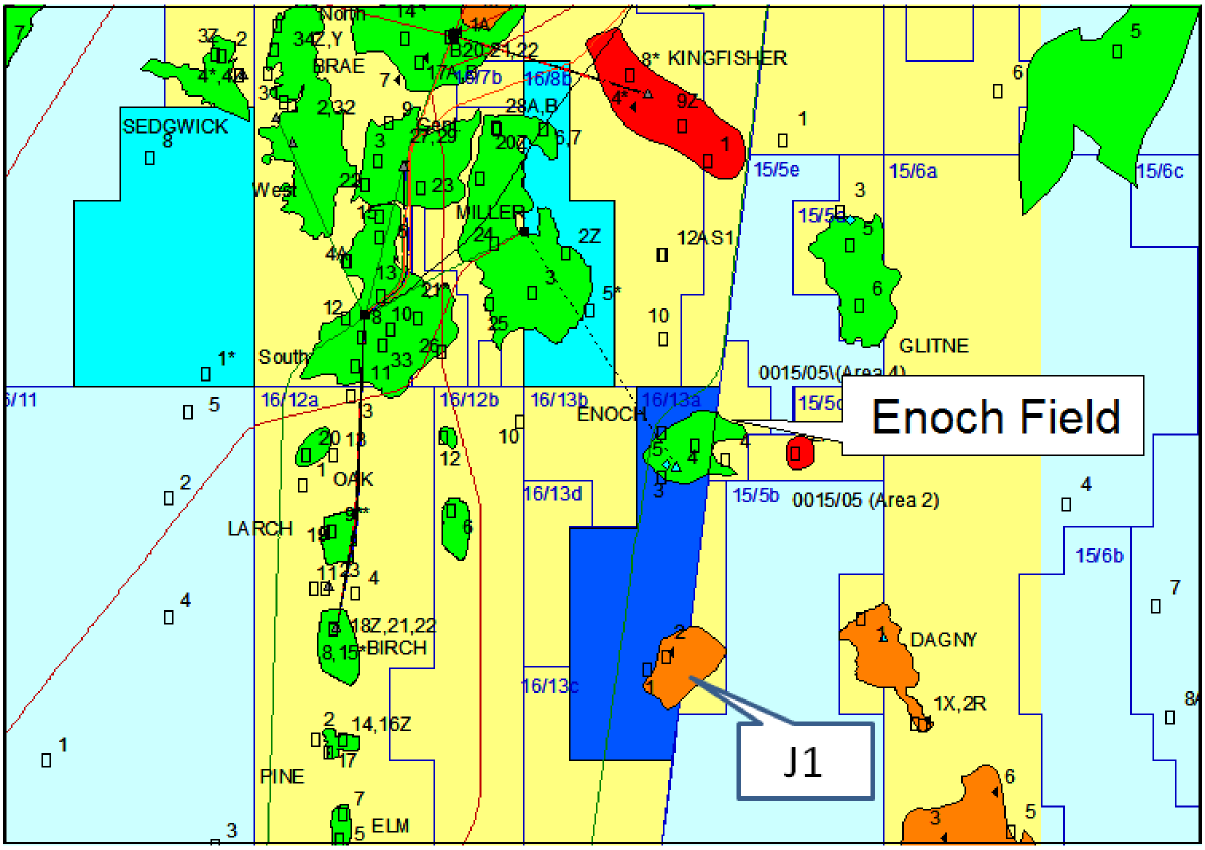

Figure 5-2 Location Map - Enoch Field and J1 discovery

The field was discovered by UKCS well 16/13a-3, drilled by Britoil in 1985, which encountered oil in the Flugga Sandstone Member of the Paleocene/Eocene Sele Formation. Approximately 100 ft of highly porous net sands were logged with a top at 6,887 ft TVDSS. A DST across the interval 6973-7,014 ft MD (6,891-6,996 ft TVDSS) produced 5.9 Mstb/d of 38o API oil but a DST in a lower zone at 7,040-7,050 ft mD (6,958-6,968 ft TVDSS) produced only water. The field extent is defined by five wells: 16/13a–3, 16/13a–4 and 16/13a–5 on the UK side and 15/5–2 and 15/5 –4 on the Norwegian side.

The field was unitised with a UK/Norwegian equity split of 80%/20% which is now fixed. It is operated by Talisman UK Ltd. There are no plans for further development of the field.

Enoch started production to the Brae-A platform from the single horizontal development well, 16/13a-7 on 31 May 2007. The early oil production rate was around 10 Mstb/d and at end-2011 had declined to around 2.2 Mstb/d. Gas lift was initiated in January 2008.

Enoch Field has been shut-in since January 2012 due to the failure of the subsea tree. The field is a single well subsea tied back to the Brae-A platform Operated by Marathon. The subsea tree was removed in 2013 but replacement has been delayed by weather and the estimated production start-up is June 2014.

The integrity of the 15km, 8" carbon steel pipeline to Brae is also a concern. The Operator has concluded that operations can resume with effective corrosion inhibition for a limited period, after which an internal inspection is required.

5.2. BLANE AND ENOCH PRODUCTION AND COST FORECAST

RISC has reviewed Roc's 2P production and cost forecasts and considers them to be reasonable and consistent with RISC's 1 January 2014 reserves estimate. An infill well is under consideration for drilling Q3 2015 and classified as a Contingent Resource.

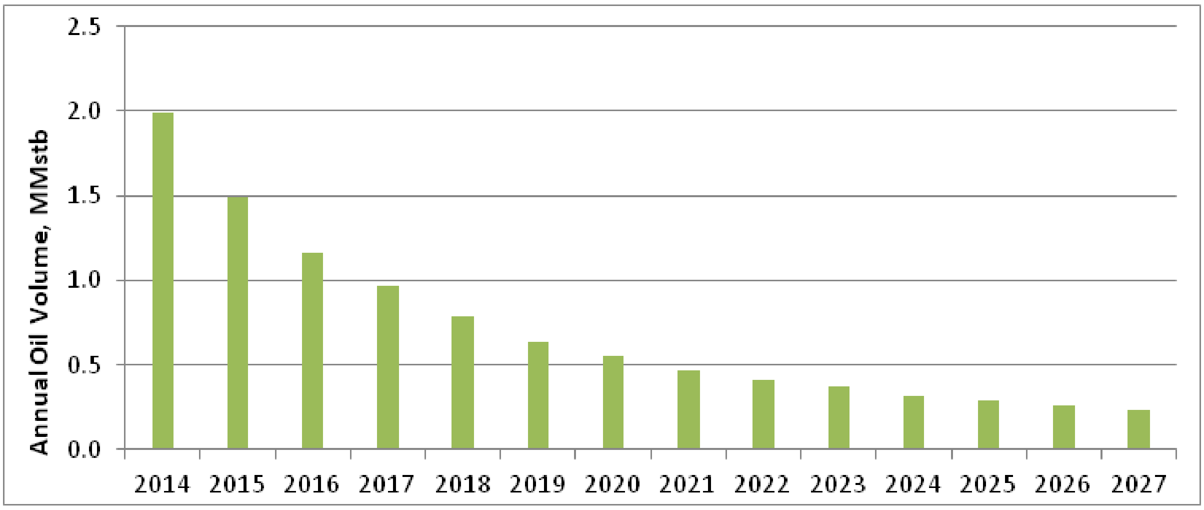

Figure 5-3 Gross 2P Oil Production Forecast - Blane

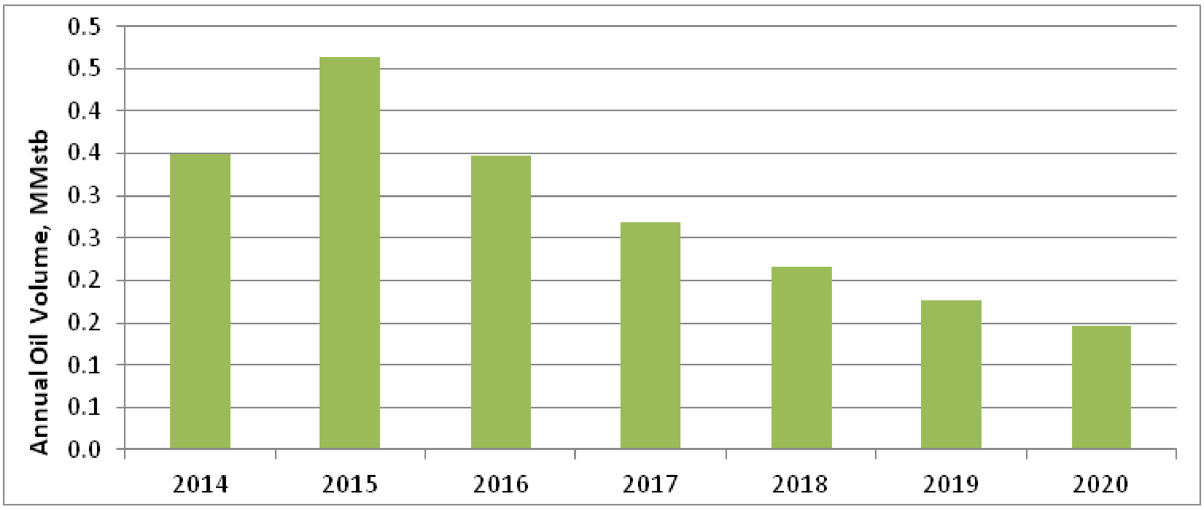

Figure 5-4 Gross 2P Production Forecast - Enoch

The Blane production forecasts assume no further development activities, therefore capital expenditure beyond 2013 is small. No capital costs are included in the 2014 budget, although previous years have had US$3-4 million for specific minor projects. We think it is prudent to allow US$0.8 million per annum until 2023 for minor Blane projects and associated project management.

Fixed base operating costs in 2014 are estimated to be US$9.1 million. However, there is also provision for scale squeezes and subsea tree maintenance in 2014 and every fourth year costing an additional US$6.4 million due to the ongoing issues experienced in these areas.

A significant proportion of operating costs are variable related to tariffs for use of the Ula platform (including processing, gas lift and water injection), transportation through the Ekofisk and Norpipe pipelines and processing and storage at the Teeside terminal. Figure 5-5 shows Roc's total gross 2P operating cost estimate for Blane.

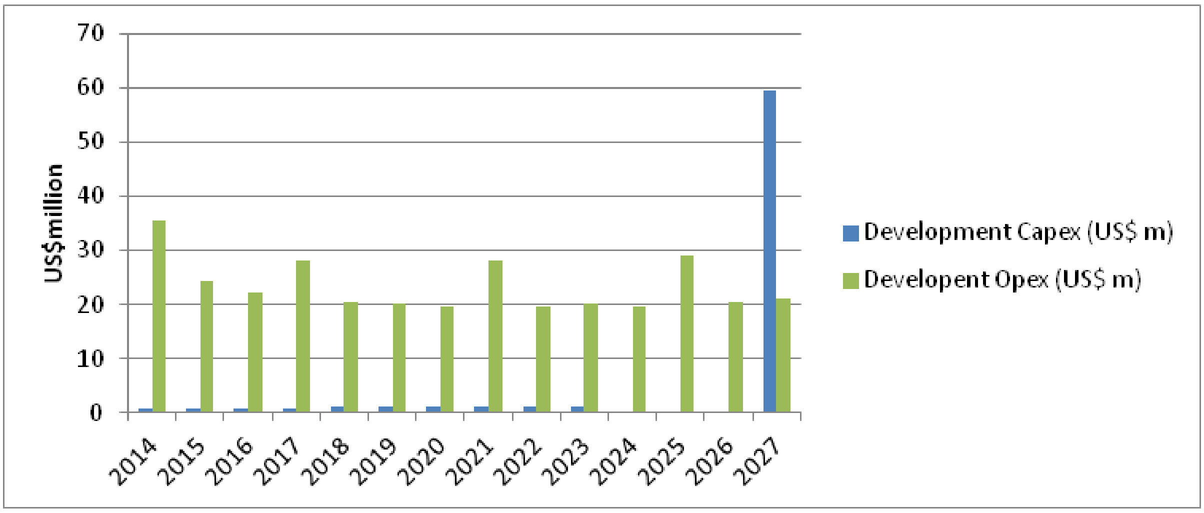

Figure 5-5 Gross Operating Cost Forecast - Blane

US$41 million (RT2014) has been allowed for abandonment of the Blane infrastructure in 2027/2028.

For Enoch, delays to the subsea tree replacement is estimated to have increase the AFE cost of £33.7 to £48.6 million, with £43.6 million spent as of March 2014. Following the subsea tree repair we anticipate minimal capital costs of less than US$0.8 million p.a. going forward associated with minor projects.

RISC estimates direct operating costs (excluding tariffs) of £1.3 million p.a. beyond 2014 with progressive reductions towards the end of field life. The majority of operating costs are related to costs associated with the host and export infrastructure - the Brae pipeline, platform (including gas and liquids processing, gas flare and gas lift) and Forties Production System pipeline tariff. The previous agreement regarding these tariff's has lapsed and a new agreement is currently being negotiated. The operator of the Brae field's (Marathon) has proposed new tariff's that range from unchanged for gas handling costs and pipeline costs up to 10 times increase for water handling costs. Currently the Enoch JV are in negotiations regarding this issue. We have assumed an increase tariff in adopting a mid point range from the previous tariff to the current proposal.

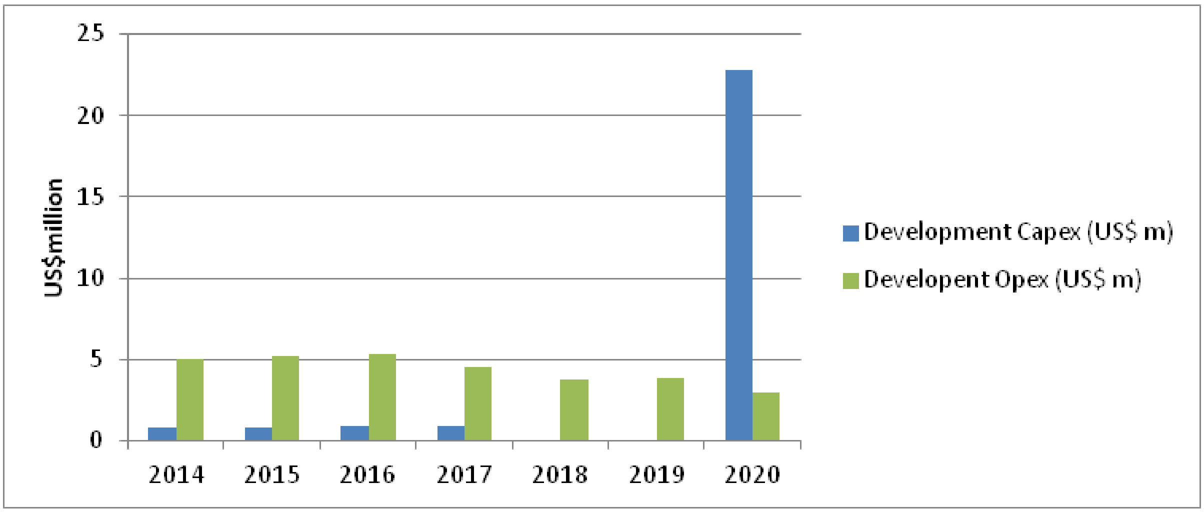

Figure 5-6 Gross Operating Cost Forecast - Enoch

US$19.5 million (RT2014) has been allowed for abandonment of the Enoch infrastructure in 2021.

5.3. RESERVES AND CONTINGENT RESOURCES

The Blane and Enoch reserves estimates are shown in Table 5-1.

	1P	2P	3P
Blane Gas Reserves Bcf	0.4	0.7	1.2
Blane Oil + NGL Reserves MMstb	5.8	10.0	17.1
Enoch Oil Reserves MMstb	1.3	2.0	2.6

Table 5-1 Gross Reserves as at 1 January 2014 - Blane and Enoch

For Blane, from the period 1 January 2014 to 31 March 2014 there has been a further depletion of 426,038 bbl and 14.6 MMscf gross due to production. Cumulative production for Enoch to 31 December 2013 is 8.3 MMstb gross.

In addition, contingent resources have been identified (Table 5-2). The Blane infill well will target the crest of the structure and the current 'reference concept' is a sidetrack which could occur in 2015 with first production starting November 2015. Wells costs are estimated at about £60 million (100%). The project is currently in the operator's 'Select Phase' pending an investment decision later this year. With respect to life extension, there are no firm plans for these activities and we consider the value to be small.

	2C MMstb
Blane Field Life Extension	0.9
Infill Well	4.9
Total Blane	**5.8**
Enoch extended field life	0.5
Total	**6.3**

Table 5-2 Gross 2C Contingent Resources at 1 January 2014 - Blane and Enoch

5.4. J1 DISCOVERY - BLOCK 16/13E (15% ROC)

The J1 gas condensate accumulation in Block 16/13e was discovered in 1984 by well 16/13a-2z (Figure 5-7). Resources are classified as contingent as there are no firm plans for development.

The well encountered gas bearing sands in the Hugin formation. The field is dip-closed to the west, north and south, but fault bounded to the east. It is mapped to straddle the UK/Norway border with an estimated GIIP split of 75% UK and 25% Norway. RISC has not had access to the seismic data and cannot independently verify the field mapping or this split, but it appears plausible based on an inspection of the Enterprise(Oil, 2002) report.

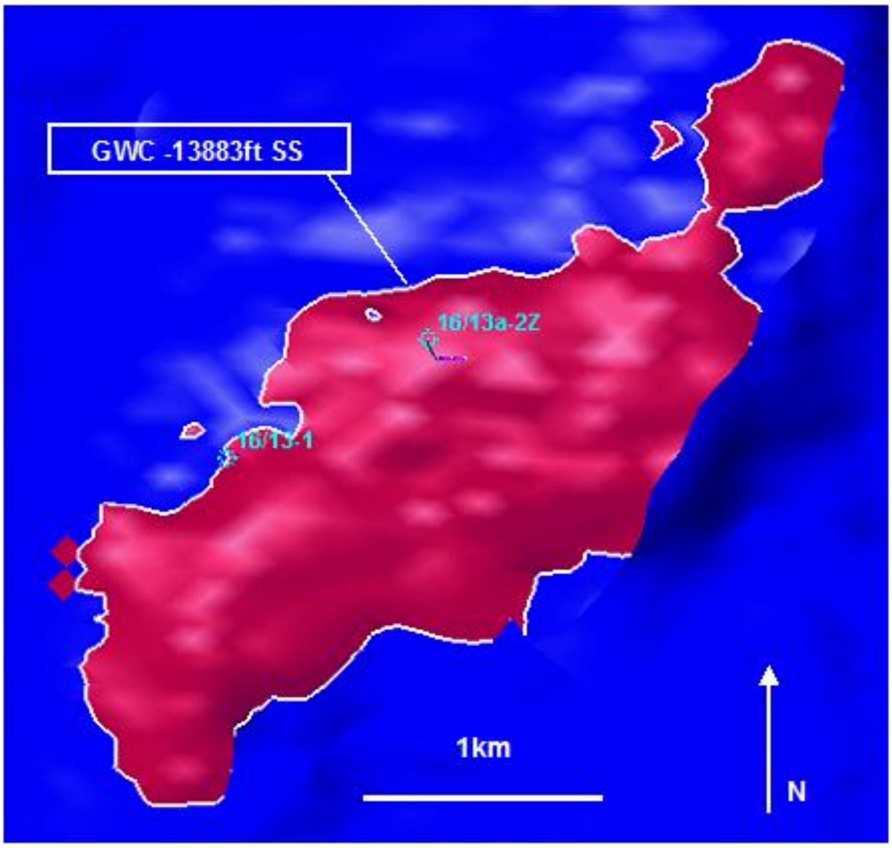

Figure 5-7 Field Outline - J1

Reservoir quality is good, with 98 ft net pay from a gross section of 127 ft. The well intersected a gas water contact at –13,883ft SS. Two DST's were performed and flowed 31 MMscf/d gas with 2,337 stb/d condensate and at 22 MMscf/d with 1,707 stb/d condensate. The well 16/13-1 encountered an oil-charged 5ft thick sand of Ryazanian age, which was tested and flowed a low gravity oil of 22-26 degrees API at a rate of 0.22 Mstb/d. RISC has reviewed the well test data, field evaluation and independently estimated the contingent resources shown in Table 5-3.

	2C
Gas (bcf)	50
Condensate (MMstb)	1.0

Table 5-3 2C Gross Contingent Resources Estimate at 1 January 2014 - 16/13e J1

J1 development via a tie back to the Miller platform was initially suggested. However, the Miller field ceased production in 2007 and is in the process of being decommissioned. The Brae platform is an alternative host but has limited remaining life.

RISC estimate a low probability of development given the limited resource, lack of opportunity and activity to progress a development. Therefore, RISC assigns no value to this small 1984 discovery.

5.5. EXPLORATION

No further exploration potential has been identified

6. NEW ZEALAND

6.1. MAARI/MANAIA/MANGEHEWA

6.1.1. Field Description

The Maari and Manaia fields are located in PMP 38160 offshore New Zealand (shown in Figure 6-1), in which Horizon Oil holds a 10% interest. The fields are operated by OMV New Zealand Limited (OMV).

Production commenced in February 2009 and averaged 9000 stb/d in March 2014 from 6 production wells.

Figure 6-1 Maari and Manaia Field Location

Oil is produced via a well head platform to the FPSO Raroa in a water depth of approximately 100m. Following a refurbishment of the FPSO mooring and turret system in 2013, a major new project called the Maari Growth Project is underway. This project comprises:

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

A structural section showing the location of significant reservoirs is shown in Figure 6-2.

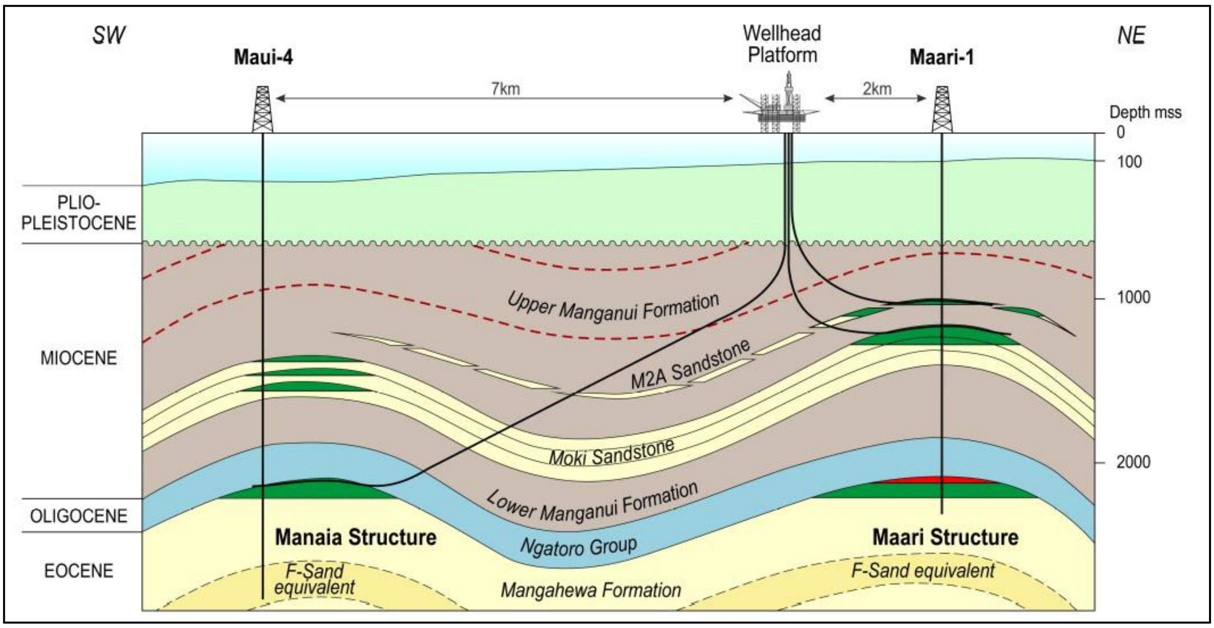

Figure 6-2 Maari Manaia Structural Section (from Horizon)

The Maari Field currently produces from the Moki and M2A sands, both of 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 Manaia field.

A deviated well from the Maari platform has been drilled to the Mangahewa Formation of the Manaia field and is currently producing. There is further potential for oil in the Manaia Moki Formation; oil shows were observed during the drilling of the Maui-4 discovery well and further significant shows were intersected in the recent Manaia-2 appraisal well. The evaluation of these results is not yet complete and no resource has been assigned to this reservoir.

The Maari Field is covered by 3D seismic data acquired by Shell Todd in 1999. The data has been reprocessed several times, most recently in 2009 and is of fair quality, but has an area of poor data and a push-down underneath a gas cloud over the central part of the field, shown in Figure 2.3 below. The Operator (OMV) has acquired a new seismic survey over the field which is presently being reprocessed. It is expected that this will improve definition and aid in delineation well and development well locations and also lower the range on resource and reserve estimates.

The Moki reservoir provides the bulk of the production. The Operator's structure map at the Top Moki reservoir (Figure 6-3) is considered well-defined due mainly to the amount of well penetrations. The wells drilled to date have not encountered large depth issues. Faulting in this reservoir is minor.

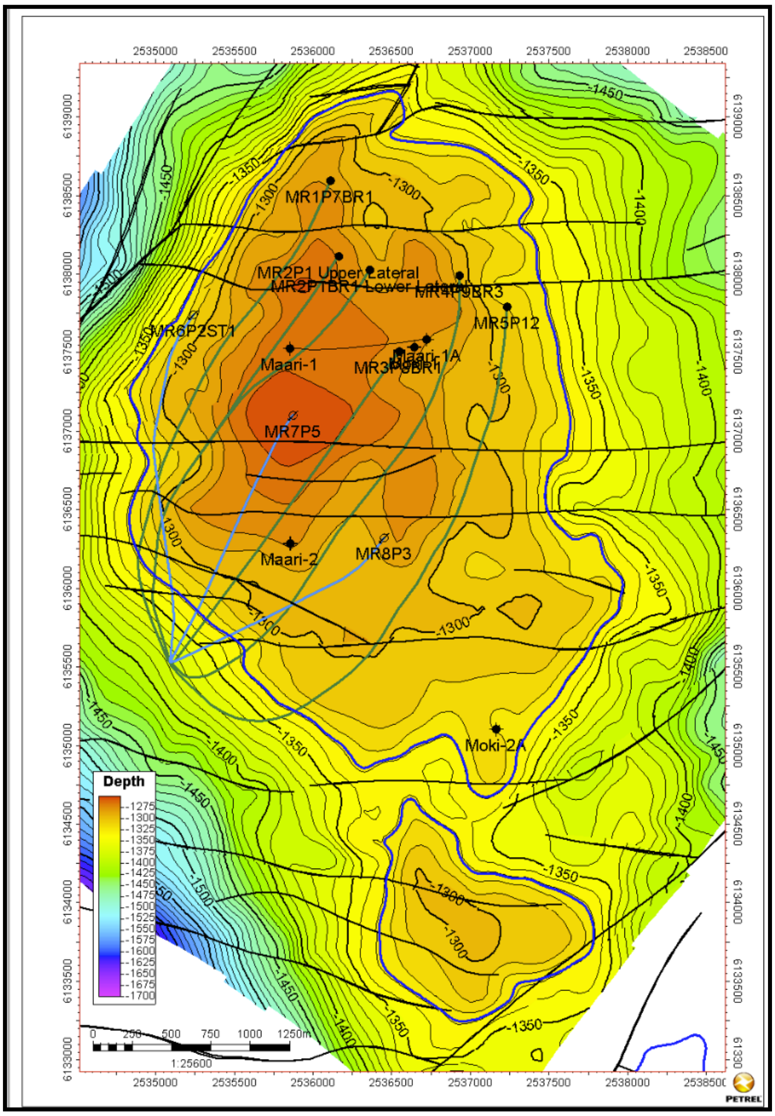

Figure 6-3 Maari Moki Depth Map

The Moki and M2A sands are deepwater turbidites deposited during the Miocene downwarping of the Taranaki Basin. The Moki contains seven fining-upwards depositional cycles of which the lower cycles are easily correlatable. However, the upper cycles display more lateral variation in deposition, possibly due to channel migration over subtle sea floor depth variations. The Maari Moki oil column is contained within the upper two cycles (separated by a thin shale).

The M2A sands appear to be a distal basin floor fan and are thinner and possibly less areally continuous than the Moki sands.

The deeper Mangahewa sands of the Kapuni Group were deposited in the post-rift thermal sag phase in the Eocene. The Mangahewa sands are fluvial in origin, leading to significant areal variations in reservoir quality.

RISC has estimated STOIIP ranges for the Maari and Manaia accumulations reservoir shown in Table 6-1.

Reservoir	Low	Best	High
Maari Moki STOIIP (MMbbl)	115	163	223
Maari M2a	21	27	34
Maari Mangehewa	9	14	20
Manaia Mangehewa	22	32	47

Table 6-1 Maari and Manaia Field STOIIP Estimates

Reserves are shown in Table 6-2. These are based on RISC's estimates as at 30 June 2013 updated for production.

Field	Reserves (MMstb)		
	1P	2P	3P
Maari	30.3	55.2	93.3
Manaia	2.4	4.3	7.2
Total	32.7	59.5	100.5

Table 6-2 Gross Reserves as at 1 January 2014 - Maari and Manaia Fields

Cumulative production to 31 December 2013 is 22.69 MMstb gross. From the period 1 January 2014 to 31 March 2014 there has been a further depletion of 883,000 bbl gross due to production.

RISC has also estimated a further 0.9 MMstb of contingent resources attributable for water injection on the Maari M2A reservoir (Table 6-3). We are not aware of any plans to progress this project.

Reservoir	2C (MMstb)
Maari M2A Water Injection	0.9

Table 6-3 Gross 2C Contingent Resources as at 1 January, 2014 - Maari M2A

6.1.2. Production and Cost Forecast

RISC has reviewed and accepts the profile used by Horizon for the 2P production forecast for the Maari and Manaia fields which is consistent with our reserves estimates. OMV provided a short-term production forecast to account for planned downtime for maintenance and operations which has been incorporated. From 2015 onward, Horizon's 2P forecast reverts to the RISC Year-End 2013 2P forecast (Figure 6-4). Production is truncated in 2030, however there is still significant tail production beyond this period. There are no gas sales/reserves.

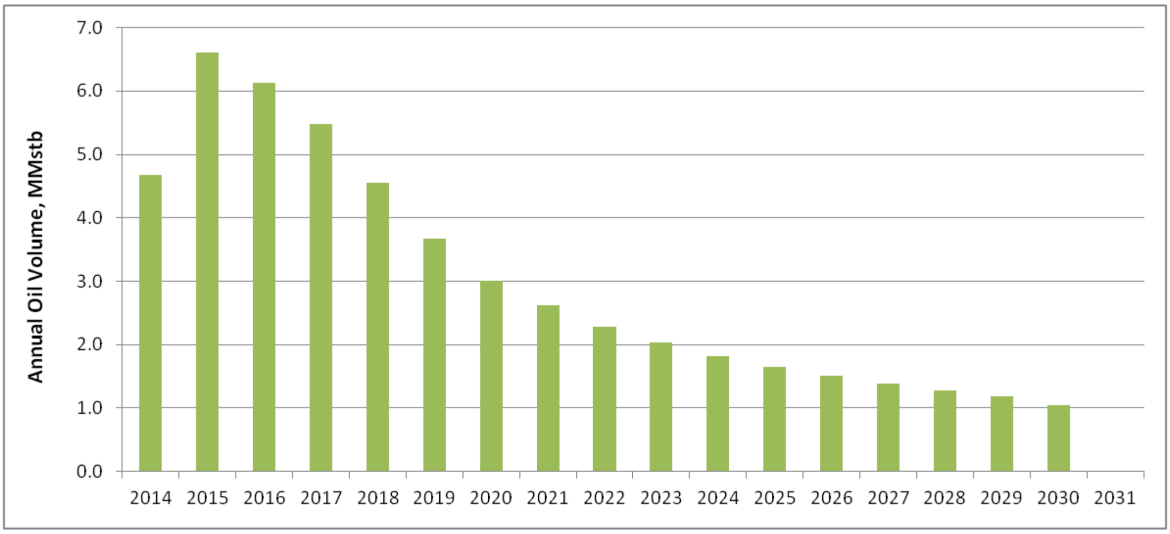

Figure 6-4 Gross 2P Oil Production Forecast - Maari and Manaia

Also considered is a 2P case with no benefit from the water injection at the Maari Moki field. This is a downside case where the water injection fails to boost oil production. Other than the Maari Moki upper reservoir, the rest of the production forecast is the same as the 2P case above. The net impact is 6.9 MMbbl over the forecast period.

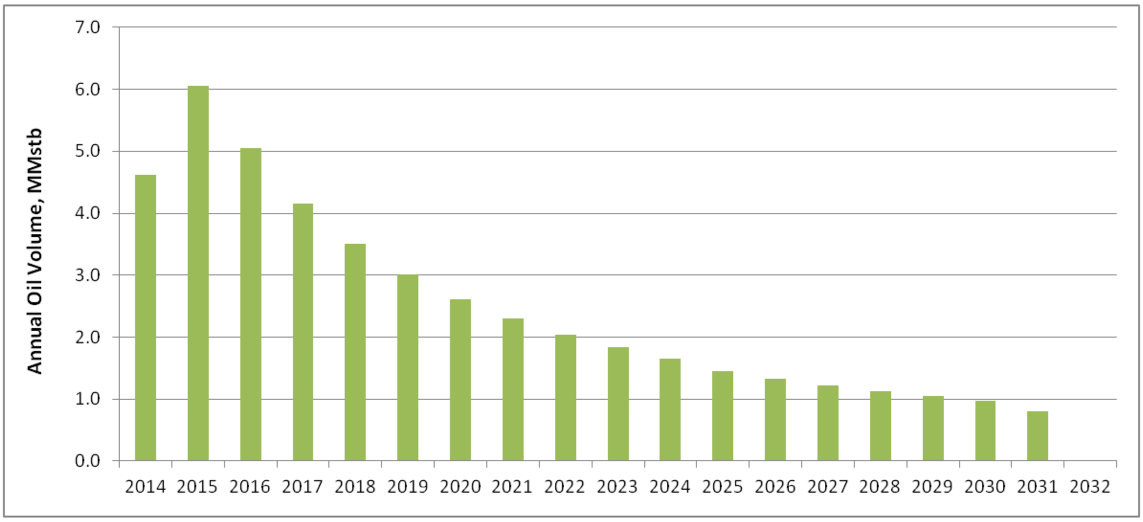

Table 6-4 Gross Oil Production Forecast - No Benefit from Water Injection at Maari Moki Upper

RISC has reviewed and accepted the cost profiles provided by Horizon in their economic model.

The Maari-Manaia development involves a not-normally manned wellhead platform housing the wellheads of the five production and three water injection wells, linked via subsea flowlines to the floating production, storage and offloading vessel ('FPSO') Raroa, anchored 1.5 km away. The production wells are lifted with downhole Electrical Submersible Pumps (ESPs). Because the ESPs need regular replacement, a workover rig is kept on the platform. Water is injected to maintain reservoir pressure.

Total gross capital costs consistent with the production forecast are anticipated to be NZ$341m (million) over the period 2014-16 (US$27m net to Horizon). RISC has categorised capital costs into development wells, major repairs/upgrade and appraisal.

Appraisal costs of NZ$42m were budgeted in 2014 for a Manaia appraisal well that was recently completed.

Development well costs of approximately NZ$280m are budgeted for 2 infill producers (Maari Deep, Maari Full field), 2 sidetracks (Moki Cycle 1 & Cycle 2) and 1 new well + recompletion for water injection.

The remaining capital costs are NZ$18m for the remaining capitalised FPSO lease, recompletions and 'Running the Business' costs.

Capital cost forecast 2014-16 is shown in Figure 6-5 below. Note these costs exclude any exploration activities. Abandonment costs are estimated at $70 million.

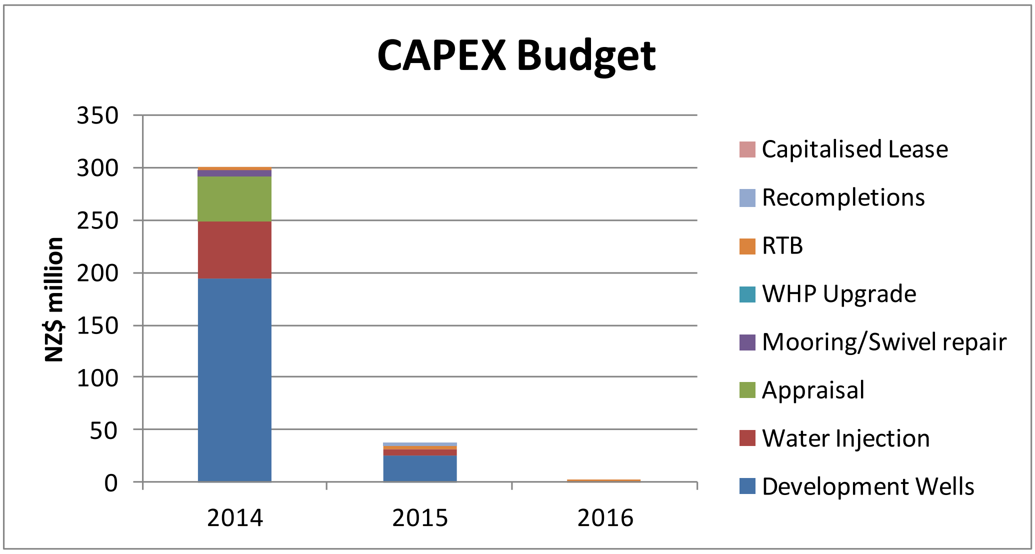

Figure 6-5 Gross Capital Budget - Maari and Manaia Fields

After 2014 the Operator forecasts operating costs (opex) to increase slightly before falling as production declines.

The major component of opex is the Operating fee, which is approximately NZ$42m in 2014. This is a largely contracted amount and therefore carries relatively little uncertainty.

The element of operating costs with the highest uncertainty is workover costs for ESP changeouts. The budget forecasts ESP workover costs of NZ$11-14m pa, reflecting an assumption of 3 workovers per year.

The operating cost budget to 2023, extrapolated to 2031 is shown in Figure 6-6 below. The exchange rate used was 0.8.

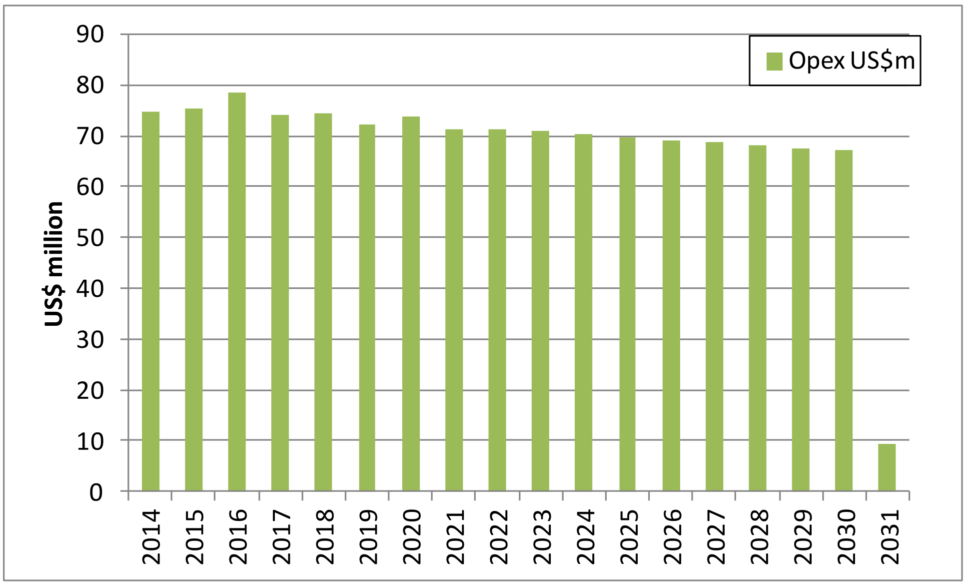

Figure 6-6 Gross Operating Cost Budget - Maari and Manaia Fields

6.2. EXPLORATION

Exploration potential exists in the Whio Prospect. This is a separate structure at both Moki and M2A reservoir level with further potential in the Mangahewa and deeper Farewell, Kaimiro and North Cape reservoirs.

OMV will be drilling this well as a farm-in, reducing Horizons interest from 21% to 10% to match the Maari and Manaia Fields in the event of a commercial discovery. Drilling is scheduled to commence in June 2014 at a budget cost of approximately $40 million gross.

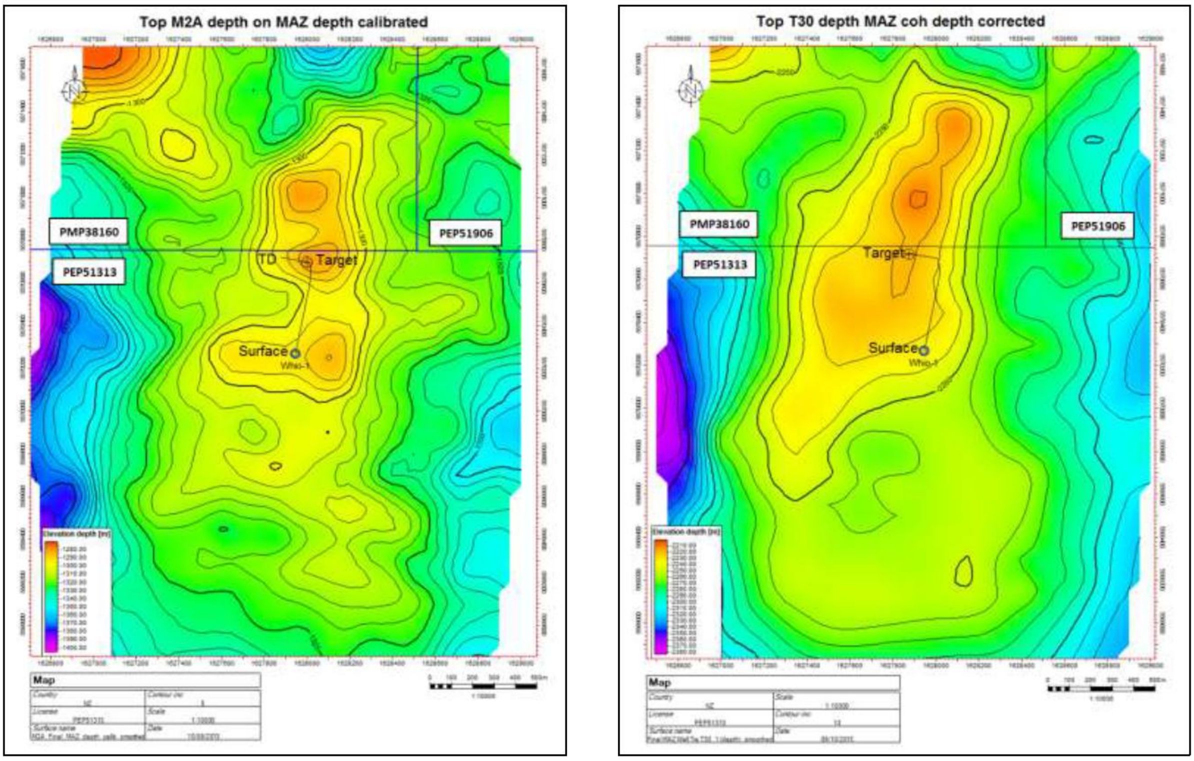

Figure 6-7 Whio Prospect M2A and Moki Depth Maps

The operator OMV calculates best estimate prospective resources of 15 MMbbl in the M2A, Moki and Mangahewa reservoirs.

These resource ranges have been checked by RISC and are considered reasonable.

If successful, Whio could be developed using a satellite well head platform, linked back to the Maari FPSO.

Gas volumes are significant, and we have assumed the gas is used for fuel or flared.

In the success case, Whio can be developed using 4 deviated wells, tied back to Maari field.

An initial rate of 15,000 bopd was based on initial rates from the analogue wells in the existing development. Gas volumes of 20 Bcf are assumed used for fuel, or flared.

The Mid Case production forecast for Maari 2P reserves plus Whio is shown below.

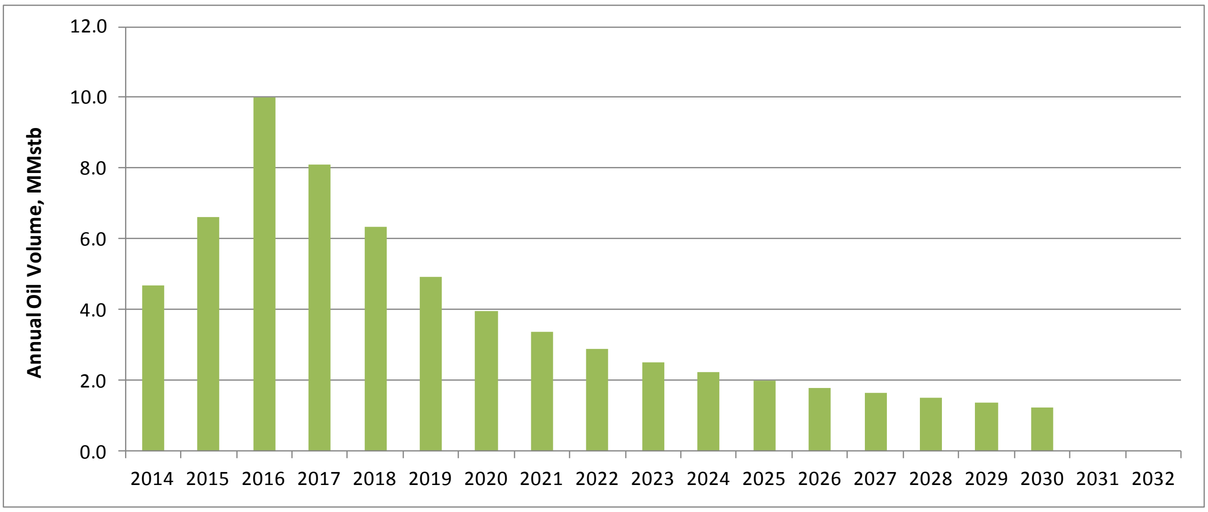

Figure 6-8 Maari 2P + Best Estimate Gross Production Forecast - Whio Prospect

The development is assumed to begin in mid 2014 with the drilling of an exploration well at a cost of US$40 million (fully carried). It is assumed that if the exploration well is successful the development could be approved in 2016. The construction, installation and tieback (via subsea pipeline to Maari WHP) of a new well head platform will occur in 2017 and 2018 and is forecast to cost US$100 million. The drilling of 4 horizontal development wells in 2018 is estimated to cost US$200 million ($50 million per well).

Fixed operating costs of US$14 million p.a. have been estimated based on support for an unmanned WHP and workovers every three years for the producing wells. Variable operating costs of $1/bbl are included. Abandonment is estimated to cost US$50 million for the development.

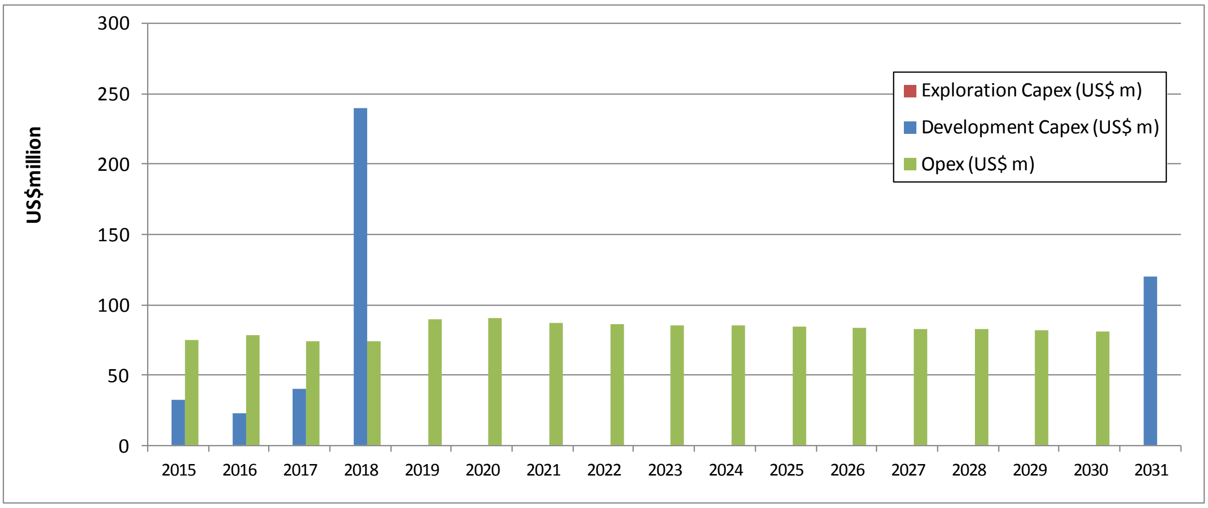

Figure 6-9 Gross Capex and Opex - Whio Prospect

In the low and mid cases, the permit value is based on the farmout terms with OMV in which OMV pays Horizon's 21% share ($8.4 million) to earn an 11% interest. This represents a promote of 1.9 valuing Horizon's interest at $7.6 million.

In the case of an unsuccessful well, the transfer of interest does not occur, we have assumed that for the high case the farmout could be duplicated valuing the interest at $15.2 million.

The EMV calculations indicate a value of $13.0 million for Horizon's 10% share which is comparable to the high case valuation.

7. CHINA PROPERTIES

7.1. BEIBU GULF

Roc’s and Horizon's interests are contained in the Beibu Gulf Area A and B. Roc holds a 19.60% interest and Horizon a 26.95% interest in the development and production assets. Interests in the exploration and appraisal phase are Roc 40% and Horizon 55%. The producing fields are WZ6-12 North, WZ6-12 South, WZ12-8 West and the non-producing fields WZ12-8 East and WZ 12-3 (Figure 7-1). The development and production assets are operated by CNOOC (51%). Upon declaration of commerciality of a development project, CNOOC has the right to back in for 51% and assume operatorship which has been exercised in the development and production assets to date.

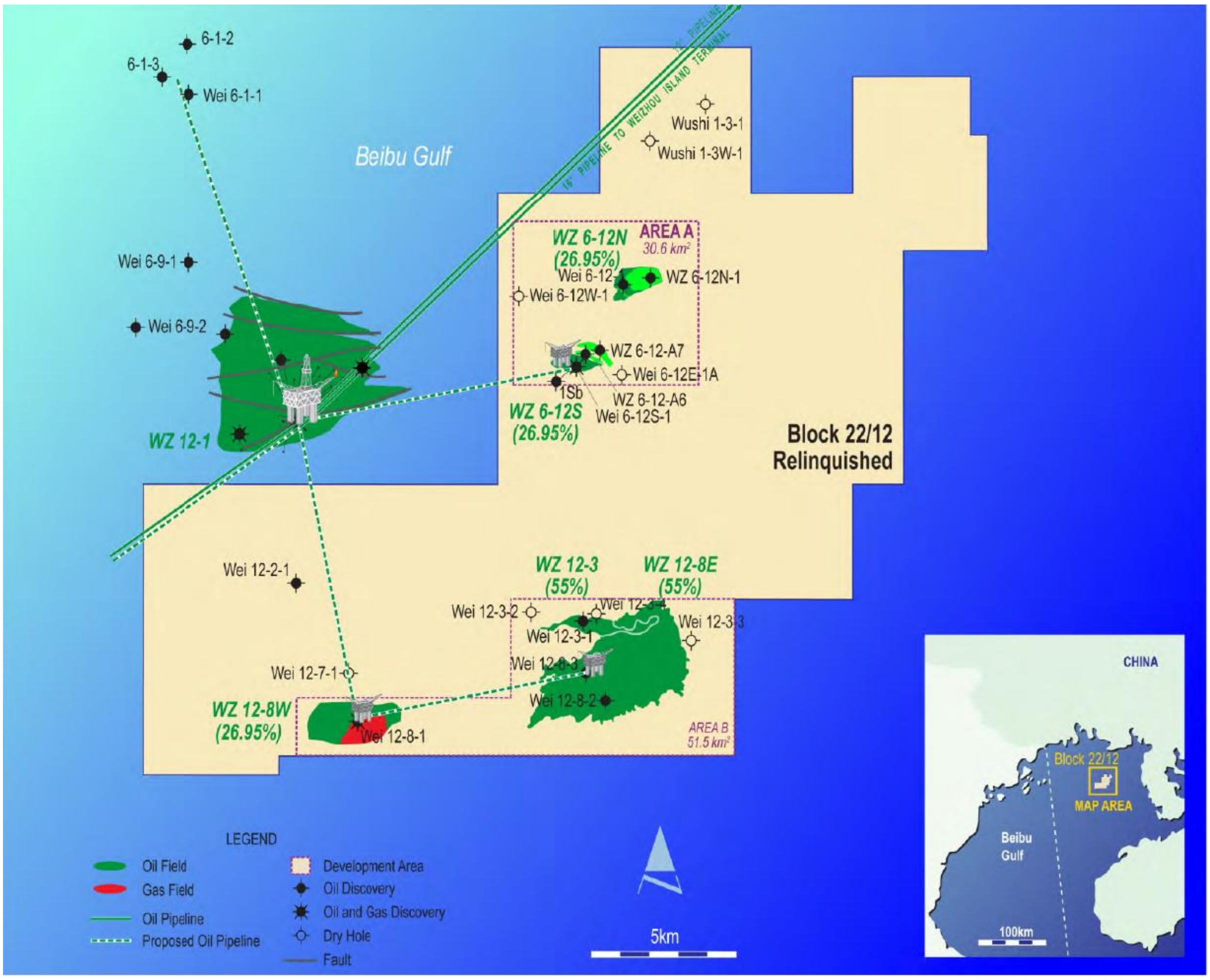

Figure 7-1 Location Map – Beibu Block 22-12

The Wei 6-12 oil field was discovered in 2002. An appraisal well on the Wei 12-8 East oil field drilled in 2004 confirmed the presence of oil but indicated that the oil was viscous so commercial development would not be straightforward. In 2006, the drilling of the Wei 6-12S-1 exploration well made a significant oil discovery which was appraised by four wells.

Following the formal end to the exploration period for Block 22/12 on 30 September 2008, the WZ6-12, WZ6-12 South and WZ12-8 West oil fields were declared development areas.

In 2010 CNOOC elected to participate for its full 51% share in the development, reducing Roc's and Horizon's share to 19.60% an 26.95% respectively. The Overall Development Plan (ODP) was completed in 2010 and following final CNOOC approval in January 2011 the joint venture proceeded to its Final Investment Decision in February 2011. CNOOC assumed operatorship of the project in 2Q11 and a CNOOC operating subsidiary company (Weizhou Operating Company) was established.

The Beibu Gulf development project was completed in 2013. Beibu first oil commenced in March 2013 with production reaching forecast rates. The development incorporates two remote wellhead platforms and one joint processing platform, which are connected by bridge to the CNOOC WZ 12-1A platform complex and utilise existing water injection and gas processing facilities.

The initial development phase targeting the WZ 6-12 North and South & Sliver Fields and the WZ 12-8 West Field is complete with 15 wells on production. Ten development wells were drilled from the WZ 6-12 platform and five development wells from the WZ 12-8 platform.

The two undeveloped oil accumulations in the retained development areas are WZ 12-8 East and WZ 12-3. Development feasibility studies are in progress.

7.1.1. Field Description

Oil contained in the fields is reservoired in Eocene-aged fluvial-lacustrine sandstones of the Luishagang Formation, Miocene-aged Jiaowei shallow marine sandstones and the Oligocene-aged Weizhou sandstones. Oil quality varies from light to heavy quality, low to high viscosity, with some waxy crude.

RISC has reviewed the reservoir mapping, geological modelling and volumetrics carried out by Roc and considers them to be reasonable. Roc's estimate of STOIIP, reserves and contingent resources are shown in Table 7-1 and Table 7-2. RISC has estimated the 12-8E contingent resources (Table 7-3).

Field	STOIIP (MMstb)		
	Low	Best	High
WZ 6-12 North	25.8	30.5	36.2
WZ 6-12 South and Sliver Block	23.2	28.0	30.3
WZ 12-8 West	19.5	26.2	27.7
W 12-8 East (incl. 12-3)	68.5	84.7	94.2
Total	137.0	169.4	188.4

Table 7-1 Discovered STOIIP as at 1 January 2014 - Beibu Gulf

<table>
<tr><th rowspan="2">Field</th><th colspan="2">Reserves (MMstb)</th></tr>
<tr><th>1P</th><th>2P</th></tr>
<tr><td>WZ 6-12 South and Sliver Block</td><td>7.1</td><td>8.9</td></tr>
<tr><td>WZ 6-12 North</td><td>8.7</td><td>10.1</td></tr>
<tr><td>WZ 12-8 West</td><td>4.1</td><td>5.4</td></tr>
<tr><td>Total</td><td>19.9</td><td>24.4</td></tr>
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Table 7-2 Gross Reserves as at 1 January 2014 - Beibu Gulf

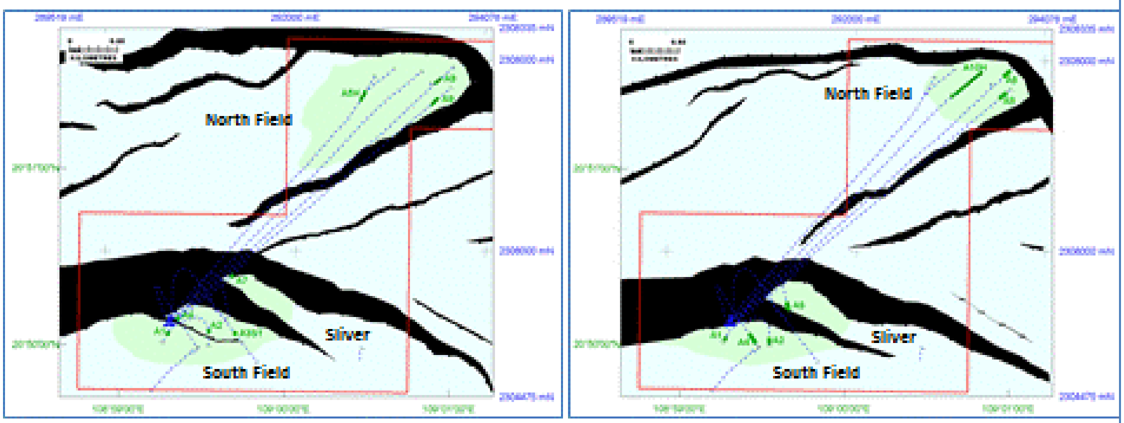
Contingent Resources	2C (MMstb)
WZ 12-8 East (incl. 12-3)	11.5

Table 7-3 Gross 2C Contingent Resources as at 1 January 2014 - WZ12-8E RISC Estimate

Cumulative production to 31 December 2014 was 3.0 MMstb. From the period 1 January 2014 to 31 March 2014 there has been a further depletion of 1.2 MMbbl gross due to production.

WZ12-6-12 North Field

The field consists of stacked pay in the T30, T31 and T32 units. WZ 6-12-1 discovered the WZ 6-12 North Field in March 2002. The trap is a fault sealed structure with dip closure to the west, Figure 7-2. The well intersected 13.5 m of excellent quality net oil pay in the Weizhou T31C sand but was not tested. The follow up WZ 6-12N-1 vertical exploration well in October 2012 intersected 9.5 m of gross oil pay in the T31C and 33.7 m of gross oil pay in the T32L. Also 13.5 m of gross oil pay was intersected in the shallower T30D sand.



6-12 T31C Schematic

6-12 T32L Schematic

Figure 7-2 Well locations and schematic North, South and "Sliver" Block Field Areas

WZ12-6-12 South Field and "Sliver "Block

The WZ 6-12S discovery was made in May 2006, approximately 3 km southwest of well WZ 6-12-1. The WZ 6-12S-1 well, discovered over 70 m of net pay, mainly oil, in multiple sands of the Weizhou Formation. Gas was found in two thin sands. The trap is a hanging wall rollover structure, approximately 2 km long and 1 km wide, against an arcuate east-west trending fault, Figure 7-2. Faulting has created two structural provinces within the field that have been named "South Block" and "Sliver" Block".

Adjacent to but not part of the interpreted WZ 6-12 South Field lies a separate interpreted fault related high which is designated the "Sliver" Block This prospect was matured by the Foreign JV for exploration drilling via a well drilled from the WZ 6-12 Wellhead Platform (WZ 6-12-A7).

Well WZ 6-12A-6 intersected oil pay in the T30D and T31U in the South area and in the T 32L in the "Sliver" area. The hydrocarbon type within the T30 A is uncertain and the T30B is gas bearing. The T31C is thin and is interpreted to be fault affected.

Well WZ 6-12-A7 intersected oil pay in the T31C and T32U sands in the northern part of the "Sliver" Block. The upper sands (T30 to T31U) were faulted out at this location, as were the T32 L sands. The T31C sand with 6 m of gross oil-bearing sand is interpreted to be in reservoir continuity with the thin T31C sand intersected in well WZ 6-12E-1A. Brightening of T31C seismic amplitudes downdip of the A-7 well suggests the presence of thicker reservoir development. WZ 6-12-A7 intersected 26.5m of gross sand and 2.3 m of net oil pay in the T32U sand. A limited MDT run (restricted by hole condition) was conducted in A7 with sampling of one zone.

Figure 7-3 is a well cross section showing the correlation and continuity of reservoir units within the South Field and Figure 7-3 is a schematic cross section showing the structural relationship between the South Field, "Sliver Block" and North Field.

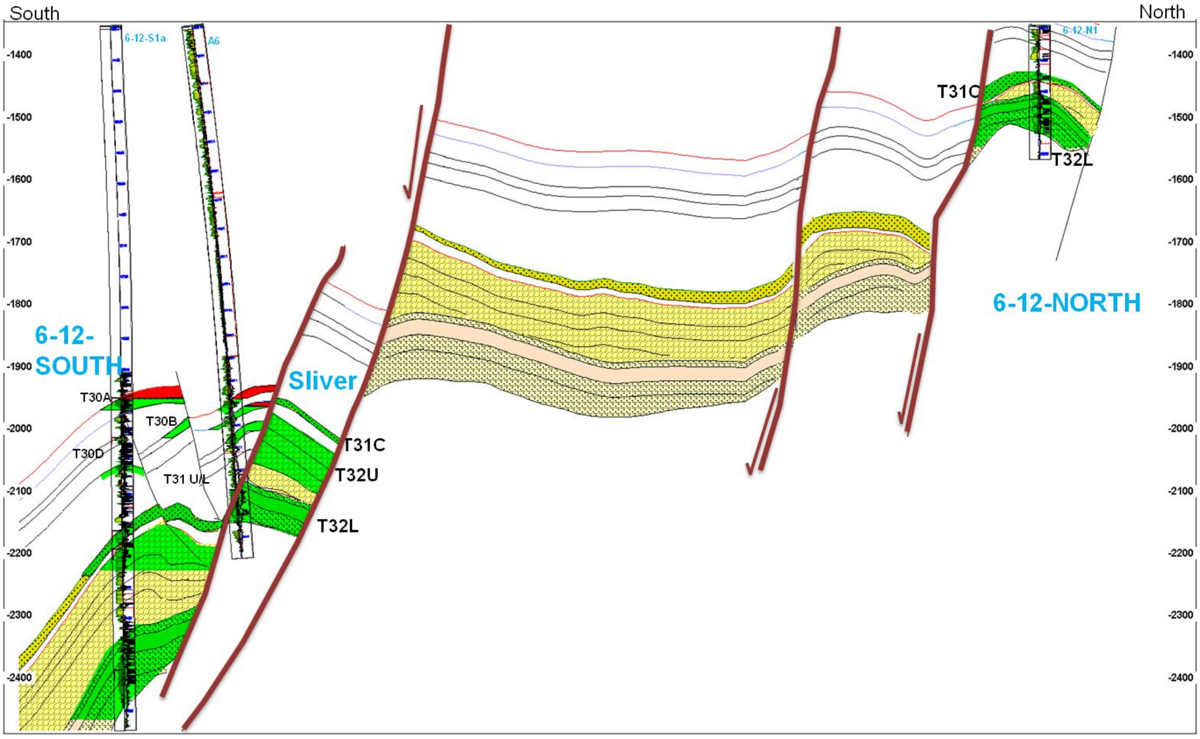


Figure 7-3 Structural relationship of WZ 6-12 South, "Sliver" and North Fields

Roc has estimated initial OOIP using the Petrosys mapping software (at 1P, 2P and 3P levels of confidence) and Petrel 3D geological modelling software (2P only). RISC has reviewed Roc's Petrel

RE model which is based on a single geological realization using a stochastic distribution of properties and is satisfied that the model represents a reasonable "most likely" realization of the subsurface geology.

WZ12-8 West

The WZ 12-8 West field was discovered by the WZ 12-8-1 well drilled in 1993. The well encountered a 12 m net oil column and a 2 m overlaying gas column within the Jiaowei Formation. Four DSTs were run and a series of RFT sampling and measurements were conducted. The well free flowed 1300 barrels per day of 21 degree API oil with 2.1 MMscf/d of gas on test.

Development drilling was undertaken during 2013. This programme included an initial pilot hole, WZ 12-8-A1P, which penetrated the entire reservoir sequence and acquired conventional core over the lower portion of the J2 reservoir. Subsequently five horizontal reservoir sections were drilled in an east to west direction.

Confidence in the latest mapping is provided by the seismic amplitude anomaly shown as yellow to red colour fill in Figure 7-4 which generally conforms closely to the structural limits of the oil pool (the green polygon marks the depth of the OWC at -953 mTVDss and the red polygon marks the GOC at -943.5 mTVDss). These amplitudes continue to the east and are interpreted by Roc to identify a continuing migration route from west to east. RISC notes that anomalous amplitudes can be caused by lithology variation and tuning effects (reservoir thinning) in addition to hydrocarbon saturation.

The only fault of any significance for the J2 reservoir is the southern boundary fault. No internal faults of any significance are mapped and production compartmentalisation caused by faulting is not anticipated.

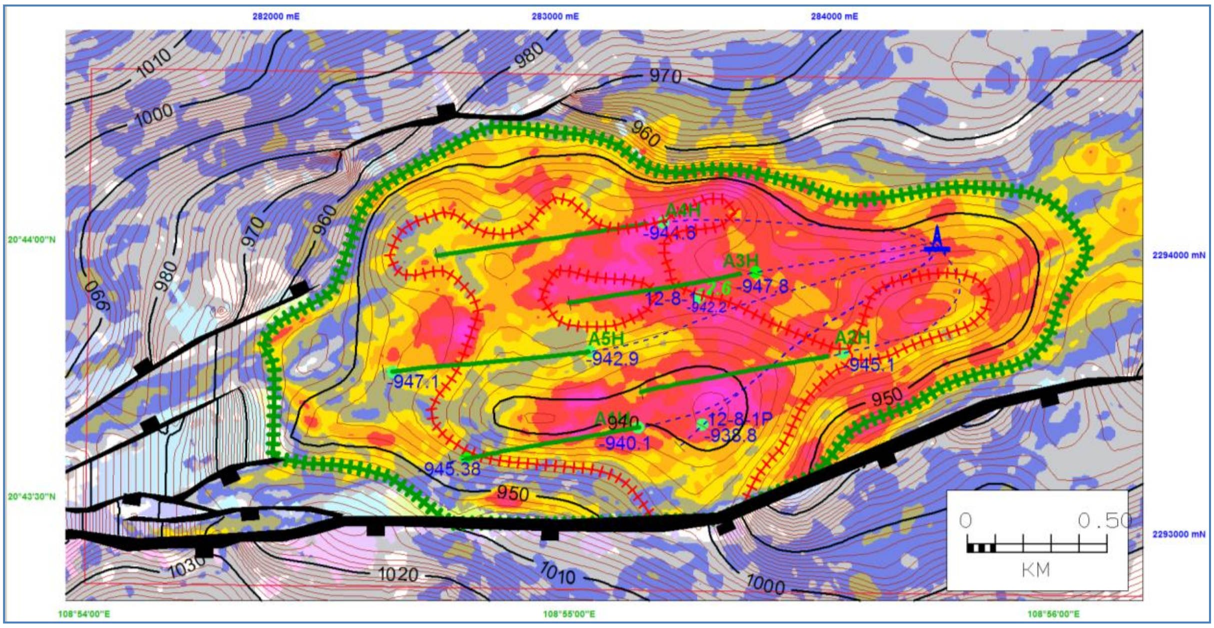


Figure 7-4 Final well tied top J2 reservoir depth structure map (post development drilling)

WZ12-8 East (incl 12-3)

The WZ12-8 East Weizhou oil accumulation was discovered in 1982 by Wei 12-3-1. The well was a combined structural test of the Middle Miocence Jiaowei Formation and stratigraphic test of an interpreted lower Weizhou Formation pinchout upon Basement. A single 11.5 m oil bearing Weizhou sand was encountered (net oil pay 9.8 m). The Jiaowei sands were encountered water bearing and outside of structural closure.

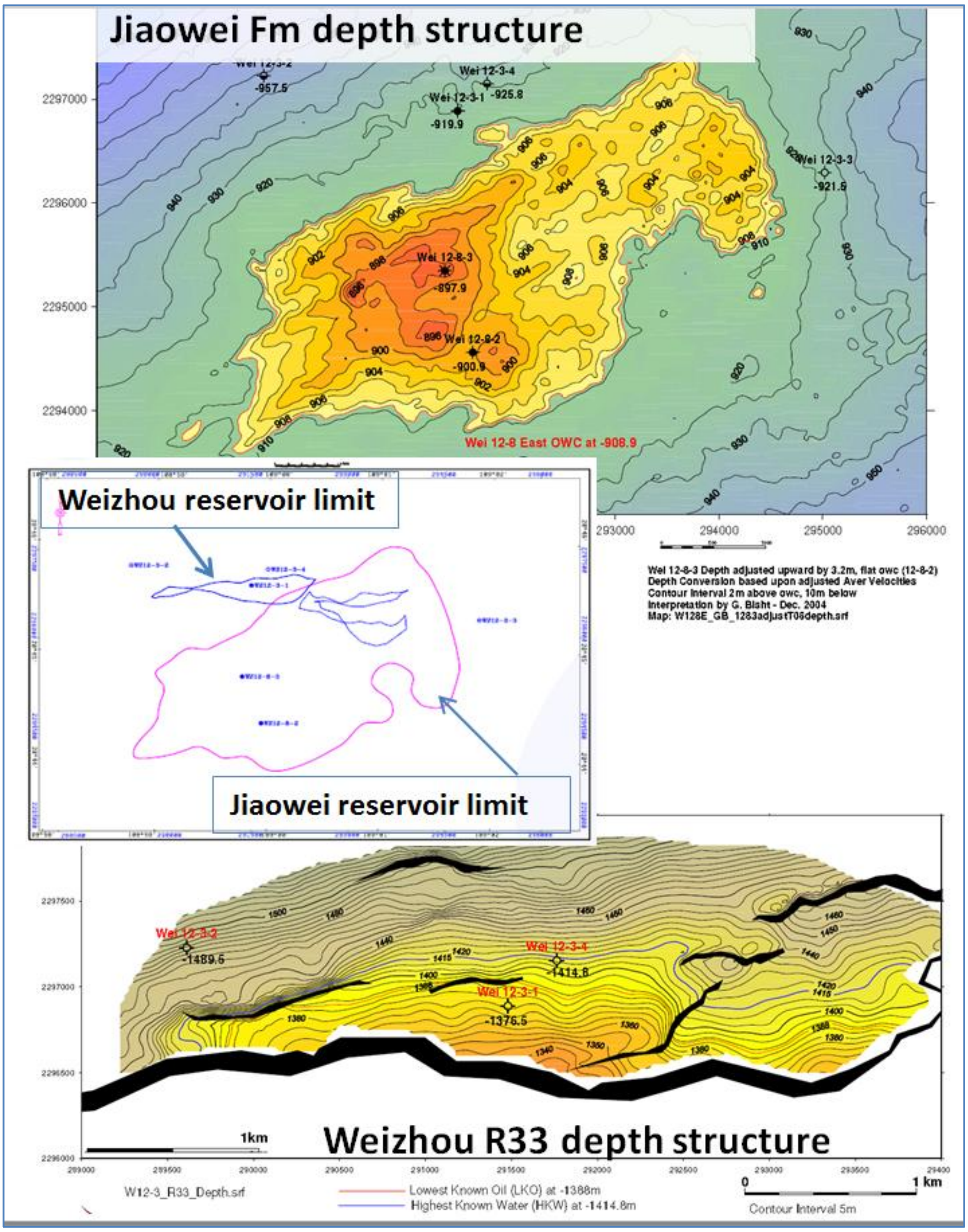


Figure 7-5 WZ12-8 East reservoir depth structure maps and field limits

A drill stem test of this sand flowed oil at a maximum rate of 1380 bopd on a 48/64" choke. The oil contained only minor solution gas at 56 scf/stb. The oil has a gravity range of 32.7 to 33.9 degrees API and a wax content of 18.9 to 22.3%. The pour point is 30 to 32 degrees Celsius. The Wei 12-3-1 crude is very similar in nature and quality to the Weizhou oil under production in the Wei 12-1 oilfield and is characteristic of Eocene Liushagang generated oil. The Weizhou oil is volumetrically small, with a best estimate STOIIP of 3.4 MMstb.

The vast majority of the oil is contained in the Jiaowei reservoir which was discovered in 1994 when the WZ 12-8-2 well intersected an 8 m oil column at a depth of 930.5 m within highly porous and permeable, shallow-water marine sands. The well tested 2295 bopd of 21 degree API oil from the interval 931 – 935 m with artificial lift provided by ESP. Unlike the deeper Weizhou accumulation, the Jaiowei trap is relatively simple and is defined by 3D seismic as a simple, unfaulted four way dip closure, as shown in Figure 7-5 (upper map).

7.1.2. Production and Cost Forecasts

Roc has based the 2P production forecast on the RISC Year End 2013 2P reserves forecast. We have reviewed this and agree with the forecast. 2P oil production and related cost for Beibu WZ6-12 North, South and 12-8 West are shown below.

As WZ 6-12 and 12-8W fields are already developed, capital costs from 1 Jan 2014 will be minor. There are US$3m each for 6-12 and 12-8W in 2016 for minor upgrade works.

The Operator forecasts operating costs to plateau are approximately US$50m p.a. in the early years of production. Initially approximately 50% of operating costs are tariffs for processing and transportation through CNOOC owned facilities, though this declines as production declines. Fixed costs are approximately US$20m pa and up to US$10m pa is allowed for workovers to change out the ESPs. We are in agreement with the operating costs in Roc's economic model.

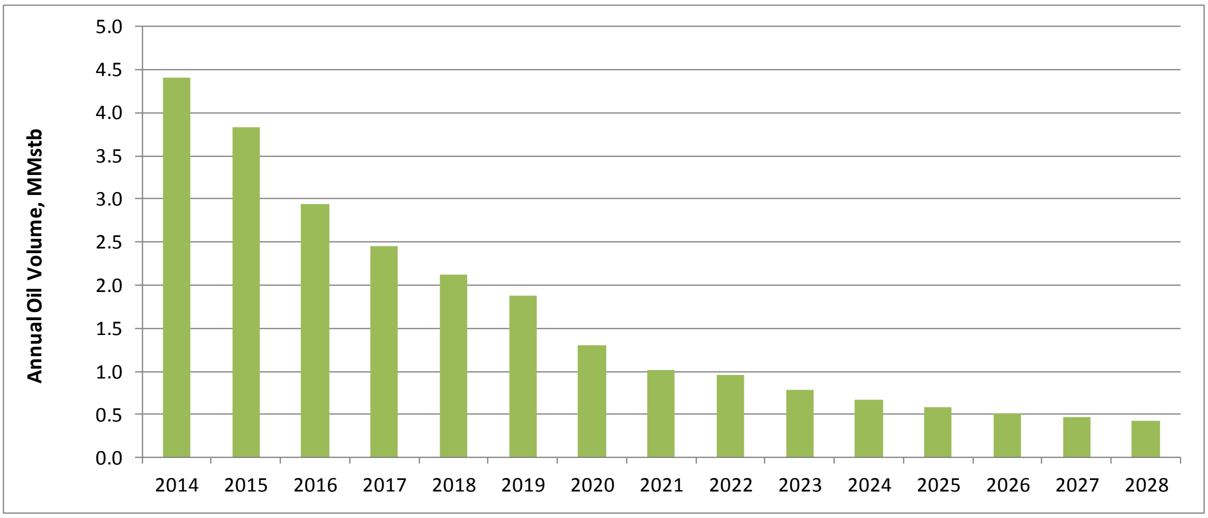


Figure 7-6 Gross 2P Oil Production Forecast - Beibu WZ6-12 N, 6-12 S and 12-8 W

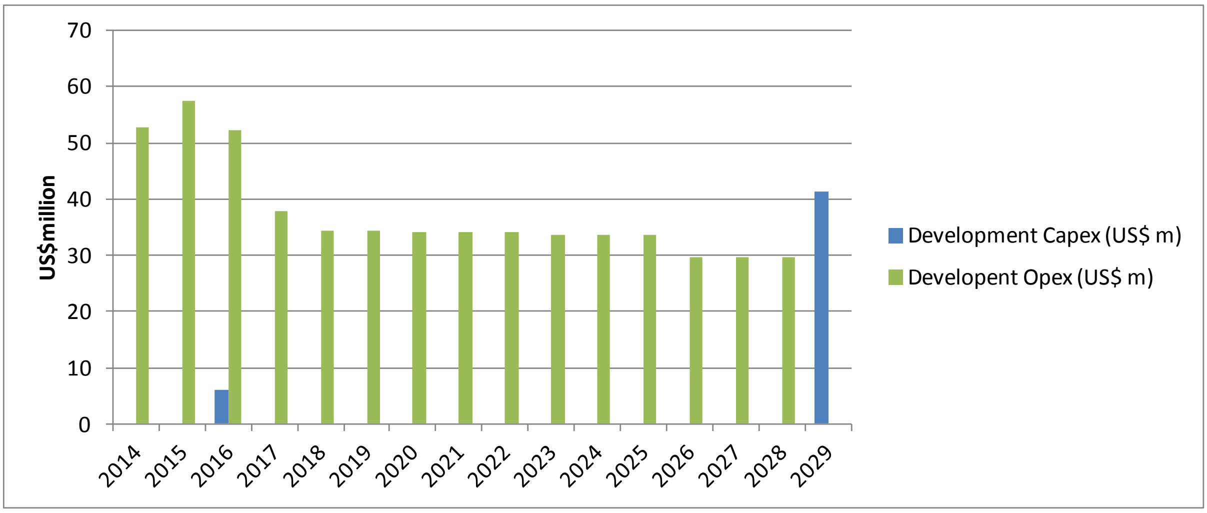


Table 7-4 Gross 2P Cost Forecast - Beibu WZ6-12, 6-12 S and 12-8 W

7.1.3. 12-8 East Proposed Development

The development plan is under study by CNOOC. RISC has reviewed the results of CNOOC's reservoir simulation studies and considers them to be reasonable and in line with analogue fields. The current JV concept is a phased development of 4 initial wells that include elements of appraisal followed by 3 wells based on results. The concept targets 5.4 MMstb of Contingent Resources. We have adjusted development plan and forecasts to be in line with Roc's STOIIP estimates which is a potentially larger development. We have prepared a development concept based on this larger scheme.

RISC has assumed the Weizhou reservoir to be developed by 1 horizontal well with 13 horizontal wells in the Jiaowei reservoir.

The WZ12-8E development is currently categorised as Contingent Resources. RISC estimates the total oil production over the 20 year forecast period is 11.5 MMstb. Figure 7-7presents the forecast of the combined 2P+2C oil production.

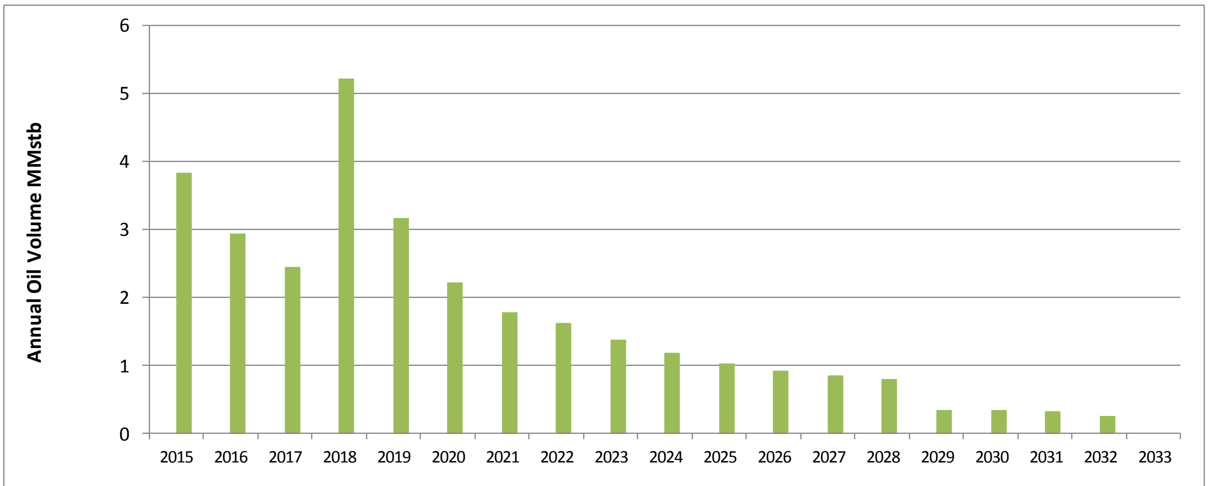


Figure 7-7 Gross 2P+2C Gross Production Forecast – 2P Plus WZ12-8E

It is assumed the development could be approved in 2016. The construction, installation and tieback (via subsea pipeline to WZ-128W WHP) of a new well head platform will occur in 2016 and 2017 and is forecast to cost US$45 million. The drilling of 14 horizontal development wells in 2017 is estimated to cost US$168 million ($12 million per well).

Fixed operating costs of US$24 million p.a. have been estimated based on support for an unmanned WHP and workovers every three years for the producing wells. Variable operating costs according to the Beibu production agreement tariff's are included.

Abandonment is estimated to cost US$38 million for the development. Figure 7-8 presents the cost forecast.

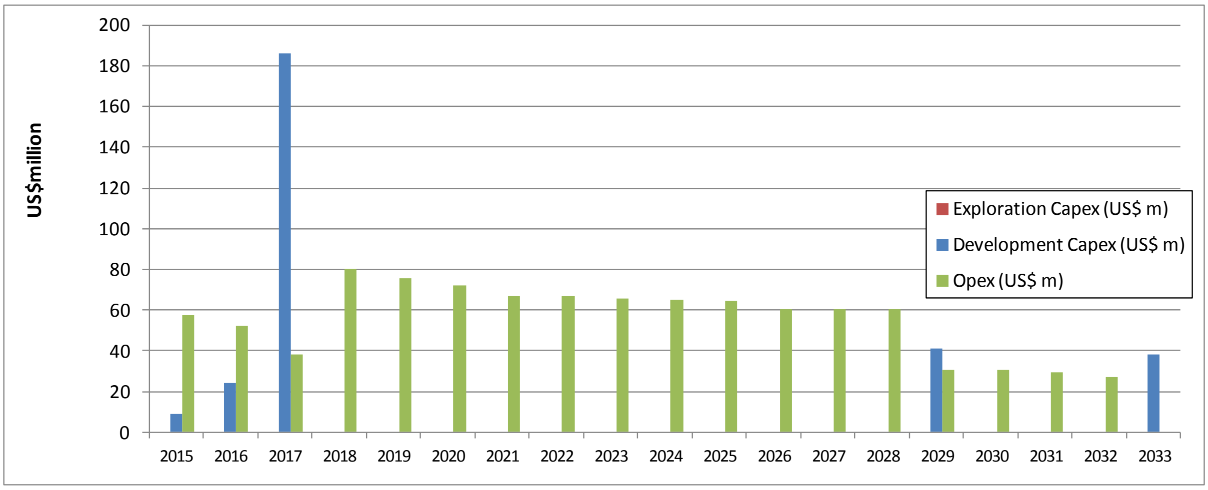


Figure 7-8 2P+2C Cost Forecast – 2P Plus WZ12-8E

7.1.4. Exploration

The joint venture is evaluating the drilling of 2 prospects (Figure 7-9). A well needs to be drilled to retain the exploration interests in the block.

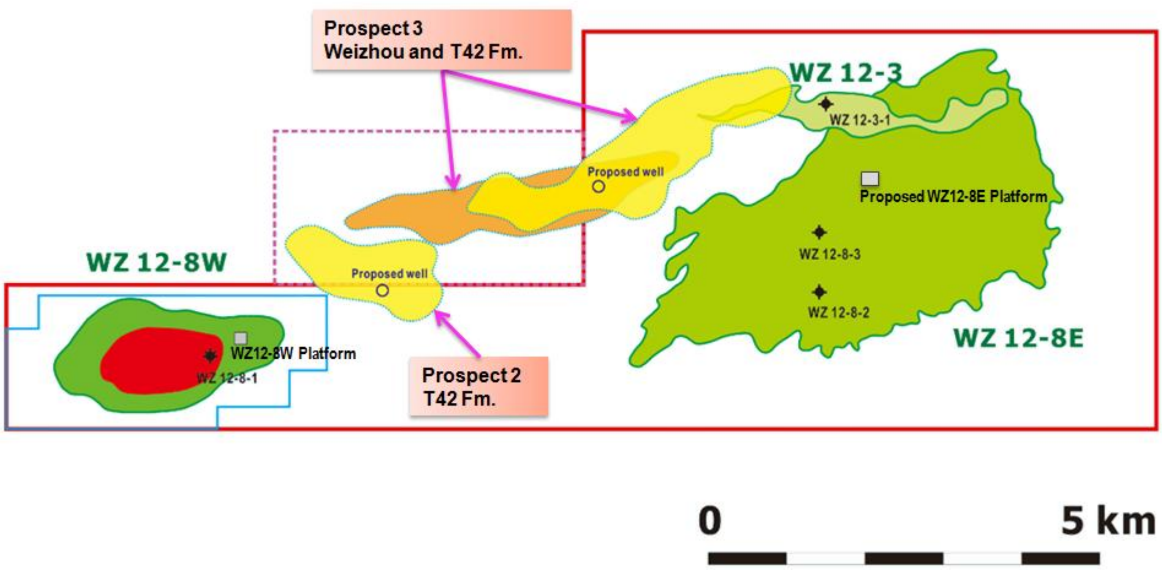


Figure 7-9 Beibu Gulf Exploration Prospects (subject to approval of license boundary extension shown in dotted red line)

Prospect 3 is targeting Weizhou and T42 level sands with an aggregate oil in place estimate of 24 MMstb gross. The main Weizhou has a POS of 32% estimated by Roc. Prospect 2 has mapped potential in-place resources of 6 MMstb at the T42 level and has a POS of 9% estimated by Roc.
RISC has not reviewed the volumetrics and mapping. We have prepared a conceptual development of Prospect 3 for evaluation of potential value. We have estimated prospective resources of 5 MMstb gross for this prospect subject to a license boundary extension.

Prospect-3 Proposed Development

The development of Prospect-3 is assumed to begin in 2015 with the drilling of an exploration well at a cost of US$8 million. This will be followed up with an appraisal well in 2016 if successful at a cost of US$10 million.

It is assumed the development could be approved in 2017. The construction, installation and tieback (via subsea pipeline to WZ-128W WHP) of a new well head platform will occur in 2018 and 2019 and is forecast to cost US$45 million. The drilling of 5 horizontal development wells in 2019 is estimated to cost US$60 million ($12 million per well).

The production forecast for Block 22-12 2P + 2C + Prospect-3 is given below.

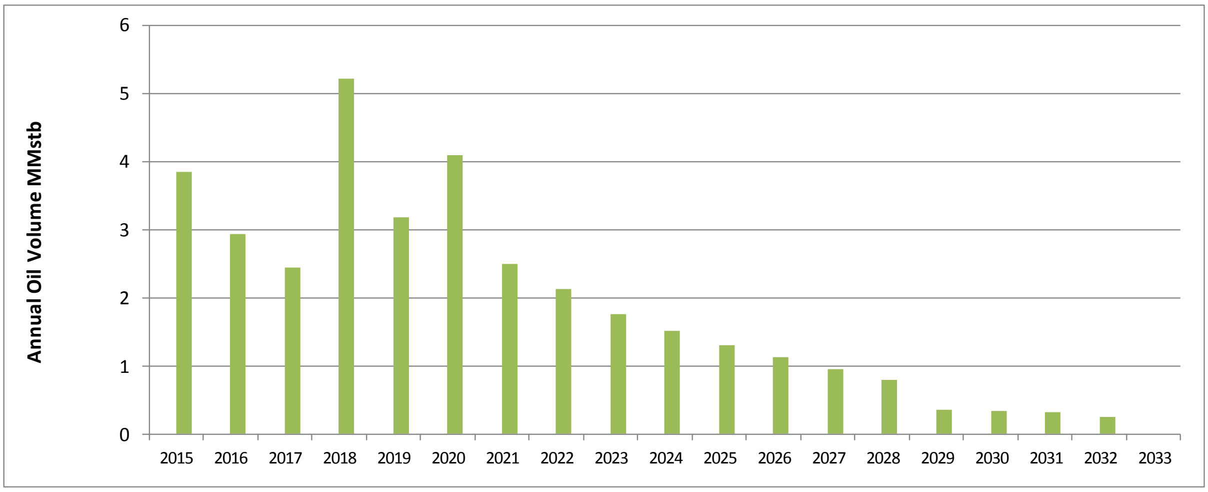


Figure 7-10 Gross Production Forecast: 2P Plus 2C Plus Prospect-3

Fixed operating costs of US$24 million p.a. have been estimated based on support for an unmanned WHP and workovers every three years for the producing wells. Variable operating costs according to the Beibu production agreement tariff's are included.

Abandonment is estimated to cost US$20 million for the development.

Figure 7-11 presents the cost forecast.

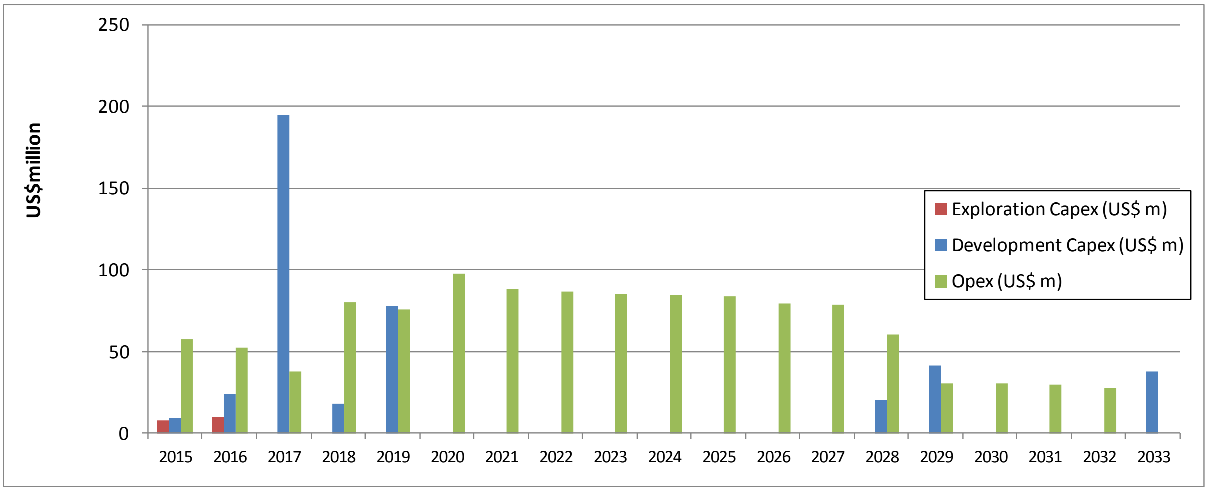


Figure 7-11 Cost Forecast 2P + 2C + Prospect-3

For the mid case valuation, we have assumed that an $8 million exploration well ($4.4 million and $3.2 million net working to interest to Horizon and Roc respectively) could be farmed out on a 2:1 promote. In the high case, we have assumed a 2 well option including Prospect-2. In the low case, we have assumed no farmout premium. The values for each company are summarised in Table 7-5.

Company	Low US$ million	Mid US$ million	High US$ million
Horizon (55%)	0.0	4.4	8.8
Roc (40%)	0.0	3.2	6.4

Table 7-5 Beibu Gulf Exploration Fair Market Value - Net Horizon and Roc Working Interest

7.2. BOHAI BAY

Roc’s interests in the Bohai Bay are in the Zhao Dong Block, Zhanghai and Chenghai Blocks and the exploration block 09/05, Figure 7-12. Roc's interest are as follows:

Zhao Dong Block

- Development interest of 24.5% in the Zhao Dong field development incl. C &D fields
- Unitised interest of 11.667% in C4 field development
- 50% exploration interest

Zhanghai & Chenghai Blocks

- 39.2% interest

Bohai Block 09/05

- 100% interest

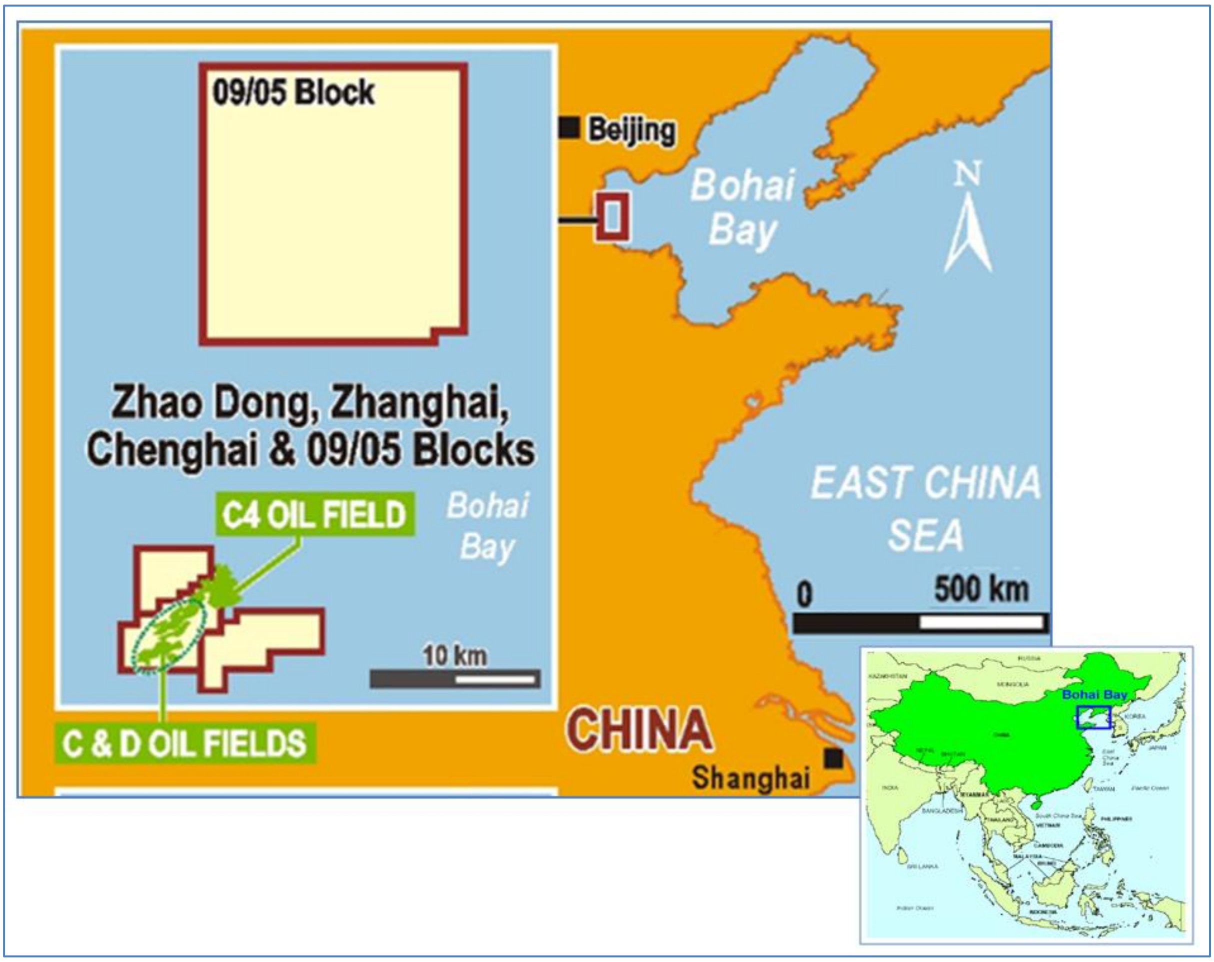


Figure 7-12 Location Map – Bohai Bay

Roc acquired a 24.5% operated interest in the ZD Block in mid-2006 via the acquisition of 100% of the shares of Apache China Corporation LDC. The ZD Block contains the C&D fields which commenced production in 2003 and part of the C4 field. At the time Roc acquired the asset, approximately 20 MMstb of oil had been produced from the C&D fields.

The fields are currently producing and undergoing simultaneous continuous development. Since acquiring the asset, the Roc-led joint venture has drilled over 120 development wells in the block, installed two platforms adjacent to the existing Zhao Dong platforms and installed new facilities at C4. The gross production in March 2014 averaged 16,200 bbl/d of oil and 8.6 MMscf/d of gas (3.2 MMscf/d sales).

In March 2011, the existing Petroleum Contract covering the Zhao Dong Block was modified to include the adjacent Zhanghai and Chenghai Blocks with the aim of commercialising previous near field discoveries in the area and encouraging further exploration activity. Any potential commercial development in the blocks would utilise the existing Zhao Dong facilities. The term of the Zhao Dong Contract and Production Period will be extended when and as necessary to accommodate any new production from the additional blocks.

On 11 May 2012, Roc was awarded a 100% operated interest in the new exploration block 09/05 offshore Bohai, located approximately 15km north of Roc's Zhao Dong block. The minimum work commitment for the first phase of the exploration period includes 3D seismic acquisition and the drilling of exploration wells.

In October 2013, Roc successfully completed the 162km^2 3D ocean bottom cable (OBC) seismic campaign in the 09/05 exploration licence. Seismic processing has commenced and will assist in high grading the prospect inventory, in preparation for commencement of early exploration drilling.

Roc has signed a farmout option agreement with Horizon Oil (Beibu) Limited (HZN). Under the terms of the agreement Horizon will pay 40% of all petroleum exploration costs incurred until the exercise or lapse of the option, which entitles Horizon the right to farm into a 40% working interest in Block 09/05. In advance of spudding the first exploration well Horizon can exercise the option to acquire the 40% interest by paying a 2 for 1 promote on two exploration wells. In light of the proposed merger with Roc, Horizon has elected not to exercise the option.

7.2.1. Field Description

The Bohai Bay is a prolific oil producing province with stacked reservoirs system, ranging in age from Palaeozoic to Tertiary. Reservoir quality is good to excellent. The source rock is rich and generative. The Zhao Dong Block is extremely oil prone and oil is generally found wherever a suitable trap exists. Within the block, 27 different stratigraphic levels are known to contain oil; 16 of these are currently productive. Oil is waxy with a low pour point and a low acid content.

The Zhao Dong C/D Fields and the C-4 Field, (Figure 7-13) comprise a large number - some 150 - separate oil pools, with over 20 different productive reservoir horizons and sands having been shown to contain mobile oil and gas. In many cases, individual pools are segmented by internal faults. As well as drilled fault blocks, there are many undrilled compartments, largely contiguous with the existing drilled areas.

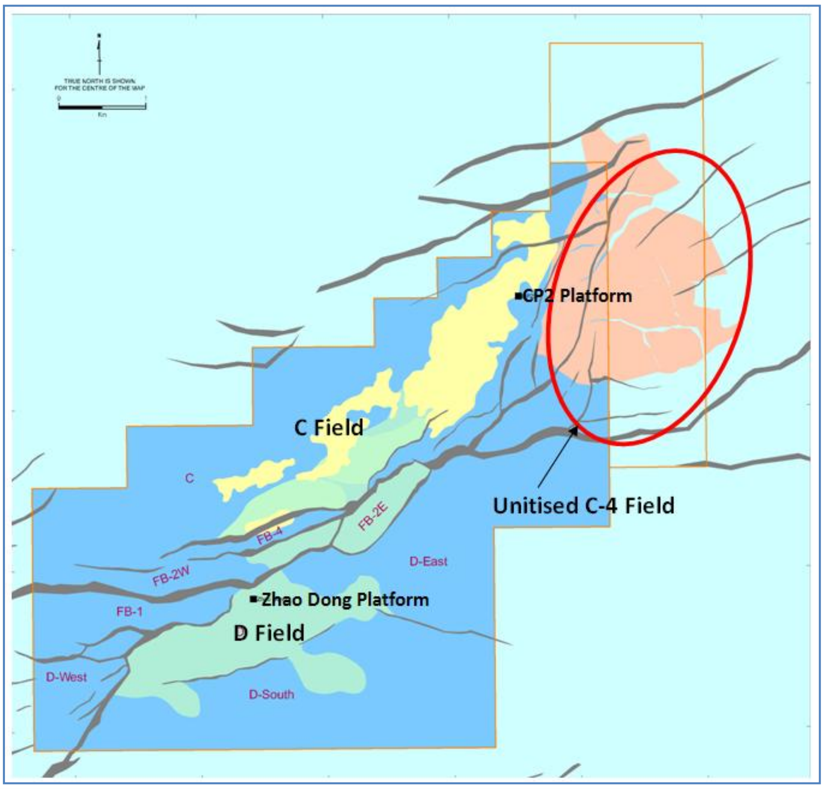


Figure 7-13 Zhao Dong and C4 oil accumulation map

A comprehensive 3D seismic data set covers the whole Zhao Dong Block and this, together with the large number of existing well penetrations in the developed C/D Fields, provides confidence in the mapping of the different horizons, and the in-place oil volumes and reserves which have been estimated for the fields. Several vintages of seismic data have been used historically; until 2008 the primary interpretation volume was a 3D dataset acquired by Apache in 1997-1998. This had been reprocessed at least once, including relatively unsuccessful post-stack inversion. In 2008 a new reprocessing project using available Petrochina data was undertaken with the aim of producing a better structural image through pre-stack depth migration. However, Roc stated that the data quality is poor over the Lower Tertiary & Pre-Tertiary section.

The pools relying on Eocene and older reservoirs are structurally defined. In the Upper Tertiary, amplitudes have been used by Roc to guide reservoir trend mapping, although these do not necessarily indicate the presence of oil.

The oldest principal reservoirs are the fluvial and lacustrine Jurassic Mz1-2/3 and Mz1-4/5 units, which contain sections of coarse conglomerate. The marginal lacustrine / deltaic Shahejie Formation provides reservoir sands in the Eocene Es2 unit. There are numerous productive intervals within the Upper Tertiary Guantao Ng (continental braided and meandering fluvial) and Lower Minghauzhen Nm (marginal lacustrine and meandering fluvial) formations. A schematic cross section showing the types of play is given as Figure 7-14.

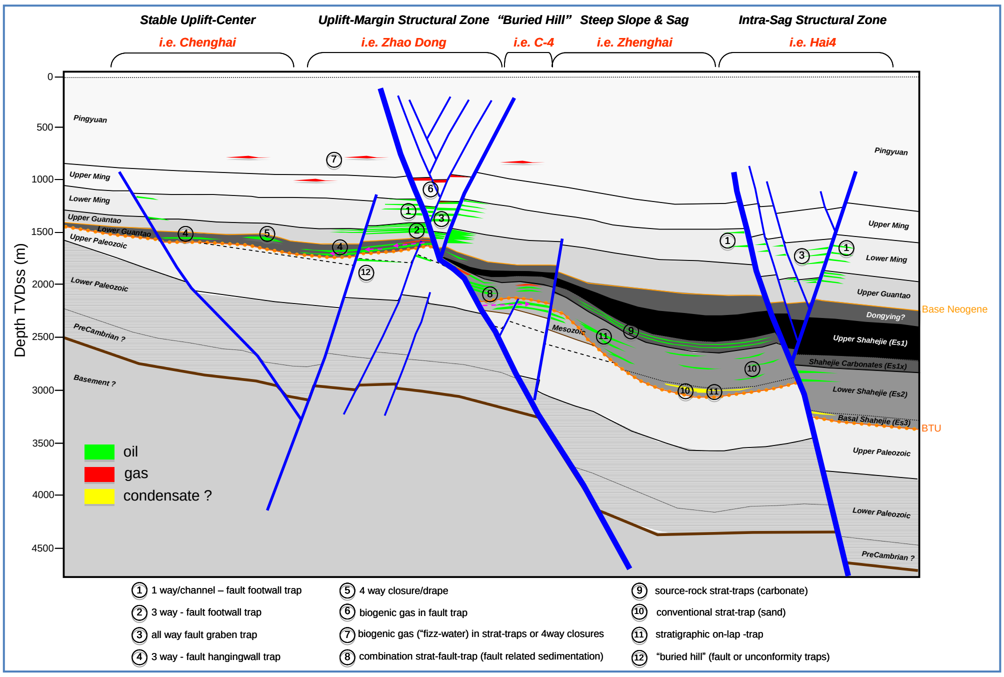


Figure 7-14 Schematic cross-section showing typical plays

RISC has reviewed and audited the methodology and input data that has been used by Roc to estimate STOIIP. Roc's volumetric probabilistic methodology is supported. We made our own assessment of the NRV and were able to support overall the Roc NRV inputs.

We have made a series of deterministic checks as a check against Roc's STOIIP range. Pool areas have been calculated from Roc depth maps by digitising of areas based on Roc's lowest known oil (LKO) (generally low case) and OWC (high case or ML as appropriate).

RISC has accepted the net pay and porosity determinations from petrophysics and used them in our volumetric calculations. In general RISC has used average net pay and average porosity values which associated with the range in areas to deterministically calculate STOIIP. This gives an acceptably wide range in STOIIP.

RISC STOIIP estimates were compared against the Roc STOIIP. Where differences were small and/or explainable, the Roc STOIIP was accepted. The largest differences were at the P90 level, although differences were always within 10%. Where differences were material RISC discussed these with Roc, who accepted RISC's proposed values. We therefore support Roc's estimate of STOIIP which range from for the Zhao Dong Field. A summary of the discovered STOIIP and reserves is included in Table 7-6 and Table 7-7. These oil volumes exclude about 30 MMstb undiscovered STOIIP.

Field	Low	Best	High
	Oil MMstb	Oil MMstb	Oil MMstb
Zhao Dong C/D	302.0	357.5	422.0
Zhao Dong C-4	27.0	40.5	60.4
Total	**329.0**	**398.0**	**482.4**

Table 7-6   STOIIP as at 1 January 2014 - Bohai Bay

Field	1P		2P		3P	
	Oil MMstb	Gas bcf	Oil MMstb	Gas bcf	Oil MMstb	Gas bcf
Zhao Dong C/D	12.7	3.0	16.0	4.3	20.8	6.1
Zhao Dong C-4	1.0	0.3	1.5	0.5	2.0	0.7
Total	**13.7**	**3.3**	**17.5**	**4.8**	**22.8**	**6.8**

Table 7-7   Gross Reserves as at 1 January 2014 - Bohai Bay

Field	2C MMstb	2C Bcf
C&D	20.2	4.5
C-4	1.4	0.4
Total	**21.6**	**4.9**

Table 7-8   Gross 2C Contingent Resources as at 1 January 2014 - Bohai Bay

Cumulative production to 31 December 2013 was 70.0 MMstb of oil and 35.6 bcf of gas for C and D fields and 4.6 MMstb of oil and 3.9 bcf of gas from C-4. Total cumulative gas sales were 7.3 bcf. From the period 1 January 2014 to 31 March 2014 there has been a further depletion of 1.3 MMstb from C/D fields and 0.17 MMstb from C-4 gross due to production. Gas sales were approximately 0.4 bcf over the same period.

7.2.2. Production and Cost forecast

The Zhao Dong offshore facilities comprise four bridge-linked platforms; two for drilling and accommodation and two for production and processing.

The C4 Field Unit facilities comprise a wellhead platform and pipelines to the C&D field platform. Production is delivered to onshore processing plant by pipelines.

Oil and gas production from Zhao Dong Block fields C&D and C4 are being augmented with an ongoing development drilling program.

Roc has used the RISC Year End 2013 reserves report as the basis for the production profiles. RISC has reviewed these and accepts their use in the evaluation. The following plots show the annual oil and gas volumes for C&D Fields and C-4.

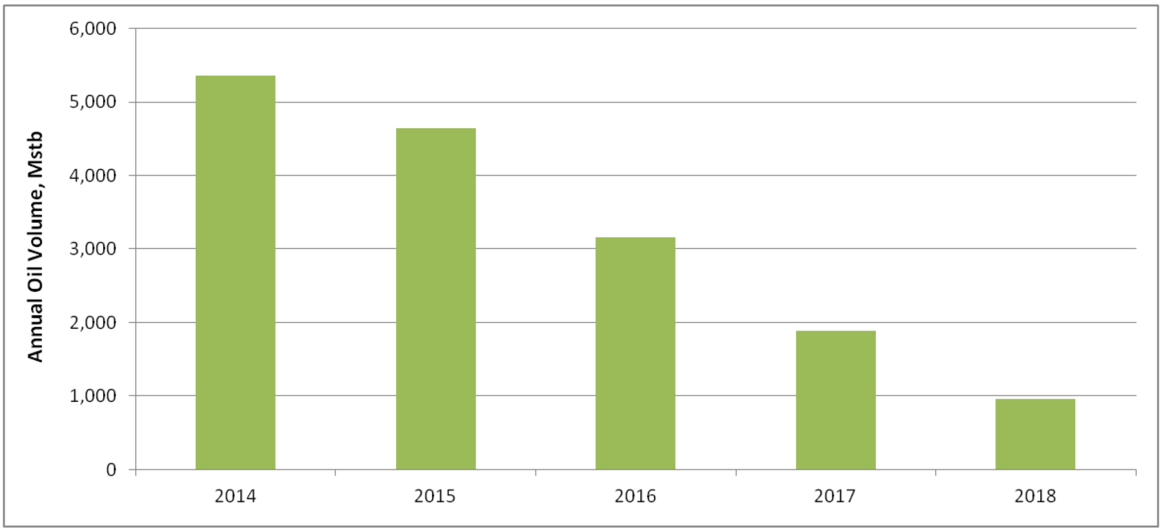


Figure 7-15 2P Gross Oil Production Forecast - C&D Fields

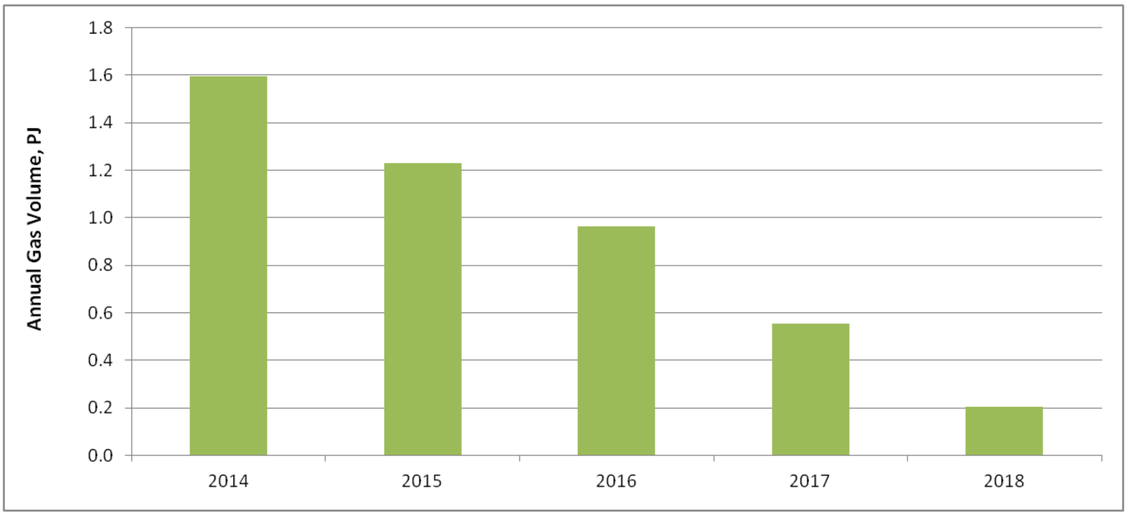


Table 7-9 2P Gross Sales Gas Production Forecast - C&D Fields

Note that in Roc's financial model, the C and D Fields were each allocated 50% of the total identified by RISC for the full C&D Field forecast. As the equity in these fields is the same, this is not a concern.

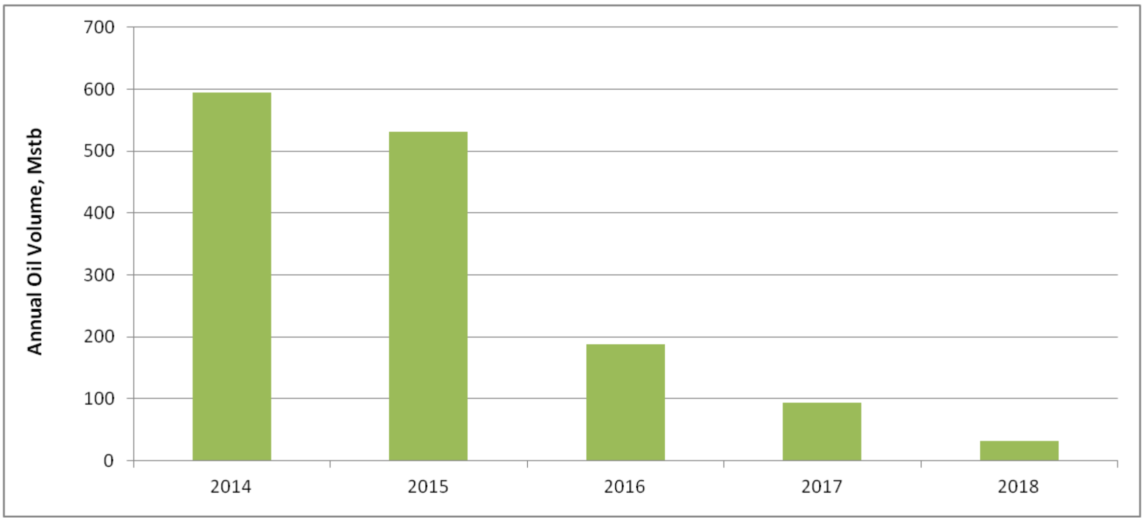


Figure 7-16 2P Gross Oil Production Forecast - C-4 Field

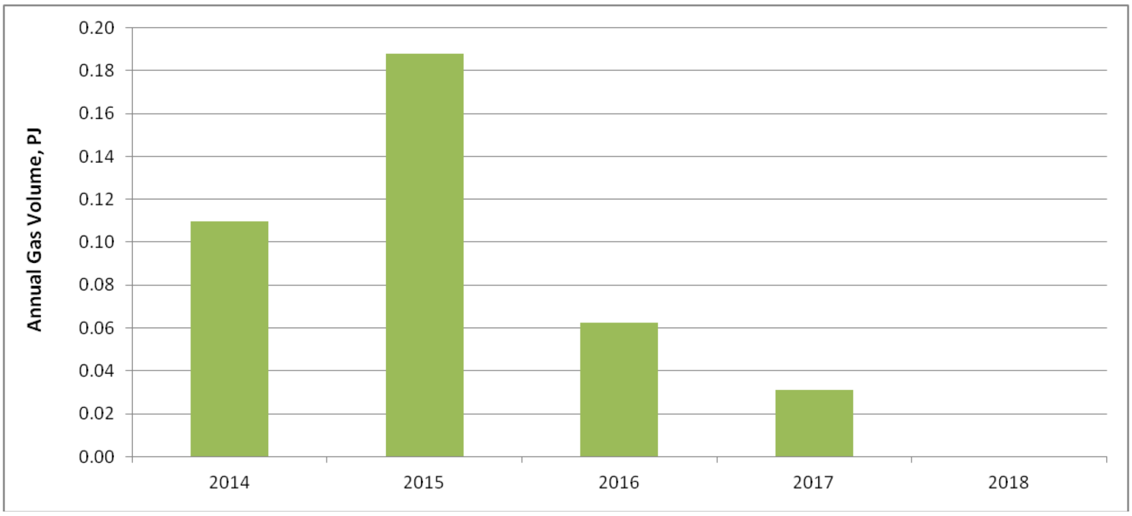


Table 7-10 2P Gross Gas Production Forecast - C-4 Field

No further production is expected from the New Block I, which ceased production in 2013.

Contingent Resource Scenario

A scenario which produces a proportion of the 2C contingent resources has been assessed.

The contingent resources were split by Roc into four categories:

- Developed, Licence Extension
- Undeveloped, Licence Extension
- Development Unclarified
- Development Not Viable

Of a total 21.6 MMstb identified within these categories, 7.7 MMstb require a licence extension and 9.3 MMstb of development projects were not viable (too small, or too difficult).

If the PSC was extended beyond the current PSC end date of September 2018, a portion of these resources may be migrated to reserves categories.

In the scenario with an approved extension of PSC period to 2023, incremental development activities could become economically attractive and could be considered new reserves. Additionally, the tail-end of the current development would be migrated to reserves.

Roc modelled this scenario with new development activities and created new cost and production profiles. The extended plan, with oil sales to 2023, has an increment of 14.4 MMstb over the RISC 2P for period 2014-2023. This plan reflects a case of 2P+2C resources with truncation at 2023. RISC has made a distinction between the volume produced in a 5-year extension, and the YE2013 2C volume. The volume beyond 2023 is not included in this scenario.

The figures below show the oil and gas production profiles for the 2P+2C case with a 5 year extension. These include C&D Fields and C-4.

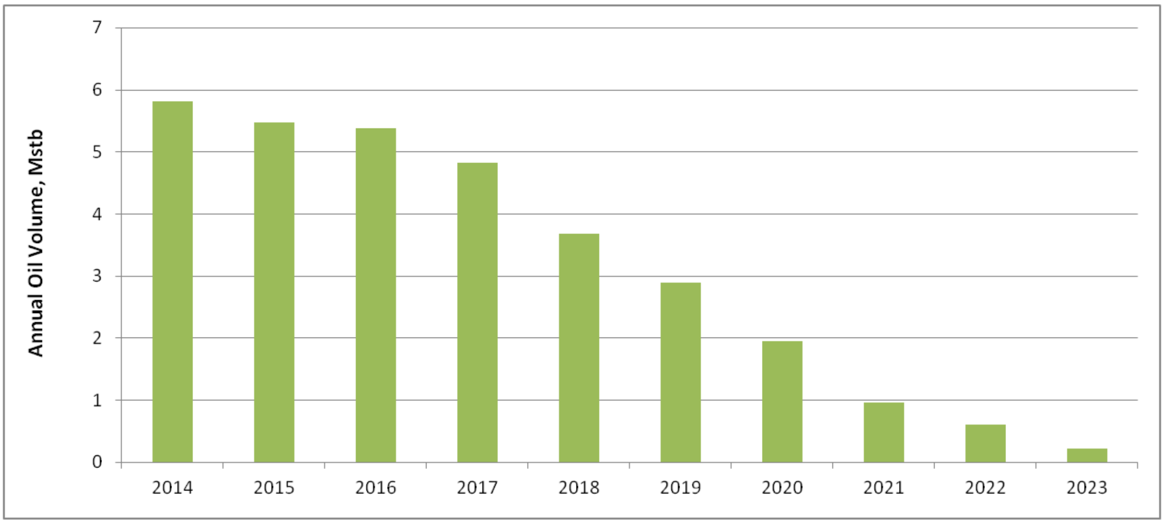


Figure 7-17 2P+2C Gross Oil Production Forecast - All Fields

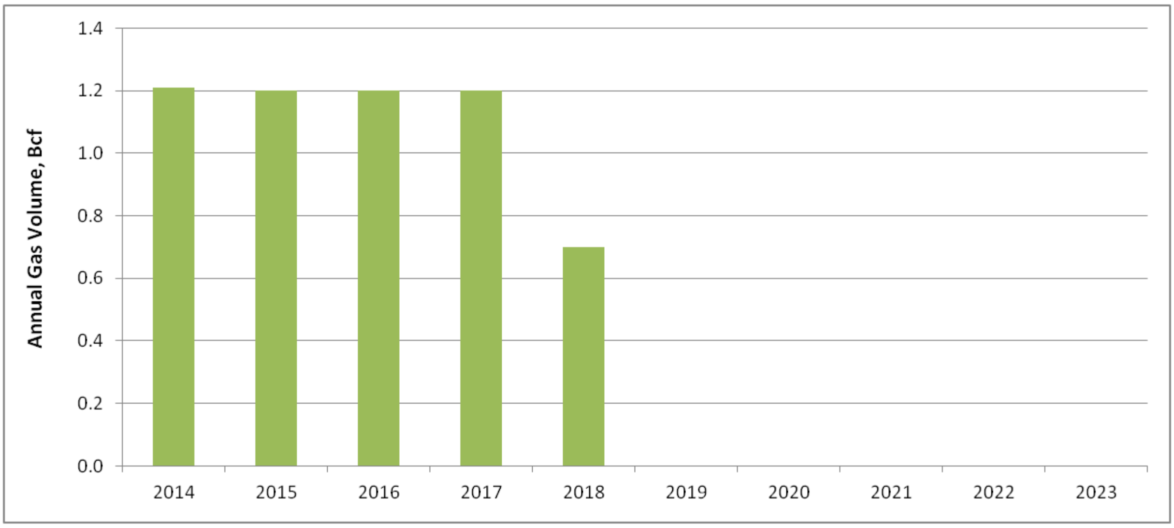


Figure 7-18 2P+2C Gross Gas Sales Forecast - All Fields

Note that sales gas volumes do not extend beyond 2018, although oil production continues to 2023 in the 2P+2C case. This due to an increasing proportion of produced gas being used for fuel.

Capital Costs

Capital costs totaling $280m are forecast for the 2P case. Most of this cost relates to drilling 42 development wells, the balance is for facilities costs including increasing water handling capacity and well hookups.

In the 2P+2C (truncated to 2023) case the estimated capital cost expenditure is $811m. The bulk of this cost relates to the drilling of an additional 77 wells and a new well head platform.

Operating Costs

Operating costs are forecast to be $499.6m (with $65.7 of abex contained in this) to end of PSC decreasing from $130m in 2014 to approx $40m in 2018 in the 2P case. In the 2P+2C case the total opex is forecast to be $720.8m (with $101.3 of abandonment costs contained in this) with a similar profile from 2014-2018 and tail costs continuing until 2023.

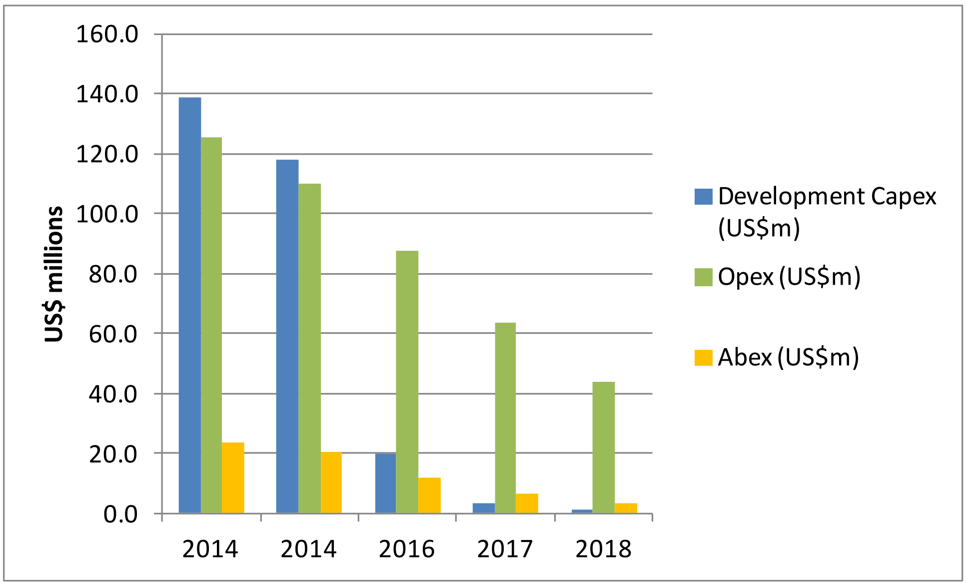


Figure 7-19   Gross 2P Costs - Bohai Bay

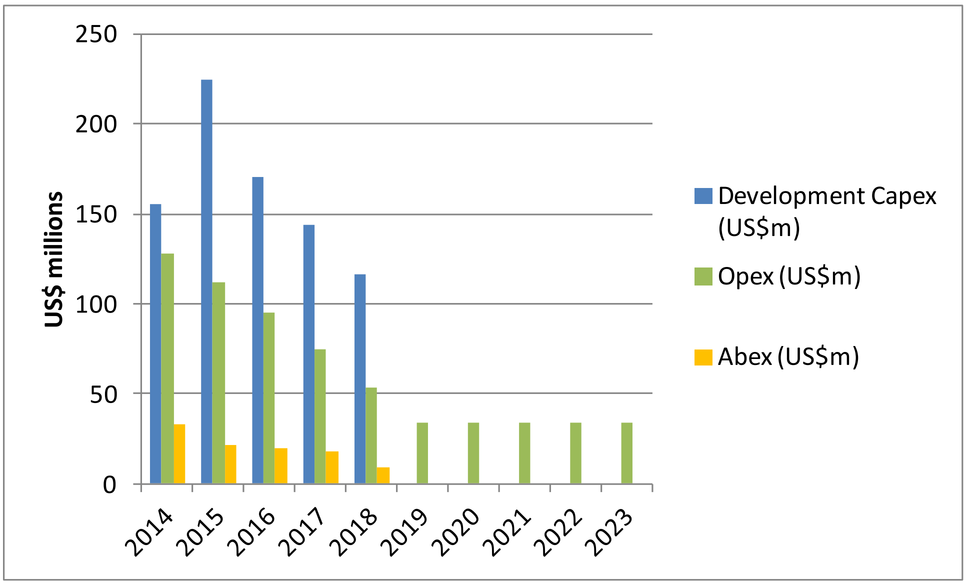


Figure 7-20 Gross 2P+2C Costs - Bohai Bay

7.2.3. Exploration

Exploration and appraisal potential exists in the 09/05, Zhanghai and Chenghai Blocks.

In March 2011, the Zhao Dong Joint Venture was awarded two additional offshore areas, adjoining the Zhao Dong PSC, as an extension to the existing acreage (Figure 7-21). Historical exploration campaigns resulted in discovery of oil in both blocks. There is potential to access portions of these new blocks from the Zhao Dong platforms, particularly areas within the Northern block. To date only one well (ZH-01P) has been put on production through the CP2 platform. Production from August 2011 to May 2013 was only 0.14 MMstb (gross) and no further reserves or contingent resources are assigned.

Roc has a 39.2% working interest in these new areas. The pool from which well ZH-01P produced straddled the block boundary and was unitised with Roc holding a net 33.5% interest.

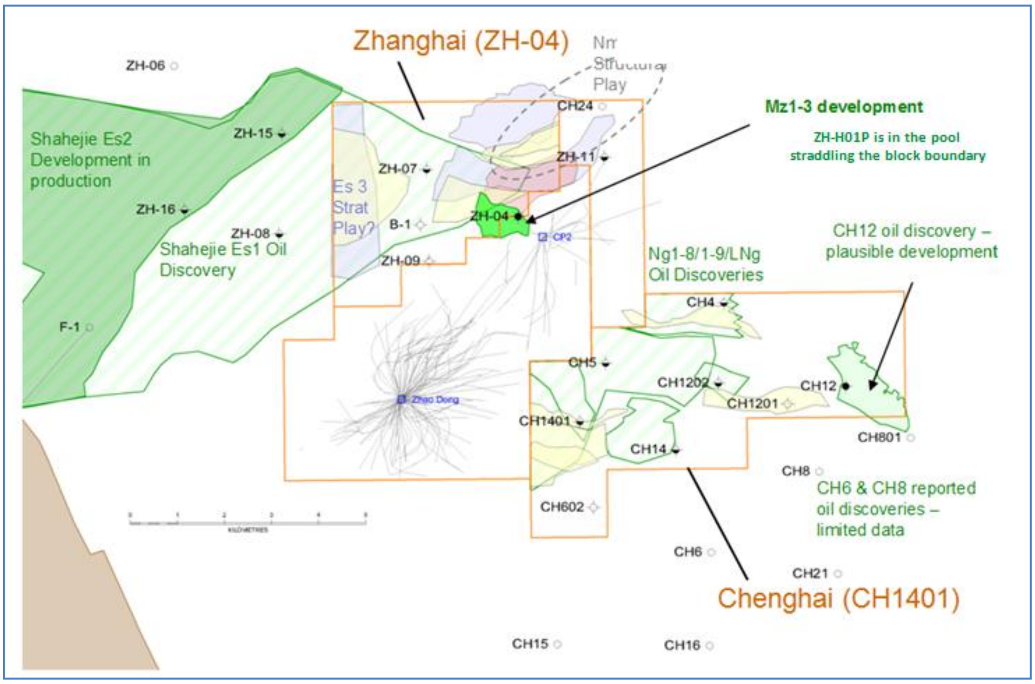


Figure 7-21 Map showing Zhaghai and Chenghai Blocks, Zhao Dong wells and Discoveries

7.2.4. Chenghai Block Development

RISC understands that the Chenghai Block contains a number of viscous oil discoveries. We have not had access to basic data on this block nor seen any mapping, log interpretation, fluid analysis or any assessment of volumetrics. RISC understands that Roc has estimated 60-80MMstb STOIIP. We have briefly reviewed some reservoir engineering work conducted by Roc that considered potential recovery methods for the viscous oils encountered in wells drilled to date.

The reported fluid properties indicate reservoir oil viscosity generally in the range from 600 to 1700 cP - although the measured viscosity on fluid samples at well CH5 is reported at 20 cP and CH1401 120-150 cP.

Roc's review of available technologies considered:

- conventional production (depletion /water drive)
- miscible solvents
- steam injection
- polymer flooding
- combustion floods

Roc concluded that the technology for developing the higher viscosity crudes at reservoir depths of 1450 mss in an offshore cost environment is not reliably available, although there could be scope to apply onshore technologies, however in the absence of valid analogues this would be a frontier application.

No contingent or prospective resources have been assessed to date.

RISC has assigned no further value to the exploration in the Zhanghai and Chenghai blocks,

Horizon had an option to farm into Block 09/05 for a 40% interest by paying 40% of the ongoing costs to earn the option and the right to farm into a 40% interest by drilling two exploration well at a 2:1 promote. The option has since expired and Roc now holds 100%.

Block 09/05 2014 budget has an amount of $21.1 million including $1 million for G&G studies and $14.7 million. There is a further contingent budget of $1.7 million for seismic and $9.2 million for drilling.

Assuming that Roc can attract the same terms as Horizon offered and assuming a 2 well cost plus studies and seismic of $26.6 million, this values the block at $26.6 million. However there is no certainty that similar terms could be obtained. In the low and mid cases, we have assumed a 2:1 farmin on the firm G&G studies and a well for a total cost of $15.7 million, which would value the permit at $15.7 million. The high case value is $26.6 million.

8. PAPUA NEW GUINEA

8.1. PRL 4

8.1.1. Stanley Field Description

The Stanley Field is located in permit PRL4 (Figure 8-1). Horizon has a 30% interest in the permit, which will reduce to 23.25% in the event that the PNG Government exercises its back-in rights of up to 22.5%. The permit is operated by Talisman Nuigini Pty Ltd.

In April 2014, the Stanley Project was approved by the PNG Government and the development licence (PDL 10) was awarded on 30 May 2014. The Stanley project entails the production of 140 million cubic feet (MMscf/d) of gas per day from two wells, extraction of initially over 4,000 barrels of condensate per day with re-injection of the dry gas until a gas market develops. First production is scheduled for mid 2016.

Options to monetise the gas include supply to the Ok Tedi and Frieda River mines or local users for power generation and/or gas export via a 1-2 Mtpa LNG project under consideration. The potential to sell gas into third party LNG projects also exists.

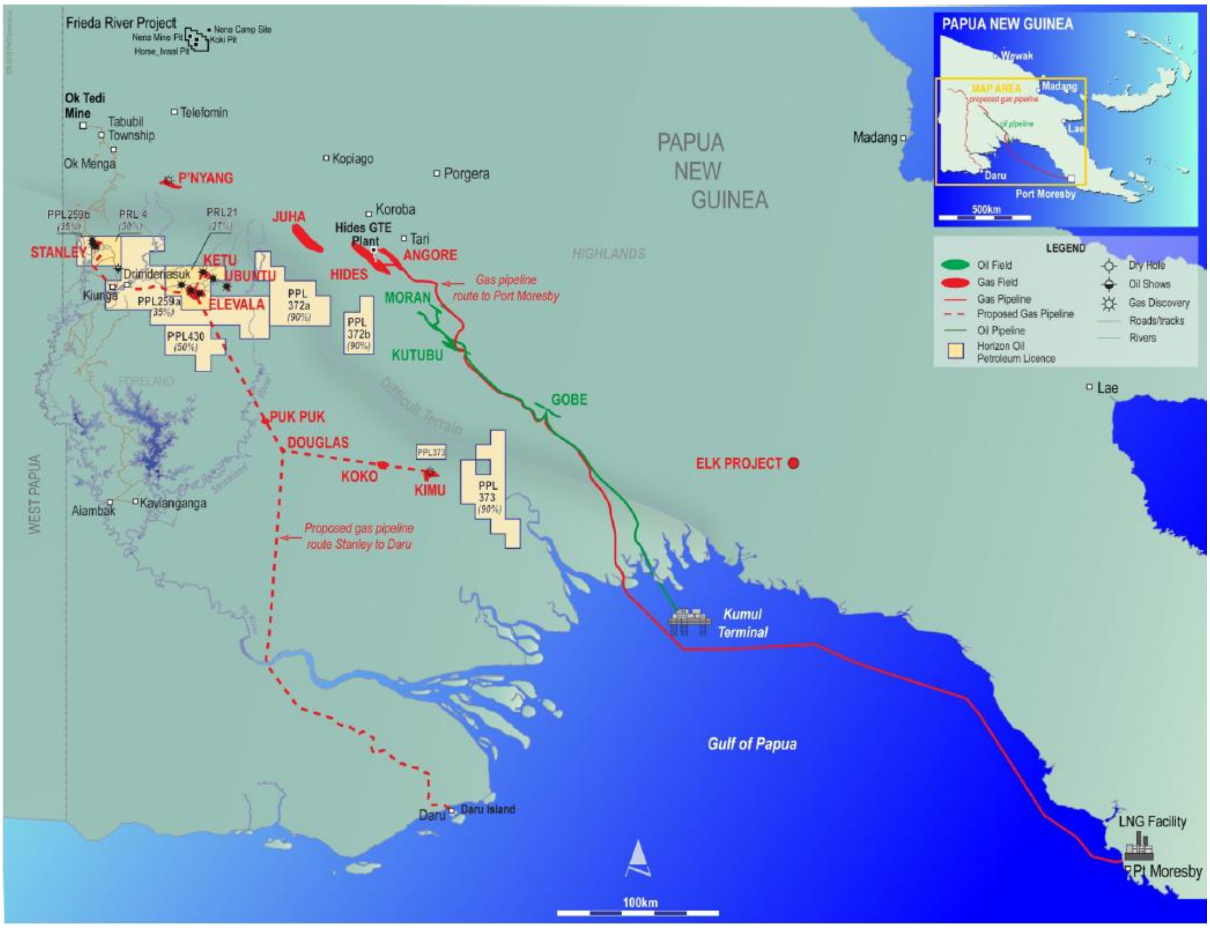


Figure 8-1 Horizon PNG Interest Location Map

Three wells and one sidetrack have been drilled to date on the Stanley structure. Stanley-1 was drilled in 1999 and discovered gas in the Toro Sandstone, which was later tested by Horizon in 2008 at a rate of 9 MMscf/d gas. The well subsequently flowed gas on open flow at 30 MMscf/d.

In 2011, Stanley-2 was drilled as a near vertical well targeting the Toro reservoir on the crest of the structure, with the additional objective of testing for deeper reservoirs. The well proved the Toro Sandstone to be gas bearing on the central portion of the field with 22.1m of net gas sand, and also encountered a deeper gas bearing reservoir, named the Kimu Sandstone, with 41.2m of net gas sand. Both reservoirs encountered gas to the base of reservoir and demonstrated a common gas gradient consistent with the gas column at Stanley-1.

In order to obtain a full suite of core across the gas bearing reservoirs, the well was sidetracked as Stanley-2ST1 adjacent to the original wellbore. Stanley-2ST1 encountered a similar net gas sand thicknesses to Stanley-2 in the Toro and Kimu reservoirs as expected. The sands then completed and tested gas separately at up to 30 MMscf/d and up to 40 MMscf/d respectively.

The field extends into the adjacent PPL259 permit and is the subject of a unitisation determination. However since Horizon has 30% interest in PRL4 and a 35% interest in PPL259 (prior to PNG Government back-in) it is largely hedged against the unitisation outcome and will have minor impact on Horizon's interests. As this is commercially sensitive, we have not included a structure map.

Probabilistic gas and condensate in place have been calculated for both the Toro reservoir and the Kimu reservoir. Static modeling has been undertaken to provide input into the dynamic modeling. RISC considers the static model reasonable and adequate for this purpose. RISC has audited the reserves and resources as at 30 June 2012 (Table 8-1). We are satisfied that that there is no new information available since that date which would have a material bearing on our conclusions.

	P90	P50	P10
GIIP bcf	474	591	728
CONDENSATE IN PLACE MMbbl	14.2	17.7	21.8
Reserves	**1P**	**2P**	**3P**
Condensate (MMbbl)	8.3	11.4	14.4
Contingent Resources	**2C**		
Gross Gas (bcf)(1)	399		
Condensate (MMbbl)(2)	1.3		

Notes:
(1) Includes potential LPG resources with a yield of 1.97 tonne/MMscf
(2) Approximately 10% of condensate recovery is attributed to the gas sales phase and is a contingent resource pending gas commercialisation

Table 8-1 Stanley Field Gross Reserves and Resources as at 30 June 2012

8.1.2. Production and Cost forecast

8.1.2.1. Project Overview

The Stanley development will consist of two production and two dry gas injection wells. Two of these wells Stanley-2ST1 and Stanley-4 were drilled in 2011. Stanley-2 will be used as a producer from the Toro and Kimu sands. Stanley-4 will be used as a gas injector for the Kimu. Two additional wells Stanley-3 and 5 will be drilled.

The gas plant will be located near the existing wells, where site clearance is largely completed. The facilities scope includes 2 x 50% processing trains capable of processing a total of 140 MMscfd nameplate capacity gas (133 MMscf/d annual average). Initial condensate rate is expected to be just over 4000 bbl/d annual average. Main components of the gas plant are as follows:

- 2 x 50% 70 MMscf/d Inlet Separator Modules;
- 2 x 50% 70 MMscf/d Refrigeration Modules;
- 4 x 25% 35 MMscf/d Gas Driven Injection Compressors;
- 1 x 100% Condensate Stabilization Module;
- 1 x 100% Re-cycle Compressor;
- 2 x 100% Condensate Transfer Pumps;
- 1 x 40,000 Bbl condensate tank;
- 2 x 50% 70 MMscf/d Mercury treatment beds;
- 2 x 50% 2,000 bpd Mercury treatment beds;
- 1 x 60,000 Bbl condensate storage tank at Kiunga lay down area;
- 2 x 100% Condensate Transfer Pumps at Kiunga Condensate Transfer Station;
- 3 x 50% GENSETS at Stanley Gas Plant;
- 2 x 100% GENSETS at Kiunga Condensate Transfer Station.

Processed gas from the Stanley Gas Plant will be used for the following:

- fuel gas for power, compression and process;
- remaining gas will be re-injected into the reservoir;
- As and when gas markets become available (e.g. power generation at mine sites) gas will be exported to various customers.

Stabilised condensate produced by the Stanley Gas Plant will be shipped via a 40 km 6" pipeline to a new loading terminal located on the Fly River at Kiunga. Kiunga is a major river port with infrastructure that allows significant quantities of copper to be shipped from the OK Tedi copper mine. The proposed condensate shipping facility will be located near the Kiunga airport at the site of an existing staging area used to support drilling operations. A short 1 ½ km condensate transfer pipeline will move the product from the shipping facility to a riverside wharf on the Fly River, approximately 1 km downstream of the OK Tedi wharf at Kiunga.

8.1.2.2. Cost and schedule estimates

RISC has reviewed the Horizon cost and schedule basis for the Stanley field development and in the main finds them to be reasonable. RISC has made adjustments to the project budget to include the effect of project delays and added contingency on some items where necessary. The Stanley capital cost estimate is shown in Table 8-2.

There has also been a change of operatorship, with Talisman assuming the role of operator, and this has the potential to further delay the project. Nevertheless, RISC believes that a two year project execution schedule is achievable and considers that a start-up date of 1 July 2016 is achievable provided that the production licence is awarded as planned.

Cost Item	US$ Million
Project Management and Supervision	15
Stanley Gas Plant	221
Pipeline	40
Kiunga Storage and Load out facilities	27
Wells (including Stack costs)	78
Total Capital Cost	**381**
Abandonment	**38**
Operating Cost/year	**26**

Table 8-2 Stanley Gross Capital and Operating Costs as at 1.1.2014 - RISC estimate

Operating costs for the Stanley development, as indicated in the Horizon corporate model, are approximately $26 million per year including condensate transport costs. RISC has reviewed the operating costs and considers these costs reasonable.

The above capital and operating costs are also appropriate for both a stand-alone liquids stripping scheme and a scheme which includes future gas sales on the basis that all the necessary equipment is already in place and on the assumption that the gas is sold on an ex-field basis (Figure 8-2). In the case of gas export, opex extends until 2041.

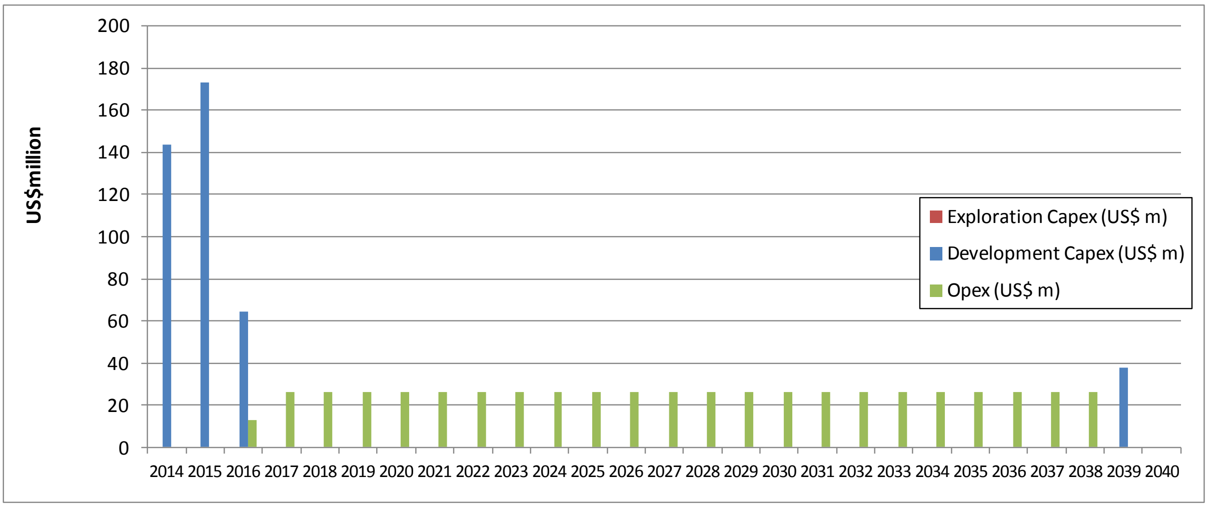


Figure 8-2 Stanley 2P Liquids Stripping Gross Cost Forecast - RISC Estimate

8.1.2.3. *Production forecast*

RISC has considered two production scenarios:

2P Reserves Case
A stand-alone liquids stripping scheme which produces the 11.4 MMbbl of condensate reserves.

Horizon have generated a dynamic simulation model of the Stanley field to evaluate a range of development and production concepts. RISC has reviewed the model inputs and made changes where necessary. Production forecasts at the 2P level have been generated by RISC for condensate stripping (with lean gas reinjected back into the reservoir). Condensate stripping is assumed to commence in July 2016. The field is assumed to produce raw gas at a capacity of 140 MMSCFD before an allowed downtime of 5% which yields an average raw gas rate of 133 MMSCFD, and lean gas is reinjected at an average rate of 124 MMSCFD after condensate is removed and a small amount of gas is used for fuel and flare. The production and cost forecasts are shown in Figure 8-3 and Figure 8-2.

The condensate-gas ratio (CGR) for Stanley gas has been derived from PVT analysis of eighteen downhole and surface gas and condensate samples from the Toro and Kimu reservoirs. The expected produced initial CGR is approximately 30 bbls per MMSCF taking into account process yields and will be able to remove condensate from the gas down to a level of 3 bbls per MMSCF. The produced CGR will decline as lean gas breaks through in produces and the reservoir pressure decreases.

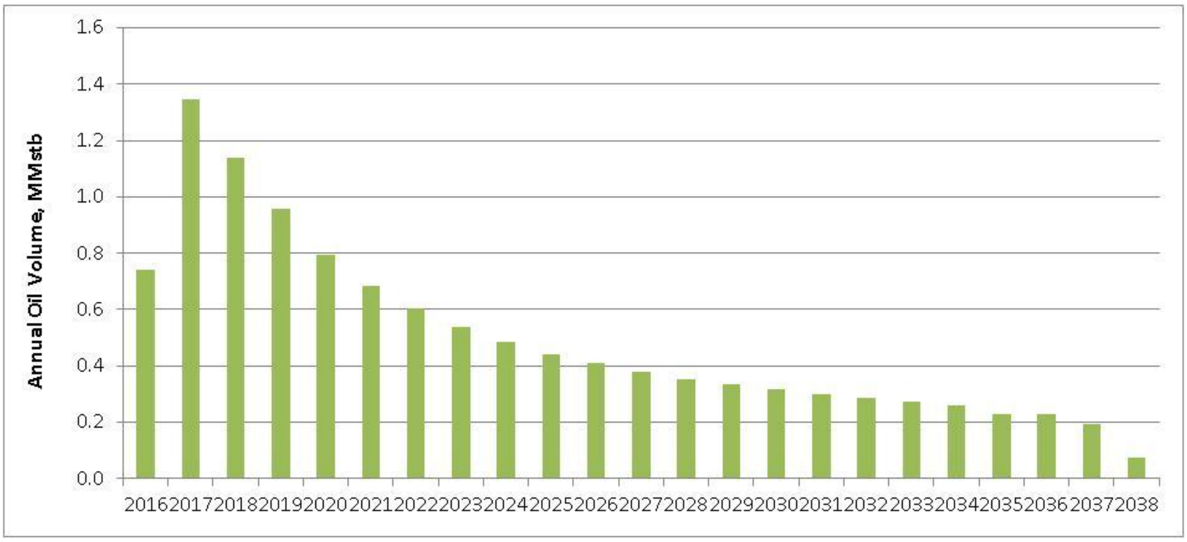


Figure 8-3 Stanley 2P Gross Production Forecast – Condensate stripping only

2P+2C Resources Case
In this scenario, liquids stripping for 3 years is followed by gas export. This develops the 2C gas resources and an additional 1.3 MMstb of condensate from the field blowdown. Lean is reinjected back into the reservoir for three years and condensate removed and sold, after which time a gas sales opportunity has been captured and the lean gas is instead exported. In the RISC forecasts, produced gas is assumed to be sold to Ok Tedi mine (power generation) at a rate of 2.4-3 PJ/a ,with the remainder to 18 PJ/a available for sales to the potential Frieda River mine and other potential buyers of gas in the region.

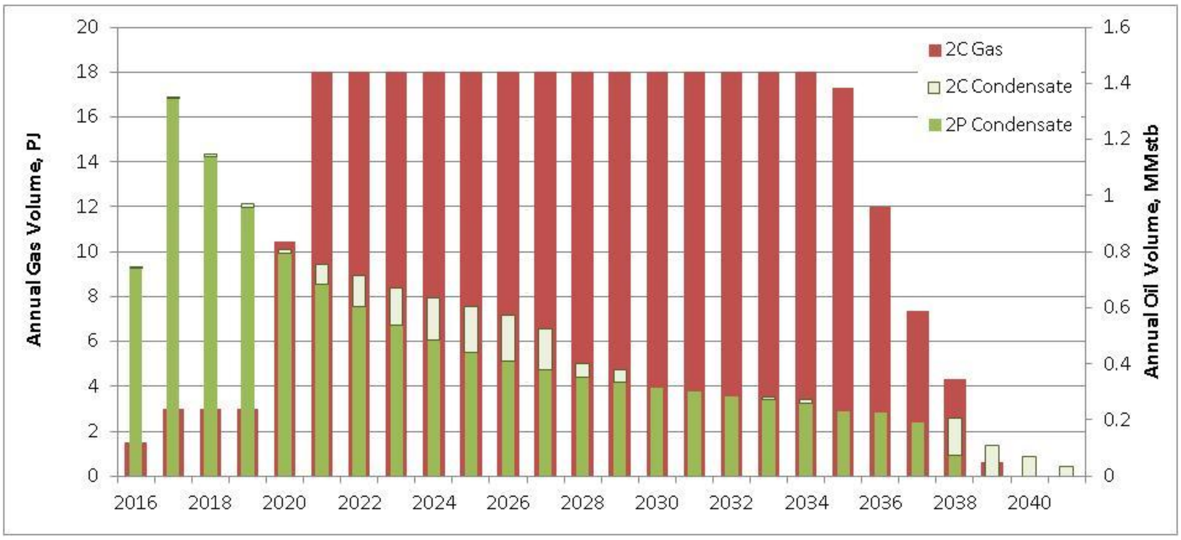


Figure 8-4 2P+2C Gross Production Forecast – Condensate stripping and gas export

The liquids stripping project is already approved and risks associated with the gas sales are primarily commercial in nature. We consider the technical risks associated with this scenario to be low and have not made any adjustment for risk.

8.1.3. PRL 4 Exploration

There is potential for additional closures located to the northeast of the Stanley field to be drilled and tied back to the Stanley development. It is expected that prospective incremental structures will be firmed up when further drilling on the Stanley Field has been completed and uncertainty in the depth conversion calibrated further. Exploration drilling, if justified, would not be undertaken until after 2016 when the drilling results from Stanley and possibly further seismic acquired.

Note that PDL 10 (Stanley field) will only be awarded over graticular blocks 1622 (contained in PPL 259) and 1623 (one of a total of 4 graticular blocks in PRL 4). Following award of PDL, the remaining 3 blocks are released back to the State to be subject to a public tender. Horizon, Talisman and Osaka Gas have submitted an application to the State to extend the life of the remaining blocks contained in PRL 4.

We have not assigned any exploration value to this permit.

8.2. PRL 21

8.2.1. Elevala and Ketu Field Description

Horizon has a 27% interest in PRL 21 which will reduce to 20.925% assuming the PNG Government excercises its back-in rights. PRL 21 is located to the east of PRL 4 (Stanley field) and contains the Elevala and Ketu gas condensate fields (Figure 8-1). The operator is Horizon.

Horizon has prepared a preliminary field development plan and submitted a development licence application for the Elevala and Ketu fields. The development concept is analogous to the Stanley Project but on a larger scale. The concept involves producing an annual average rate of 210 MMscf/d (140 MMscf/d from Elevala and 70 MMscf/d from Ketu) and reinjecting lean gas back into the reservoir. Options to monetise the gas include gas export via a 1-2 Mtpa LNG project under consideration or sale into third party LNG projects.

The Elevala Field was discovered by the Elevala-1 well drilled by BP in 1990. The well encountered gas throughout the Elevala Sandstone reservoir and gas shows in the deeper Toro reservoir. The Elevala reservoir was tested, flowing gas at a rate of 11.9 MMscf/d. An attempt was made to test the Toro reservoir which was unsuccessful, leaving the test string in the hole and precluding a further test attempt. Potential for gas in the Toro reservoir below the Elevala and Tingu structure exists and has been noted as prospective resources.

The Ketu Field is located 14 km northeast of Elevala. The Ketu-1ST well was drilled in 1991 by BP and encountered similar gas condensate in the Elevala Sandstone with no evidence of a GWC (the original hole was abandoned due to hole conditions and a sidetrack drilled).

The Elevala-2 appraisal well was drilled in late 2011, encountering approximately 19m net gas bearing reservoir in the Elevala Sandstone. The well was sidetracked downdip into Elevala-2ST1 in order to establish the GWC, and encountered approximately 17m of water wet Elevala Sandstone. Pressure data acquired in both wellbores enabled a determination of the gas water contact at -3,045 mTVDss across a shale between two sands. The western lobe of the structure was drilled in August 2013 by the Tingu-1 well which confirmed the extension of the Elevala field into the eastern lobe and now incorporates the Tingu accumulation. The Tingu-1 well was tested at up to 46 MMscf/d and encountered the GWC at -3,044 mTVDss. The Toro sandstone was encountered water bearing at the Tingu-1 location, however updip gas potential remains.

The structure of the fields are defined by grid of 2D seismic data, with a line spacing of 1.5 to 2.5km between dip lines and 4km between strike lines, of different vintages and variable quality. The time and depth mapping has been reviewed by RISC and is supported.

Elevala is shown to be an areally large, low relief structure, closing against faults to the south and possibly bisected by a northeast-southwest fault (Figure 8-5).

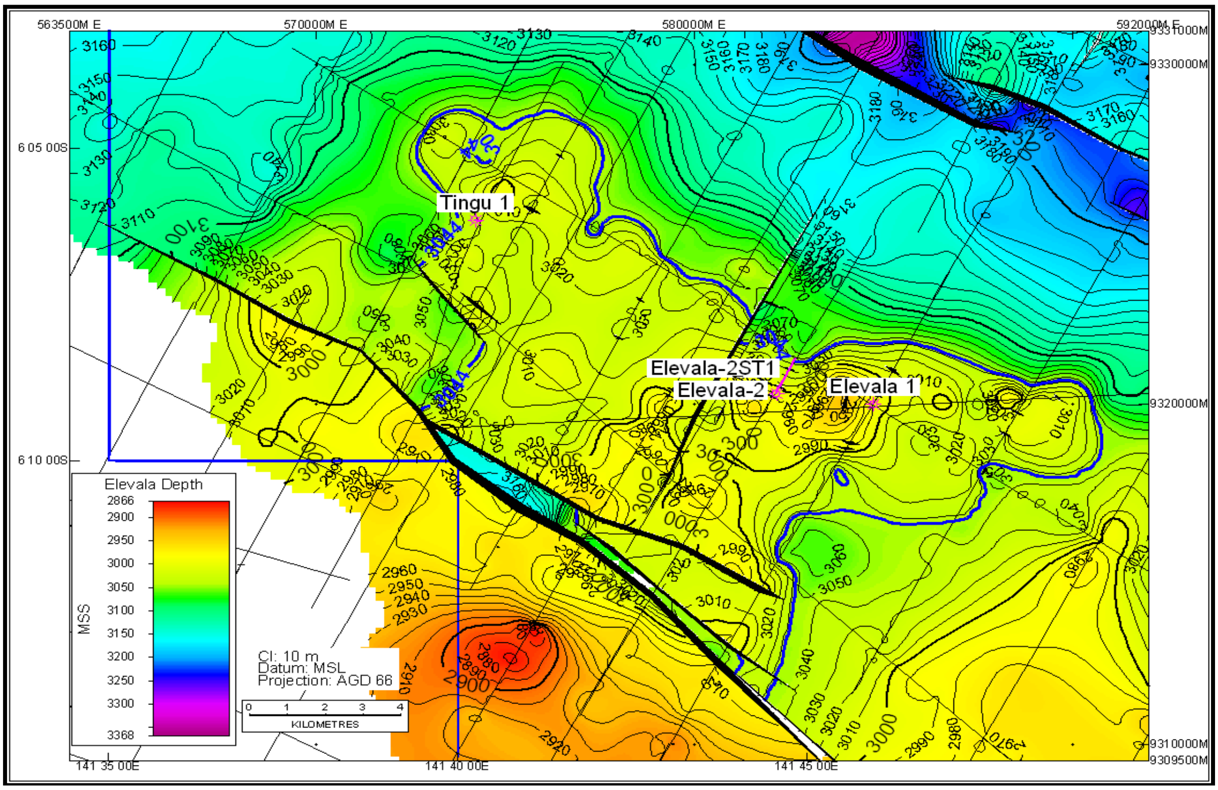


Figure 8-5 Elevala Field Elevala Reservoir Depth Structure Map

The Ketu Field has a range of potential gas water contacts of 3,220 to 3,235 mTVDss, determined pressure gradients. The Ketu Elevala reservoir depth structure map is shown in Figure 8-6.

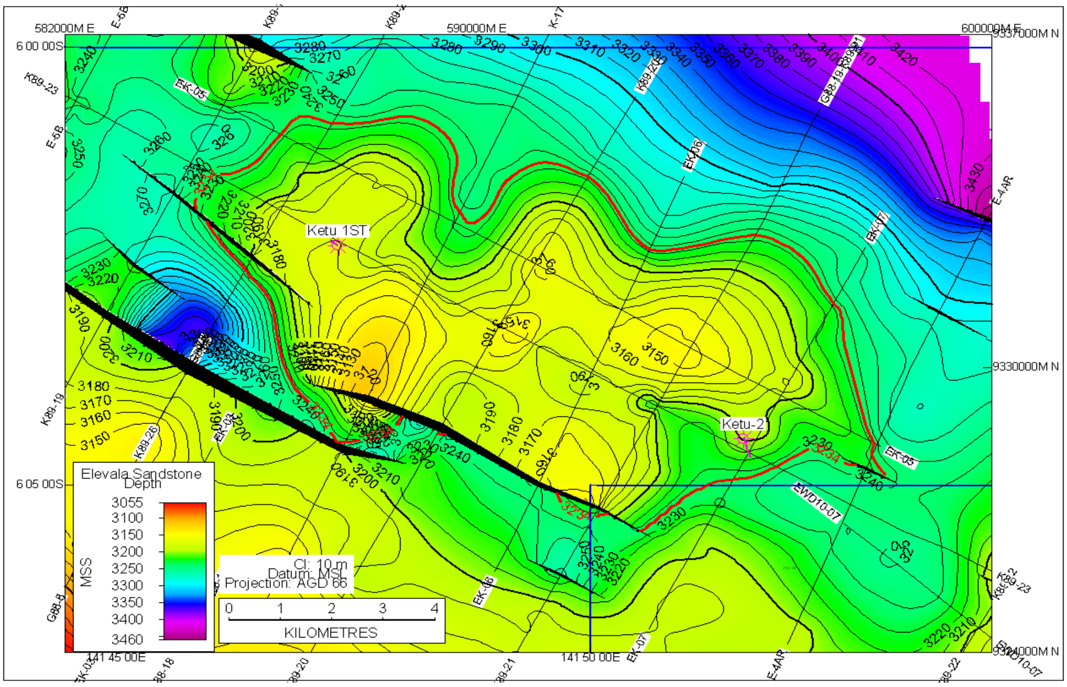


Figure 8-6 Ketu Field Elevala Reservoir Depth Structure Map

Static and dynamic modeling has been undertaken. RISC considers the reference case model reasonable. The reference case static models was used as the input for the dynamic modeling.

RISC has reviewed the reference case static and dynamic models and considers them fit for purpose given the project maturity level. Horizon intends to undertake further uncertainty modeling prior to the project FID decision in late 2014. RISC independently calculated a similar range of resources and therefore supports the resource ranges derived by Horizon shown in Table 8-3 .

	2C Gross Contingent Resource		
	Elevala	Ketu	Total
GIIP (Bcf)	1258	522	1780
Condensate in Place (MMstb)	65.8	31.3	97.1
Gross Gas EUR (Bcf)	688	291	979
Gross Condensate EUR (MMstb)[1]	35.4	14.2	49.6
1. Volumes are for gas export scenario. Liquids stripping stand alone recovers 51 MMstb.			

Table 8-3 Elevala and Ketu Gross 2C Contingent Resource Estimates as at 1 January 2014

8.2.2. Production and Cost forecast

RISC has evaluated two development cases:

Liquids Stripping
This concept is based on the following development:

- 5 wells, 2 producers and 2 injectors in Elevala and 1 producer in Ketu
- A gas plant similar in design to the Stanley gas plant, but with 3 production trains and a total production and injection capacity of 240mmscf/d (resulting in an annualized capacity of 210mmscf/d when downtime is taken into account).
- Condensate will be exported via a 60km pipeline to a new storage and ship loading facility located at Drimdemasuk on the Fly River (North of Kiunga).
- Total gross condensate production over the 20 year project life is 51 MMstb

Liquids Stripping plus gas Export
The facilities installed are identical to the liquids stripping project, however gas injection ceases after 3 years when 210 MMscf/d nameplate capacity gas sales to a 1.5 Mtpa nameplate capacity (1.3 Mtpa annual average) LNG project begins. It is assumed that the gas is sold on an ex-field basis, so no new facilities are required.

Total gross gas produced is 1,024 PJ with 49.6 MMstb of condensate.

8.2.2.1. Cost and schedule estimates

RISC has reviewed the Horizon cost and schedule basis for the Elevala and Ketu field development. We conclude that the project cost estimates are reasonable, but we consider the project schedule to achieve a start-up date of 1/1/2018 as proposed by Horizon may be optimistic.

Whilst we believe a 36 month project timeframe to be reasonable for the duration of the execution phase, We consider that, given the current position of the project, the requirement for JV and government and regulatory approvals will put pressure on the schedule. The specific cause and impact of delay is difficult to predict at this point, and we therefore have evaluated a sensitivity of a 12 month delay to start-up to the beginning of 2019. This also has some impact on project costs, and we have therefore revised the project costs in line with our expectations.

We note that Horizon have included a 20% contingency on the facility costs, and support this level of contingency at this point. We have compared estimated well costs with the currently proposed Stanley wells, and support the well costs on the basis of a standard US$35 million per well at this point.

RISC's Elevala-Ketu capital cost estimates are shown in Table 8-4.

	1/1/2018 start up US$ Million	1/1/2019 start up US$ Million
Development Planning (Pre FID)	33	60
Gas Plant	388	390
Pipeline	210	210
Terminal, Storage and Load out facilities	40	40
Roads	55	55
HSE, Regulatory, PM & Owners Costs	52	55
Contingency (20%)	143	149
Wells (5)	175	175
Total Cost	**1095**	**1135**
Operating Cost/year	**50**	**50**

Table 8-4 Elevala-Ketu Gross Capital and Operating Costs - RISC estimate

Operating costs for the Elevala-Ketu development are approximately US$50 million per year including condensate transport costs. RISC has reviewed the operating costs and considers these costs reasonable. The capital and operating profiles for the 2018 and 2019 start up cases are shown in Figure 8-7and Figure 8-8.

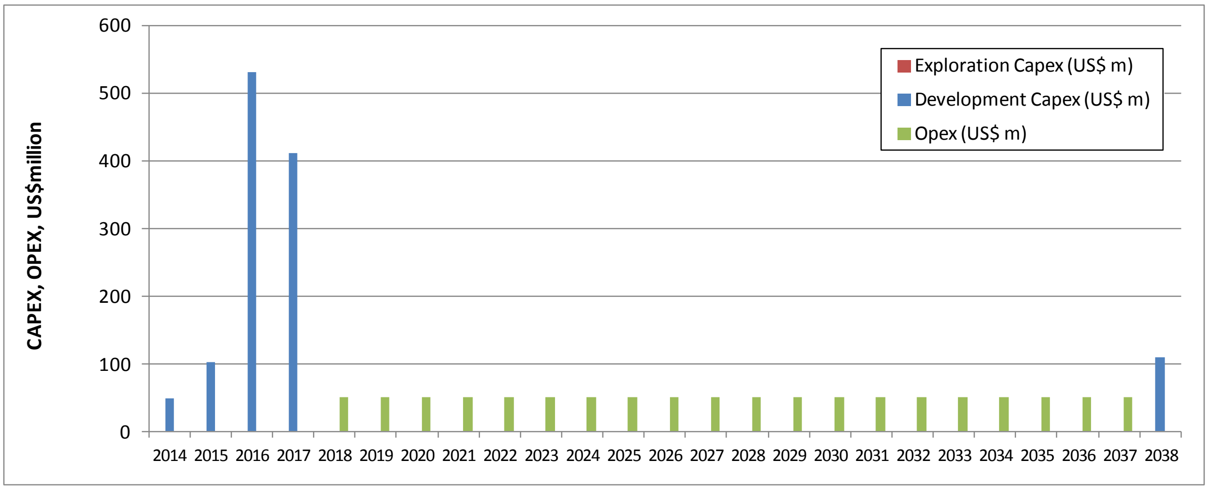


Figure 8-7 Elevela-Ketu Gross Cost Forecast - Liquids Stripping Only 1/1/2018 Start Up

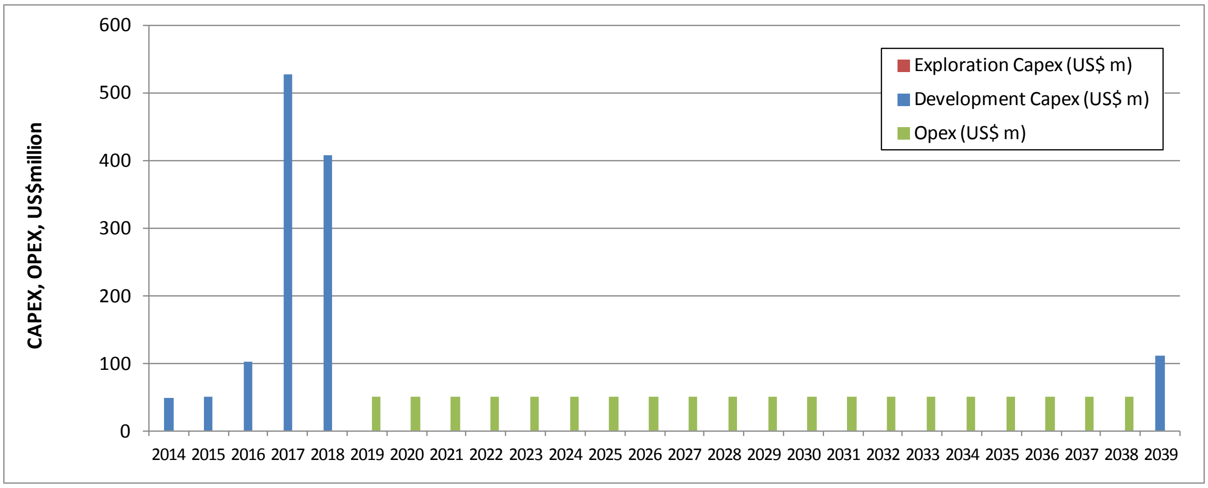


Figure 8-8 Elevela-Ketu Gross Cost Forecast - Liquids Stripping Only 1/1/2019 Start Up

8.2.2.2. Production forecasts

The condensate-gas ratio (CGR) for Elevala and Ketu gas has been derived from a number of downhole and surface samples of gas and condensate. After accounting for process yields, the expected produced initial CGR for Elevala gas is 52 bbls per MMSCF which will decline as lean gas breaks through in produces and the reservoir pressure decreases. Ketu gas, after similar process modeling, is expected to have an initial CGR of 57 bbls per MMSCF.

Horizon has generated dynamic simulation models of the Elevala and Ketu fields to evaluate a range of development and production concepts. RISC has reviewed the model inputs and made changes where necessary. Production forecasts have been generated by RISC for condensate stripping (with lean gas reinjected back into each field). Condensate stripping is assumed to commence in January 2018.The Elevala field is assumed to produce raw gas at a capacity of 140 MMSCFD, while the Ketu field is produced at 70 MMSCFD before condensate is stripped. Downtime of 13% has been assumed.

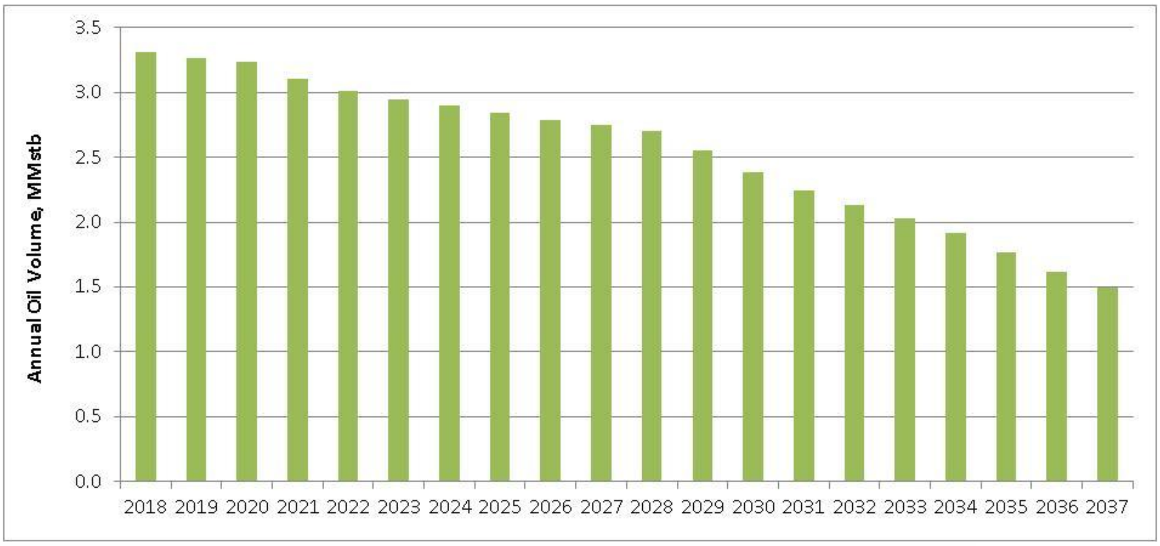


Figure 8-9 Elevala-Ketu 2C Gross Production Forecast – Condensate stripping only

RISC has also generated forecasts for a gas export development, whereby lean is reinjected back into the Elevala and Ketu fields after condensate stripping for three years, by which time the lean gas is instead exported to an 1.5 MTPA LNG facility at an equivalent raw gas rate of 210 MMSCFD.

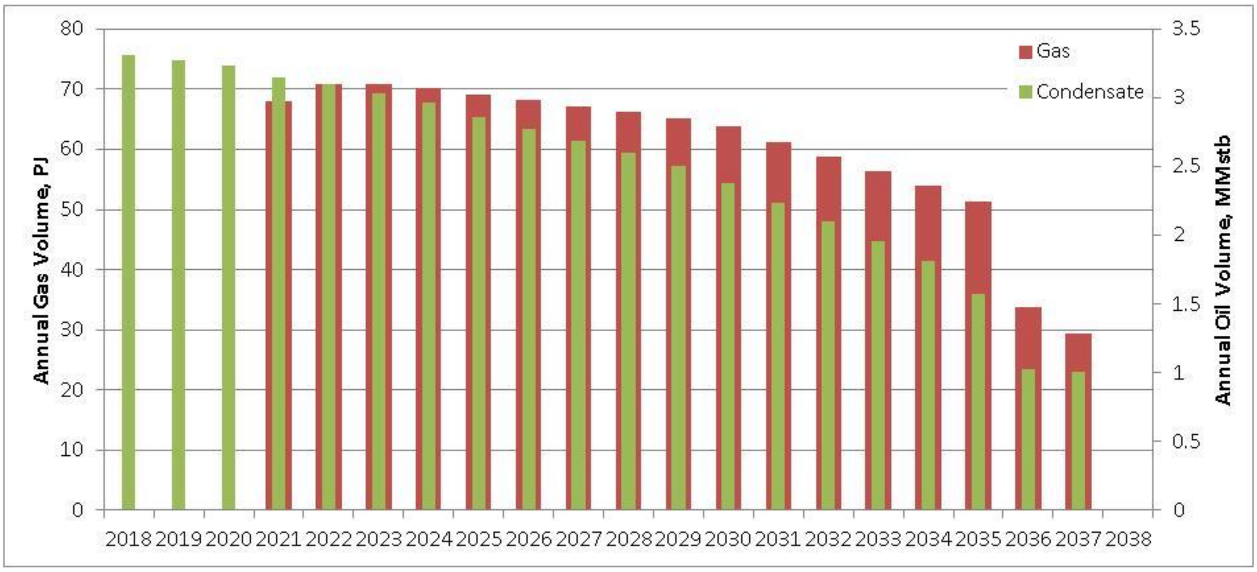


Figure 8-10 Elevala-Ketu 2C Gross Production Forecast – Condensate stripping and gas export

8.2.3. Gas Export (via Mid-scale LNG)

RISC has reviewed the estimated capital and operating costs provided by Horizon for their indicative netback pricing calculations.

The base scenario put forward by Horizon includes an export gas (and condensate) pipeline to Mugumugu, where a barge mounted LNG facility will be located. From here river shuttle tankers will export the LNG to Daru where they will load larger export sized tankers for the international LNG market. Horizon has allowed for 3 river carriers and 2 export carriers.

RISC considers the overall estimated CAPEX to be reasonable, however we have some concerns about the LNG transfer and export arrangements, and consider that an alternative scenario with an LNG export facility located at Daru provides a more robust scenario.

We consider that the proposed scheme will require an additional export carrier, and possibly an additional river carrier, to ensure LNG transfer operations do not significantly reduce system availability and performance. The export carriers will be to the cost of the gas offtaker, however they will incur significant demurrage costs due to the river export scheme which will affect the value of the product. To account for this, we have included the demurrage costs in the opex. In addition development planning costs (pre-FID) have been included (Table 8-5).

	CAPEX US$ Million	OPEX US$ Million/year
Development Planning (Pre FID)	50	
Pipeline (Elevala-Mugumugu)	580	
LNG Plant (Barge)	920	40
Other CAPEX	480	5
LNG River Carriers		48
Demurrage on LNG Export Carriers		37
TOTAL Cost	**2030**	**130**

Table 8-5 Gas Export Infrastructure Gross Costs - RISC Estimate

8.3. EXPLORATION

Horizon holds interests in a number of permits in PNG with exploration potential (Figure 8-11).

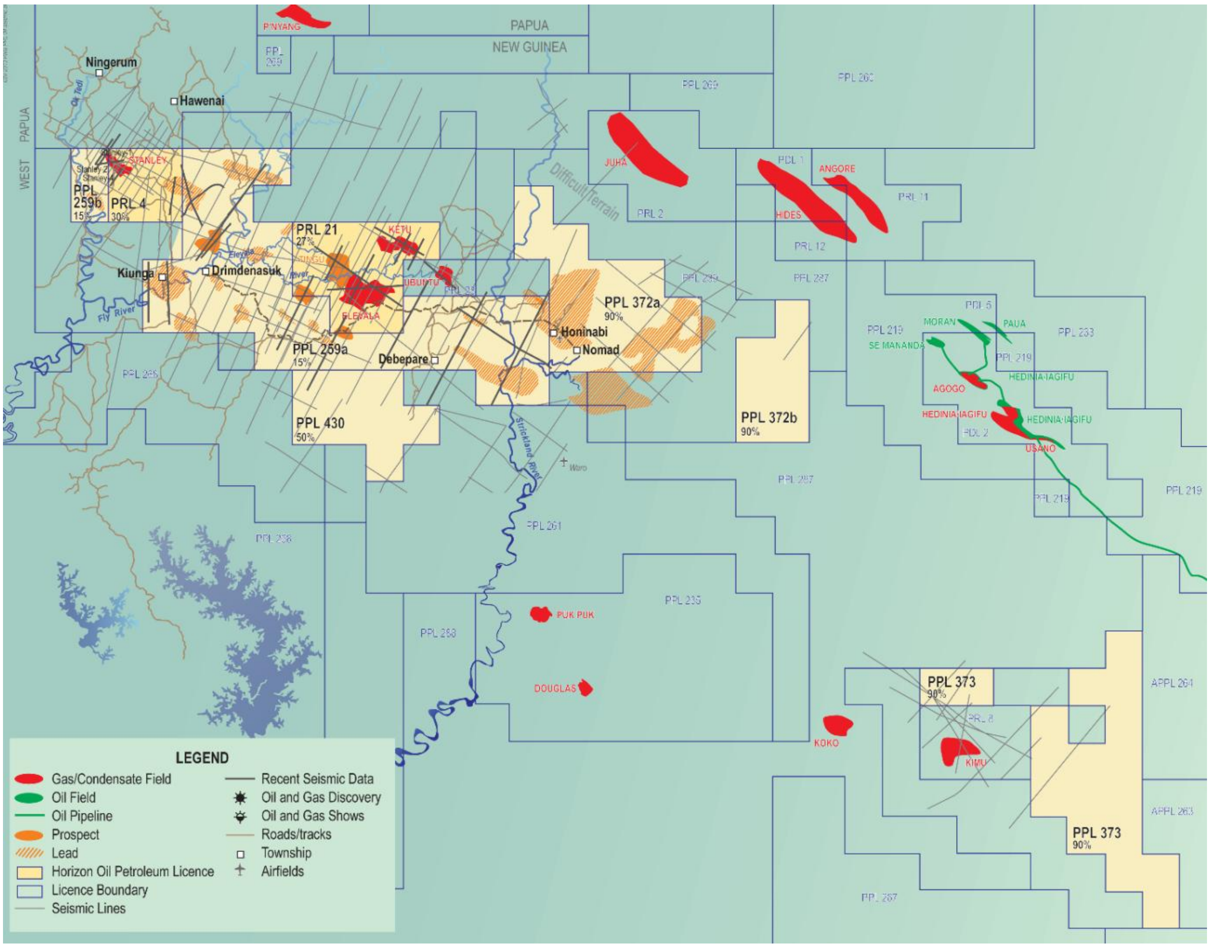


Figure 8-11 Horizon PNG Exploration Acreage

8.3.1. PRL 21

Potential exists in the Toro reservoir below the eastern and western crests of the Elevala Field, termed the Elevala Toro and the Tingu Toro prospects.

The Toro reservoir underlies the Elevala sandstone in the Elevala Field and is likely to underlie the Elevala reservoir in the Tingu Toro Prospect. The Elevala-1 well petrophysical analysis indicates gas saturations in the Toro reservoir, and the pressure readings taken across the reservoir indicate that this section could contain gas, which if the Ketu Field Toro reservoir aquifer pressures were taken into the Elevala Field might have a potential contact at 3,100 mTVDss.

The Toro reservoir has not been tested in either of the Elevala wells, however it was about to be tested in the Elevala-1 well, but the test encountered problems and the test tool was left in the well.

In order to calculate prospective resources for the Toro reservoir, areas were derived from the Toro depth map, supplied by Horizon. The Tingu area was measured with a high case immediately updip from the Tingu-1 well penetration, resulting in a P50 area of 12km^2. The Elevala Toro had 6.5km^2 updip from the wells, which was used as the P90 input and the area of closure to a possible gas-down-to of -3100m (58km^2) was used as the P10 input.

The reservoir parameters were derived from petrophysical analysis. The prospective resource ranges are tabulated below.

Elevala Toro Reservoir Case	Elevala Toro Best Estimate	Tingu Toro Best Estimate	**Total Best Estimate**
GIIP (Bcf)	71	43	**114.0**
Condensate initially in-place (MMbbl)	3.7	2.2	**5.9**
Recoverable Gas (Bcf)	39	23	**62.0**
Recoverable Condensate (MMbbl)	2	1.2	**3.2**

Table 8-6 Tingu Toro Gross Best Estimate Prospective Resources as at 1 January 2014

RISC considers that the Toro reservoir prospects underlying the two culminations in the Elevala Field have a POS of 50%.

Exploration Valuation

There are no further commitments on PRL 21.

The 2014 work program and budget mainly comprises development planning, plus technical costs, and direct costs and community affairs, leading to a budget of $38.4 million.

The low case value assumes the cost of deepening two development wells assuming no farmin promote, so the net value is zero.

The mid case value has been based on a risk adjusted value of the liquids in the 2 prospects of $4 million net to Horizon's 27% interest. The upside case assumes value for both liquids and gas of $20 million.

8.3.2. PPL259

Horizon holds a 35% interest in PPL 259 operated by Eaglewood Energy. PPL 259 lies between the Stanley and Elevala Fields and extends to the southeast of Elevala as shown in Figure 8-12.

The most mature exploration acreage is west PPL 259, where the Nama prospect, shown in Figure 8-12, located on the border between PPL 259 and PRL 4, will be drilled in Q3 2014.

Three further prospects: Herea, Bese and Aongena have been identified as further potential drilling candidates with a total of 180 Bcf (gross) P50 recoverable unrisked gas prospective resources and 6 MMbbl (gross) of condensate.

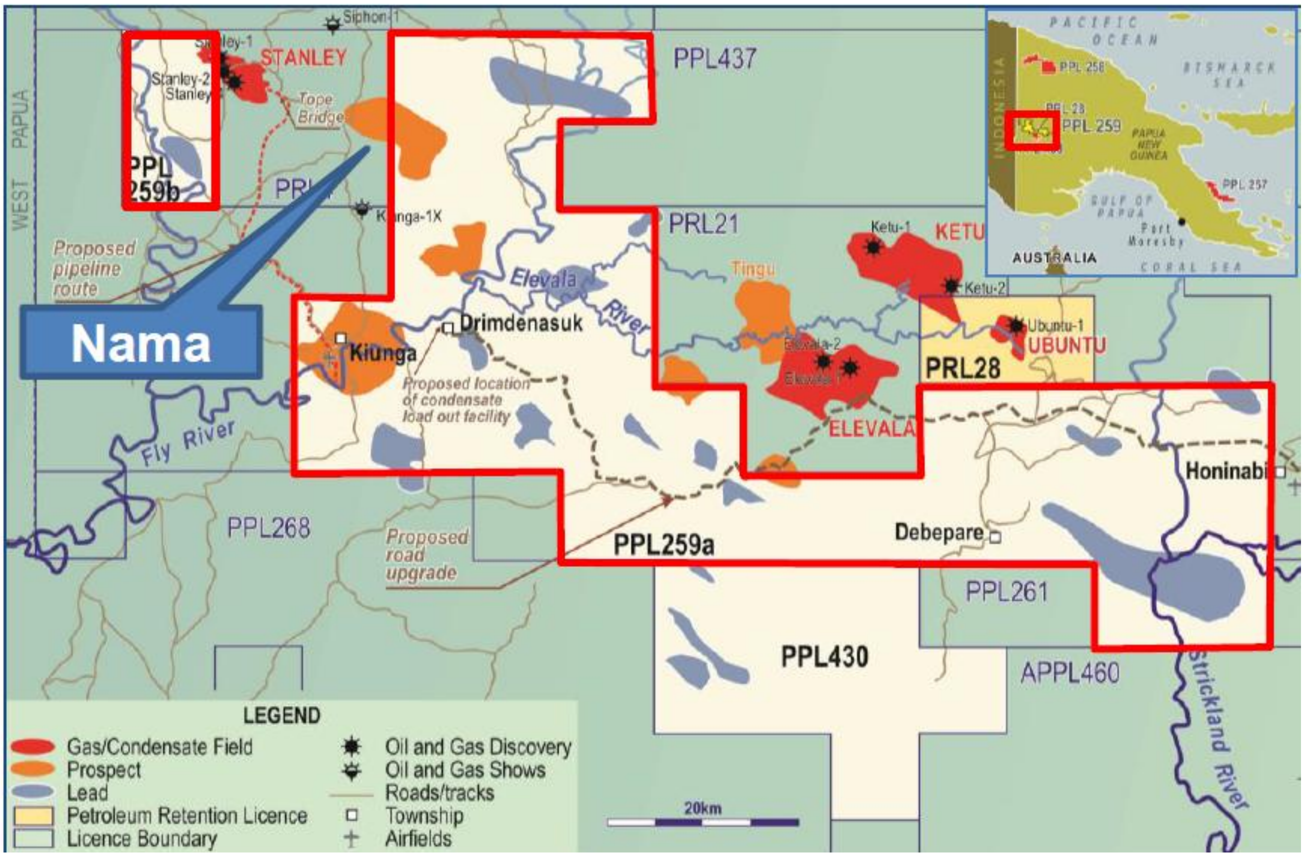


Figure 8-12 PPL 259 Block Location and Prospects

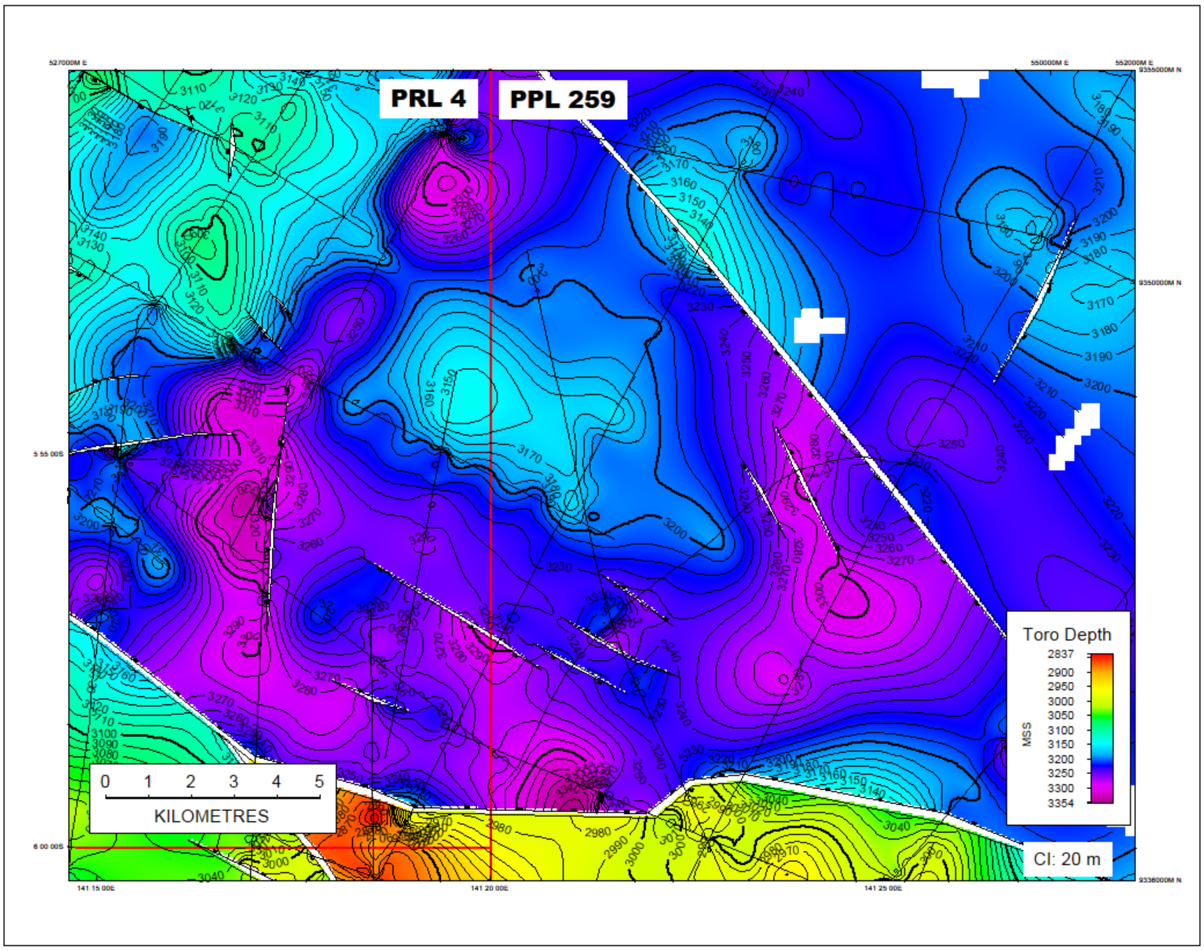


Figure 8-13 PPL 259 Nama Prospect Toro Depth Structure Map

The Nama prospect is defined on four seismic lines of varying vintage and is noted to be a fairly robust structure for which prospective resources have been calculated at the Toro reservoir level, however there is upside potential if either the Elevala or Kimu reservoirs. Eaglewood hold the following prospective resources for the Nama Prospect:

Nama Prospect Case	Best Estimate
GIIP (Bcf)	255
Condensate in Place (MMbbl)	5.4
Recoverable Gas (Bcf)	149
Recoverable Condensate (MMbbl)	2.9

Table 8-7 Nama Prospect Gross Best Estimate Prospective Resources as at 1 January 2014

RISC has independently calculated resource estimates for the Nama prospect and accept the Eaglewood prospective resource estimates above. The prospect is calculated to have a POS of 35%.

A portion of the prospect as mapped potentially lies in PRL4. For the purposes of this evaluation, RISC has not assumed a split as Horizon has comparable interests in PPL 259 and PRL 4 and is therefore the impact on the valuation is not material.

Exploration Valuation

PPL 259 has a seismic and a well commitment for 2014 with a further well to be drilled by 2016.

The technical part of the 2014 budget comprises firm expenditure of $45.4 million.

It is expected that the expenditure for 2015 and 2016 will be in the order of $50 million if a further exploration well is drilled.

Horizon is increasing its interest in PPL 259 by 20% from Eaglewood Energy Inc. by paying a contribution to back costs of $3.75 million and contribution of $5 million to Eaglewood for the next well, a total of $8.75 million for 20%. This values their 35% interest upon completion of the transaction at $15.3 million, which we have adopted as the low and mid fair market value.

The high case valuation has also been calculated on a $/boe basis, resulting in an upside value of another prospect success of $30 million after adjustment for risk, which is incremental to the farmin premium.

8.3.3. PPL 372 and PPL 373

Horizon also holds a 90% interest in PPL 372 and PPL 373, located to the southeast of PPL 259 (Figure 8-11). These permits are in an early stage of exploration.

In respect of PPL 372, the previous operator, Oil Search, identified two large leads in the permit, Honinabi and Mogulu North, on sparse, very poor quality seismic, and gravity and magnetic data.

The 2014 budget for PPL 372 and PPL373 each carry $0.5 million gross for studies and a contingent budget of $4.1 million for 2D seismic.

Horizon carries a fair value of $0.8 million for this transaction which we have adopted as the fair market value.

8.3.4. PPL 430

Horizon holds a 50% interest in PPL 430, located to the south of PPL 259. This permit is in an early stage of exploration, and as yet contains leads only.

License PPL 430 was awarded to Horizon (as Ketu Petroleum Ltd) and Eaglewood Energy each partner holding 50% on 25 July 2013.The firm commitment over the first two years of the licence is as follows:

- Data Collection and Analysis
- Sources and Migration Studies
- Geological Studies
- Seismic Reprocessing
- Seismic Acquisition (approximately 20km) and interpretation.

These are to be completed at a cost of no less than US$1.0 million

The 2014 firm work program comprises technical costs and community relations with a budget of $550,000 with a contingent work program of 50 km of 2D seismic acquisition at a total budget of $4.6 million.

The gross expenditure on PPL 430 will range from the commitment of US$1 million to the firm plus contingent exploration program of US$4.9 million.

We have assigned a value of $0.5 million for Horizon's interest in the high case in this permit based on the value of the permit commitment.

8.3.5. PNG Exploration Value Summary

A summary of the PNG exploration fair market value is shown in Table 8-8.

Permit	Low US$ million	Mid US$ million	High US$ million
PRL 21	0.0	4.0	20.0
PPL 259	15.3	15.3	45.0
PPL 372 and 373	0.8	0.8	0.8
PPL 430	0.0	0.0	0.5
Total	**16.1**	**20.1**	**66.3**

Table 8-8 PNG Exploration Fair Market Value - Net Horizon Working Interest

9. MALAYSIA

9.1. D35/ J4/ D21

9.1.1. Field description

In April 2014, Roc announced a farm-in for a 50% participating interest in the D35/D21/J4 fields. Roc has subsequently reported the intention to farm-out a 20% participating interest, subject to PETRONAS approval.

The farm-in agreement includes amendments to the existing PSC effective from 1 January 2014 until December 2034. The PSC terms are designed for field redevelopment and enhanced oil recovery (EOR) to commercially encourage progressive incremental oil development over the full life of the PSC.

Geologically, the fields lie within the western Balingian province of the Sarawak Basin. The fields are located on the continental shelf offshore Eastern Malaysia within a licence area of 150 km2, in water depths of approximately 50 m. D35 is the largest of the three fields with the longest production history and represents a significant brownfield redevelopment project. Within the D35 field boundary, there is evidence of significant appraisal and near-field exploration potential. J4 and D21 are satellite producing assets with similar potential and together they comprise the D35, D21 and J4 PSC.

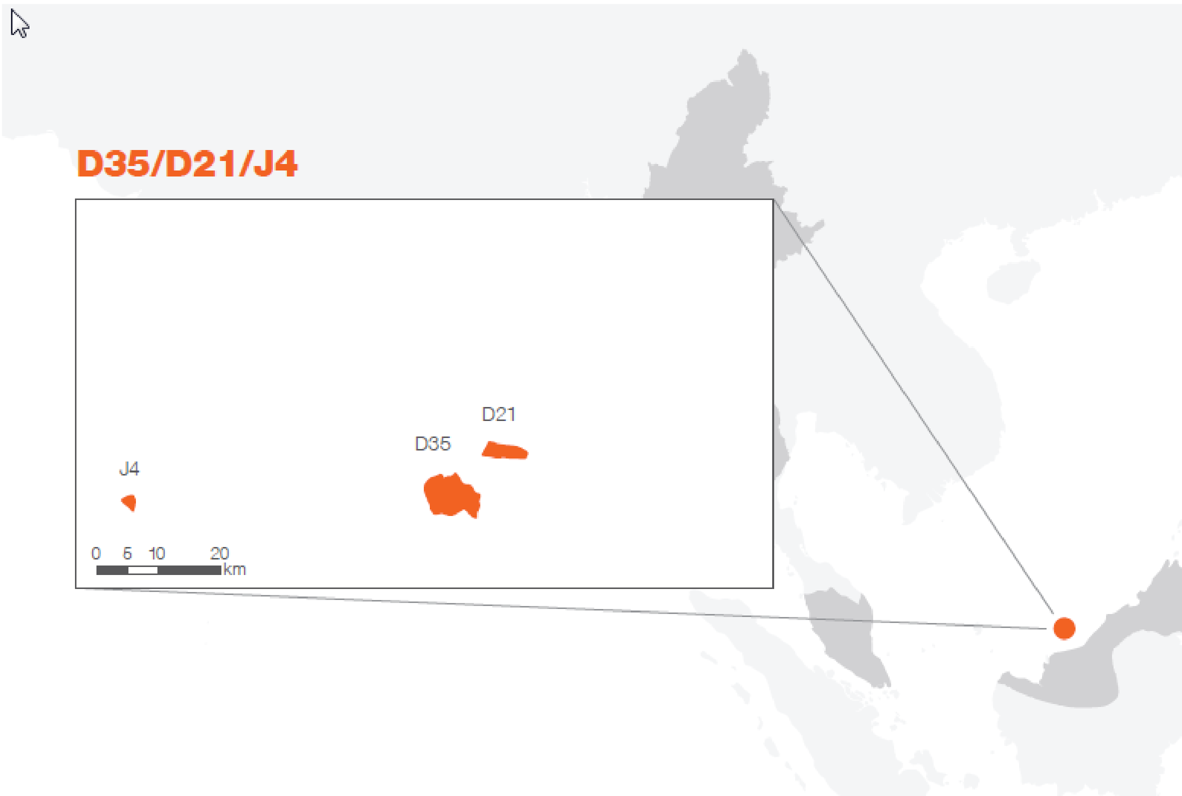


Figure 9-1 Location Map – Malaysian Fields, offshore Sarawak

In March 2014, the fields are currently producing 9,914 stb/d of oil (3,979 bbl/d from D35, 3,815 from J4 and 2,120 from D21). Roc has estimated that D35 contains a STOIIP in the range of 400-736 MMstb in the major and minor reservoirs plus further gas resources that are under review. Cumulative production to end 2013 is estimated at 86.6 MMstb of oil and 260 bcf of gas. RISC has not included structure maps in the report as they are deemed commercially sensitive.

In J4, Roc estimates a STOIIP of 41-117 MMstb with 67-183 bcf associated and solution gas. Cumulative production to end 2013 is estimated at approximately 12.2 MMstb of oil and 11.3 bcf of gas.

In D21, Roc estimates a STOIIP of 34-80 MMstb with 102-151 bcf of associated, non-associated and solution GIIP in the Cycle II reservoirs. Cumulative production to end 2013 is estimated at approximately 0.6 MMstb of oil and 0.6 bcf of gas.

The estimates presented herein should not be construed as being estimates supported by PETRONAS.

9.1.2. Production forecast

D35 and J4 are mature fields with established production history whereas D21 came onstream in 2013. D35 came onstream in 1994 and is located in 47m of water.

9.1.2.1. Development description

Roc's plans to redevelop the fields entail a number of progressive stages:

SPE PRMS Category	Activity Description
Reserves	Arrest the decline of existing well stock and undertake a number of production enhancement activities including new wells
Contingent Resources	Additional wells and sidetracks contributing incremental oil production and water flood in the major reservoirs
	Introduction of EOR techniques
	Water flood in the minor reservoirs

Table 9-1 D35/J4/D21 further development stages

Roc's forecast oil production for the successive stages is illustrated in Figure 9-2.

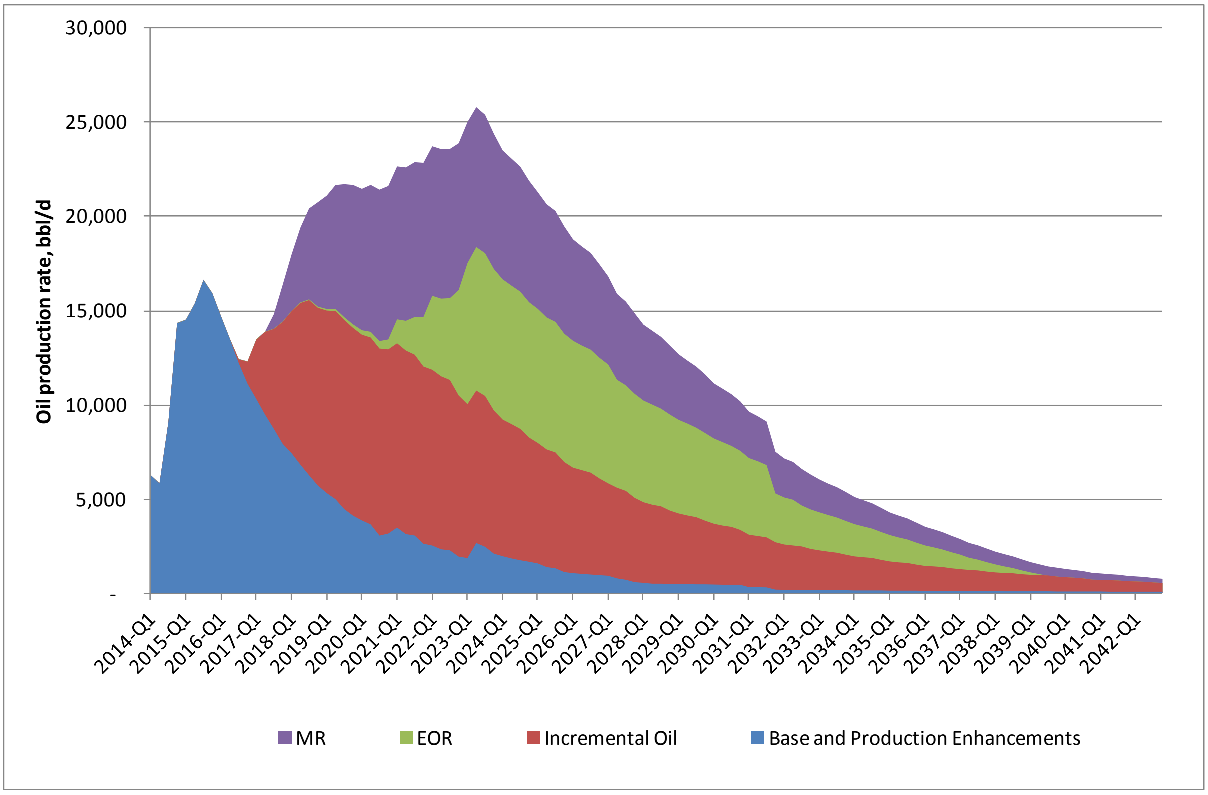


Figure 9-2 Gross oil production forecast, D35/J4/D21- Roc estimates

D35 is a 'hub' field with the largest infrastructure consisting of a central processing platform, 3 wellhead platforms, an accommodation and a riser platform. Oil export and gas export pipelines, connect the hub to shore.

Roc proposes a significant redevelopment of the field. Initially this will consist of wireline interventions, workovers and sidetracks from existing wells as well as drilling. The minimum work commitment is in 2 parts. Part 1 consists of the drilling of wells, 1 workover and preparation and submission of a redevelopment FDP. Part 2, subject to FID, consists of drilling more wells and the implementation of water injection, application of EOR and, upon success, extension of water injection to the minor reservoirs.

J4 consists of a wellhead platform with well test facilities tied back to D35 via a multiphase pipeline. Short term remedial activities consist of wireline work (mainly reperforations) and facilities rejuvenation. The Contingent Resources consist of a sidetrack and further work is anticipated.

D21 consists of wellhead platform with well test facilities tied back to D35 via a multiphase pipeline. The Contingent Resources of D21 consist of a development well, a recompletion, sidetrack and reperforations. An exploration well is also part of the proposed activity.

Roc's reserve and resource estimates

Roc's reserves and resource estimates are shown in Table 9-2 allocated according to the recovery expected from future development activities. RISC has evaluated the reserves and resources at field and reservoir level but for reasons of commercial sensitivity has been requested to report aggregate PSC level quantities.

RISC has reviewed and supports the 2P Reserve and the incremental oil estimates subject to a further risk adjustment for the waterflood portion of the incremental oil. The EOR and minor reservoir incremental estimates have little definition at present and will be subject to the successful implementation of the incremental oil portion of the Contingent Resources. The EOR and minor reservoir estimates have not been risk adjusted.

Product	Production 31/12/2013	2P Reserve			2C Contingent Resource			
		Total	Base	Production Enhancement	Total	Incremental Oil	EOR	Minor Reservoirs
Oil MMstb	99.4	27.6	11.6	16.0	96.0	40.0	24.5	31.5
Gas Bcf prod/sales	272.1/222.1	42.9	41.7	1.2	71.9	71.9	0.0	0.0
Note: Roc's working interest is 30% subject to finalisation of PETRONAS approval. Under PRMS guidelines, Roc's reserve and resource entitlement is determined by their net economic interest which is a function of the PSC terms, costs and prices prevailing during the PSC term. Depending on these factors, there may be a material difference between the working interest and Roc's net economic interest.								

Table 9-2 D35/J4/D21 Gross Reserves and Resources - Roc estimates as at 1 January 2014

Based on recent production performance, RISC has projected that there has been a further depletion of approximately 1 MMstb and 4 bcf gross from the period 1 January 2014 to 31 March 2014. The actual production during this period has yet to be confirmed.

Base and production enhancement activities

Roc is forecasting oil recovery of 27.6 MMbbl gross from the existing field decline (11.6 MMbbl) and production enhancements (16 MMbbl). RISC considers that this is a reasonable total overall.

The three fields are currently producing approximately 10,000 bbl/d of oil, the production enhancement activities target an increase to approximately 17,000 bbl/d. Based on the production decline, RISC considers that the existing producers will recover the 11.6 MMbbl, which is a conservative estimate.

i. Incremental recovery from existing wells

RISC has undertaken a comprehensive review of logs for all gas and oil 'behind-pipe' opportunities in D35 for recompletion in the existing wells. In aggregate, RISC believes the Roc assessment is reasonable.

ii. Acceleration projects

There are a number of opportunities to accelerate production from sands in D35 that have already produced in the existing wells from activities such as reperforation and acidizing. Whilst the acceleration activities do not contribute substantially to the recovered volumes. RISC estimates rate improvements in excess of 2,000 bbl/d.

iii. Drilling activities

RISC has reviewed Roc's proposed infill drilling locations for D35 and has also independently generated infill drilling locations and recovery.

We note that there are risks to these infill well volumes and incremental projects, e.g. the sands have been pressure-depleted due to production from adjacent wells (which will reduce recovery factor and initial productivity), and that the GOC in each sand has expanded to below the depth of intersection due to pressure depletion (causing gas to be intersected rather than oil, reducing ultimate recovery). The production enhancement activities have accounted for the perceived technical risks.

RISC has not reviewed the production enhancement activities identified by Roc for J4, however, activities of a similar nature to those in D35 are expected. Overall a slightly conservative production forecast from the existing D35/J4/D21 wells negates the need to risk the J4 activities.

Incremental oil production activities

i. **Water injection**

These planned activities require a major investment in re-development through water flood designed to re-pressurize and sweep remaining oil accumulations and possible EOR applications that may further increase recovered volumes.

RISC has reviewed of the potential recovery following water injection into the D35 field and supports Roc's estimate as an unrisked estimate of additional recovery from the application of water injection in the major reservoirs.

However, RISC notes that there are a number of characteristics of the D35 field that are potentially detrimental to efficient water flood:

- reservoir compartmentalisation - the field has a significant compartmentalisation, probably more than recognised by current mapping. Compartmentalisation is important in determining the location of water injection wells and the flow path of injected water; and
- some target reservoirs show a degree of vertical stratification.

Whilst neither of these factors precludes water injection they will result is some loss of efficiency which could lead to reduced recovery or additional costs.

RISC has estimated the incremental oil production rate from successful water injection estimated is 6,500 bbl/d in the mid case (unrisked). Roc will carry out studies and injection pilots before proceeding to full scale water injection. At this stage, there is uncertainty in the scope and conformance of the waterflood and we recommend risking the water injection project by 50%.

ii. **Further infill drilling**

RISC has reviewed the possible locations for additional drainage points targeting the minor reservoirs and considers additional recovery is achievable. RISC has not evaluated the economics of these wells.

Compartmentalisation of the minor reservoirs, both structural and stratigraphic, heightens the development risk in these reservoirs.

If the minor reservoirs are developed, the additional penetrations through the major sands will increase the chance of success of the water flood.

In aggregate, we recommend applying a technical risk factor of 70% to the Incremental Oil Contingent Resource.

EOR

Roc has considered the possible application of enhanced oil recovery (EOR) techniques to further the production from the field. EOR is a complex area of study and has not been addressed in detail other than to relate a possible EOR benefit to the produced water profile of the incremental oil. Roc has noted that typically, successful EOR projects can increase recovery by 10% in the swept areas of the reservoir. Roc estimates that the application of EOR techniques to suitable reservoirs could increase recovery by 10% and ascribes an additional 24.5 MMbbl recoverable. RISC has not quantified an EOR estimate but notes that the estimate appears high.

At this stage of development the EOR project is conceptual and dependent on results in the major reservoir waterflood project, which has yet to be demonstrated and we recommend applying a technical risk factor of not greater than 25%.

Minor reservoirs (MR)

Further primary development of the minor reservoirs has been considered in detail by RISC and is included in incremental oil activities. Roc has, in addition, indicated the possible introduction of water injection to these (minor) reservoirs for an additional 31.5 MMbbl recovery. Targeting these reservoirs will benefit from additional knowledge gained from earlier infill and water injection wells drilled to the main reservoirs.

At this stage of development the minor reservoir project is conceptual and dependent on results in the major reservoir waterflood project, which has yet to be demonstrated. There is also increased risk of lateral discontinuities in the minor reservoirs and we recommend applying a technical risk factor of not greater than 25%.

9.1.3. Capital and operating cost forecast

Roc estimate base case costs of $75 million for the D35/D21/J4 fields, this is mostly for D35 ($61 million) with small components for the other fields.

Capital Costs

Roc estimate base and production enhancement capital costs totaling $206m for the initial redevelopment of the 3 fields. This total includes $35 million for two exploration wells in the D35 field and $10.5 million for re-perforations in the J4. The remainder of the costs are for remedial well work, new wells and a new platform in the D35 field.

Costs for incremental oil activities will depend on the results of the FEED study and pilot water injection pilot but are estimated to be $837 million. This is mostly for additional facilities that will be required for water injection and water handling as well as new platforms and over 30 new wells. See Table 9-3 below for Capex breakdown.

It should be noted that the costs (and resources) for the incremental oil, EOR and minor reservoir projects are based on the assumption of a conceptual full field implementation. As discussed above the scope and benefit of these projects has yet to be finalised. It is not expected that the full capital would need to be deployed under the risked scenario.

US$ million RT 2014	Base	Base and Production Enhancement	Incremental Oil	EOR	MR
D35	61	195	760	20	296
D21	2		55		
J4	12	11	21		
Total	75	206	836	20	296

Table 9-3 D35/D21/J4 Gross Capex Summary – Roc estimates

All costs include 17% contingency.

Abandonment Costs

The abandonment costs for the fields have been provided by Roc and are summarised below. RISC believes that these costs are reasonable.

Project	Abandonment Costs (US$ million RT 2014)
Base + Production Enhancement	50
Incremental Oil	80
EOR	0
MR	9.1

Table 9-4 Gross Abandonment Cost Summary – Roc estimates

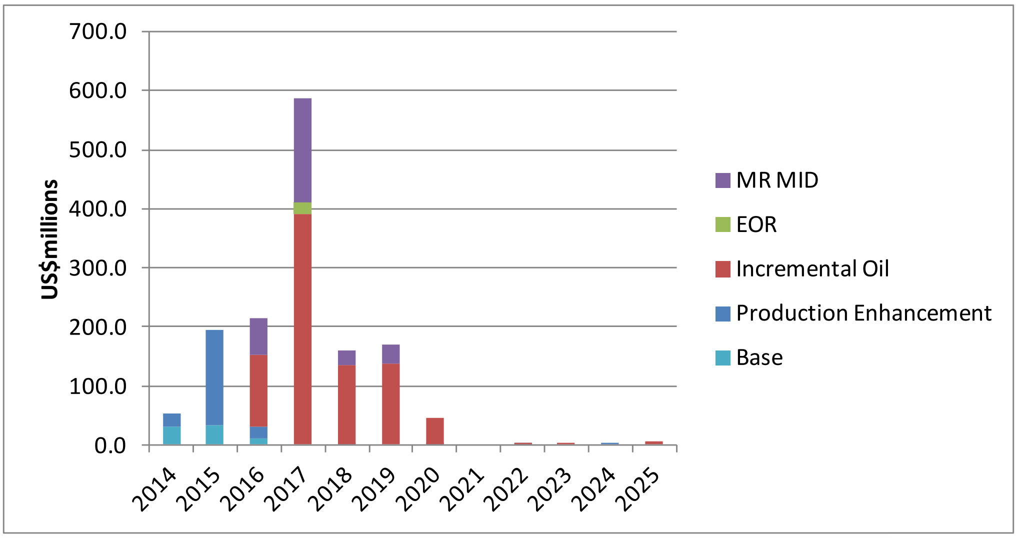


Figure 9-3 D35/D21/J4 Gross Capex Phasing – Roc estimates

Operating Costs

Due to limitations on the availability of cost data, Roc have estimated operating costs based on their experience rather than actual historical data.

The costs for the base case +production enhancement vary from $100 million to $75 million p.a. gross and then are steady in real terms after 2018. The increase related to incremental oil is from $12-18 million p.a. gross, the EOR increment is $5-6 million p.a. and the MR increment is $10 million p.a gross. These costs appear reasonable to RISC. See chart below for a summary of the costs.

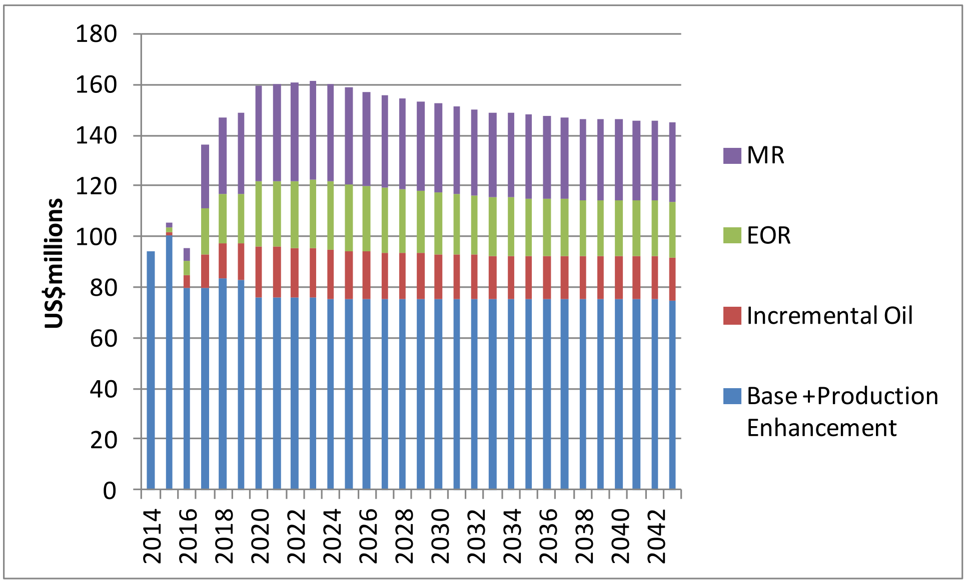


Figure 9-4 D35/D21/J4 Gross Opex Phasing – Roc estimates

9.2. BALAI CLUSTER

RISC did not carry out a technical review of the Balai Cluster Risked Service Contract. The Capex recovery profile has been assessed by the Independent Expert.

9.3. EXPLORATION

Roc has reviewed leads and prospects that had been identified in the vicinity of the D35 Field. We note the work of developing leads is at an early stage and further work on prospect risking and ranking will be undertaken.

RISC has not conducted its own independent review of the inventory and therefore we are not in a position to comment on the robustness of the technical interpretation. We note that about half of the leads are small and would not be justified for drilling on present volumetrics and risking. We have estimated the value of the exploration portfolio based on the information provided by Roc and made an adjustment for a notional drillable portfolio that could potentially materialise. We believe that 3-5 MMbbl (risked, Roc 30% working interest) of exploration potential could mature in a reasonable time frame.

Although dependent upon further review of the 3D seismic, Roc is sufficiently encouraged to suggest an exploration program to mature these prospects and leads. The notional program includes:

• One (1) Firm Exploration well

• One (1) Contingent Exploration well OR seismic work program

The net cost of the work program for Roc's 30% working interest is estimated to be $10.5 million.

In the low and mid cases, we have valued the exploration potential based on the work program and a notional farmin promote. In the low case, we have assumed that there is no promote. In the mid case, we have assumed a farmin partner could be attracted on the basis of a 2:1 promote. In the high case, we have recognised the potentially attractive nature of the near-field exploration and have assigned value based on prospective resources of 4 MMbbl Roc net working interest which after risk adjustment provides an expected monetary value (EMV) of $8 million incremental to the mid case farmin promote. RISC's estimates of fair market value is shown in Table 9-5.

Low US$ million	Mid US$ million	High US$ million
0	10.5	18.5

Table 9-5 Malaysia D35 Exploration Fair Market Value - Net Roc Working Interest

10. MYANMAR

In March Roc was notified by the Myanmar Ministry of Energy (MOE) of the successful award of a PSC for a shallow water Block, M7, in the Moattama basin, offshore Myanmar (Figure 10-1).

The PSC award is subject to finalisation of terms with the MOE and Roc Board approval. Roc will hold a 59.375% interest and operate the licence. The other partners are Tap Oil 35.625% and Smart E&P International Ltd 5% carried interest.

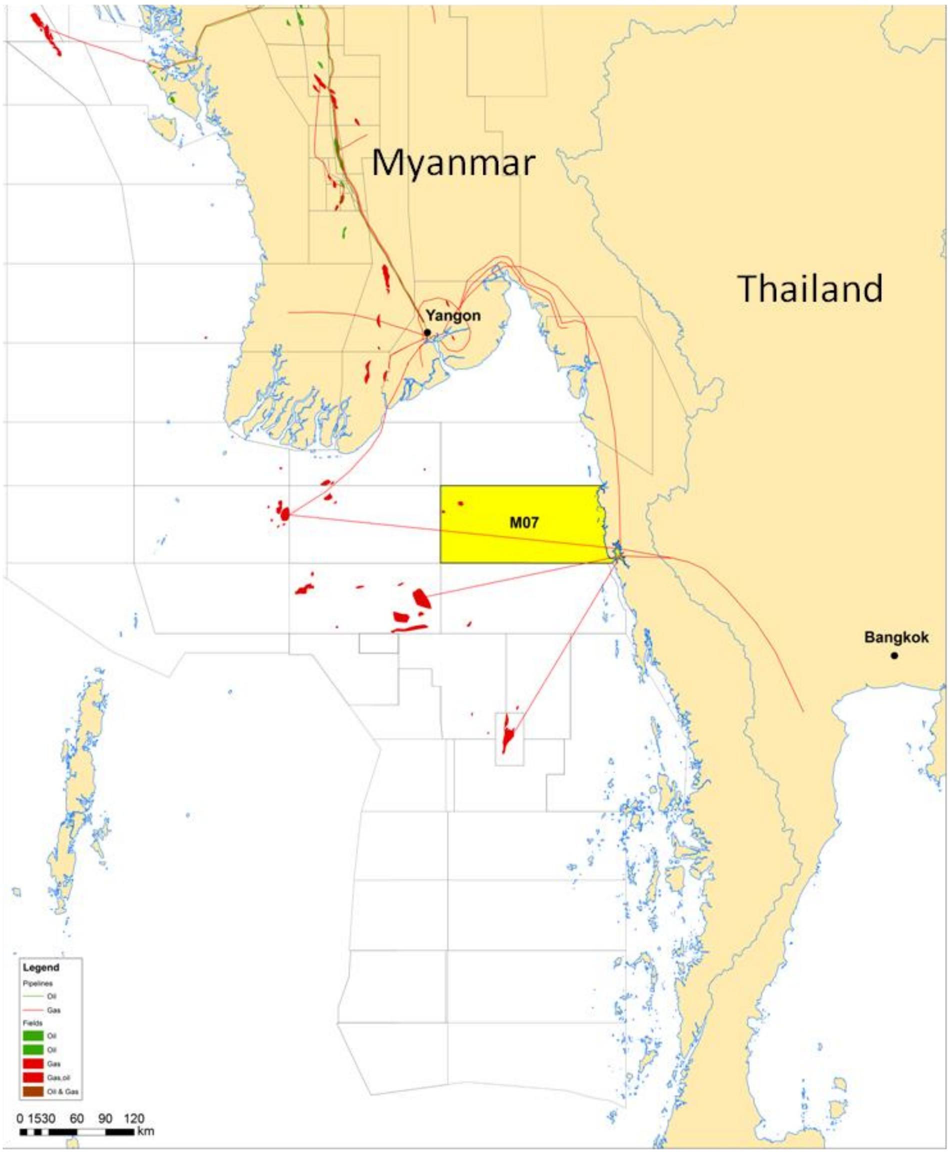


Figure 10-1 Myanmar Block M7 Location Map

The block award includes a provision for the JV to undertake an 18 month study of the existing seismic and well data which Roc are hoping to get from the MOE and an Environmental Impact Assessment. After this period the JV has the option to pay the signature bonus and enter into a three year exploration work program. Roc will pay 62.5% which includes a 3.125% share of the carry of Smart E&P International, its local partner.

RISC has reviewed the work program and considers it to be reasonable. The details of the bid programme is commercially confidential and is not disclosed in this report.

Block M7 covers approximately 13,000km2 and is 160 km east of the 6.7 Tcf GIIP Yadana gas field and 110km north east of the Zawtika biogenic gas field where reserves range from 435 Bcf to 2Tcf in multiple fault bounded Mio Pliocene delta front sandstones. The latter is consistent with the type of play in M7 however to date only two small uneconomic discoveries have been made in M7 in wells M-07-2 and Janaka-1. There are two other dry holes in the block and a reasonable grid of legacy 2D data.

Prospectivity in the block may be limited to the western side of the Sagaing Fault Zone (M7 West zone Figure 10-2) where the two small gas discoveries have been made. The area is highly faulted creating multiple small structures.

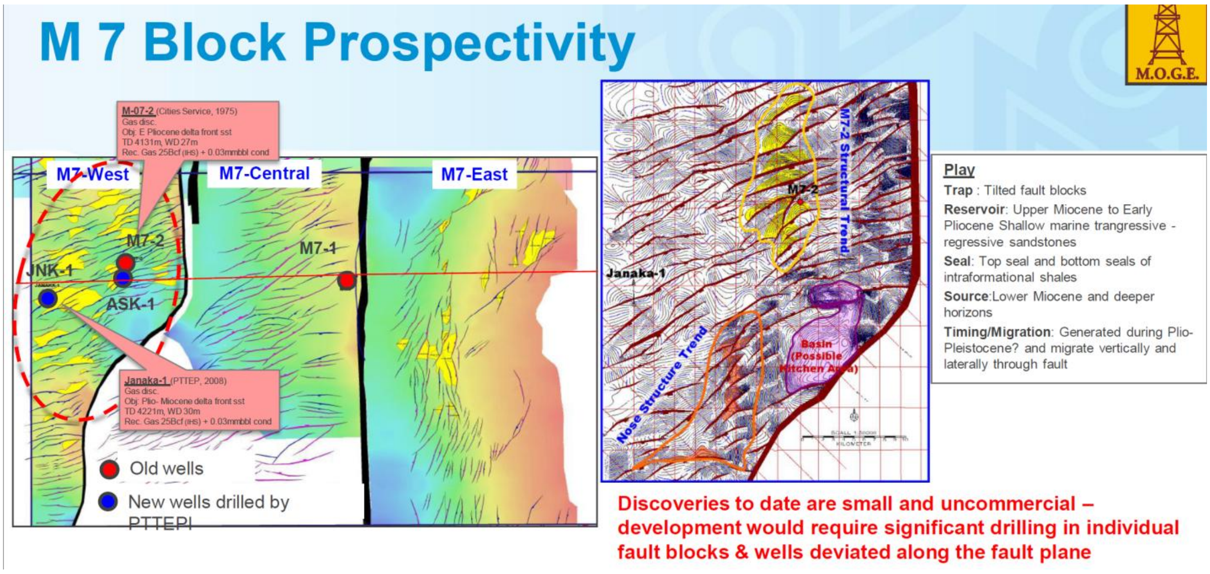


Figure 10-2 M7 Block Prospectivity

Due to the early stage of exploration in the block, we have valued the permit based on the value of the work program, which is estimated to be $2.75 million for the initial 18 months ($ 1.72 million net to Roc).

In the low case, we have not assigned a premium value so the net fair market value of the block is zero.

In the mid and high cases, value for this block might be crystallised by Roc farming down their interest for a carry on their initial period costs of $1.7 million on a 2:1 promote, therefore valuing their interest at $0 to $1.7 million (Table 10-1).

Low US$ million	Mid US$ million	High US$ million
0	1.7	1.7

Table 10-1 Myanmar M7 Block Exploration Fair Market Value - Net Roc Working Interest

11. DECLARATIONS

11.1. 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.

11.2. RELIANCE

This Report is to be relied upon by Deloitte Corporate Finance Pty Limited (Deloitte) acting as the Independent Expert. RISC Operations Pty Ltd (RISC) acknowledges that the Deloitte and the Directors of Horizon Oil Limited (Horizon) will use and place reliance on this Report in evaluating the proposed merger with Roc Oil Company Limited (Roc).

11.3. VALMIN CODE

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").

11.4. 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).

11.5. REPORT TO BE PRESENTED IN ITS ENTIRETY

RISC has been advised by Horizon that this report will be presented in its entirety without summarisation.

11.6. 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 Horizon and Deloitte and confirms that there is no conflict of interest with any party involved in the assignment;
- Under the terms of engagement between RISC and Deloitte for the provision of this report RISC will receive a fee, based on time expended and our current standard terms and conditions, payable by Deloitte. The payment of this fee is not contingent on the outcome of any transaction between Deloitte, Horizon, Roc and other party;
- The Directors and staff of RISC involved in the preparation of this report hold no interest in Deloitte, Horizon or Roc.

11.7. 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 Deloitte, Roc and Horizon 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 Horizon and Roc 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). 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.

11.8. CONSENT

RISC has consented to this report, in the form and context in which it appears, being included in the Scheme of Arrangement for Horizon Oil Limited. 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 13 June 2014.

Geoffrey J Barker
Partner

12. LIST OF TERMS

The following lists, along with a brief definition, abbreviated terms 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

Abbreviation	Definition
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
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	Economic 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

Abbreviation	Definition
FM	Formation
FPSO	Floating Production Storage and offtake unit
FWL	Free Water Level
FVF	Formation volume factor
GIIP	Gas Initially In Place
GJ	Giga (109) 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
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

Abbreviation	Definition
m	Metres
Marathon	Marathon Oil Corporation
MDT	Modular dynamic (formation) tester
mD	Millidarcies (permeability)
MJ	Mega (106) 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 (106) 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

Abbreviation	Definition
	(1P), Proved + Probable (2P) and Proved + Probable + Possible (3P) confidence levels respectively.
PBU	Pressure build-up
PJ	Peta (1015) Joules
POS	Probability of Success
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

Abbreviation	Definition
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
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

Abbreviation	Definition
Tcf	Trillion (1012) cubic feet
TJ	Tera (1012) 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

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DECISIONS WITH CONFIDENCE

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