16 June 2014

ASX RELEASE

INDEPENDENT EXPERT'S REPORT

ROC recently commissioned Grant Samuel & Associates Pty Ltd to prepare an Independent Expert's Report on the proposed merger with Horizon Oil.

The Independent Expert has concluded that the merger is in the best interests of ROC shareholders.

ROC shareholders will have recently received a Notice of an Extraordinary General Meeting to be held on 11 July 2014 (**EGM**). The meeting has been requested by fund manager Allan Gray to consider a resolution to change ROC's Constitution and to frustrate the Merger. The Board's view is that this is clearly not in the best interests of ROC shareholders.

ROC's directors unanimously recommend that ROC shareholders VOTE AGAINST the resolution proposed at the EGM enabling the merger with Horizon Oil to proceed.

A copy of the Independent Expert's Report and a summary prepared by Grant Samuel are attached to this announcement. Copies of these documents are also available on ROC's website at http://www.rocoil.com.au/Investor--Media-Centre/Announcements/.

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15 June 2014

The Directors
Roc Oil Company Limited
Level 18, 321 Kent Street
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Dear Directors

Proposed Merger with Horizon Oil Limited

1 Introduction

On 29 April 2014, Roc Oil Company Limited ("ROC") and Horizon Oil Limited ("Horizon") announced that they had reached agreement for a "merger of equals" ("Merger"), to be effected via a scheme of arrangement between Horizon and its shareholders ("Scheme"). Under the Scheme, Horizon shareholders will receive 0.724 ROC shares for each Horizon share held. As a result, Horizon shareholders will hold approximately 58% of the shares in the merged company ("New ROC"), while ROC shareholders will hold the remaining 42%. The Scheme requires Horizon shareholder approval.

ROC and Horizon are Australian oil and gas companies, with assets across a range of countries including the People's Republic of China ("China"), Papua New Guinea ("PNG"), Malaysia and New Zealand. Shares in ROC and Horizon are listed on the Australian Securities Exchange ("ASX"). Immediately before the announcement of the Merger, ROC had a market capitalisation of $315 million, while Horizon's market capitalisation was $480 million. ROC's major assets are interests in producing Beibu Gulf fields, offshore China ("Beibu Gulf Joint Venture"); interests in producing Bohai Bay fields, offshore China ("Zhao Dong Joint Venture"); and certain Malaysian interests. Horizon's major assets are interests in the Beibu Gulf Joint Venture; an interest in the producing Maari/Manaia oilfields in the offshore Taranaki Basin, New Zealand; and exploration and development projects in the Foreland Basin in western PNG.

There is no statutory or other regulatory requirement for ROC to commission an expert's report in relation to the Merger. Nevertheless, the Directors of ROC have engaged Grant Samuel & Associates Pty Limited ("Grant Samuel") to prepare an independent expert's report setting out whether, in its opinion, the Merger is in the best interests of ROC shareholders. A copy of the report is to be released to the ASX and made available on ROC's website. It will also be available on request to ROC shareholders. This letter contains a summary of Grant Samuel's opinion and main conclusions.

In this letter, dollar amounts relate to United States dollars unless otherwise specified.

2 Summary of Opinion

In Grant Samuel's opinion, the terms of the Merger are fair to ROC shareholders. The Merger benefits are collectively significant and outweigh the disadvantages. Accordingly, the Merger is in the best interests of ROC shareholders.

On the basis of sharemarket values and Grant Samuel's assessment of the full underlying values of ROC and Horizon, the aggregate interest of ROC shareholders in New ROC will be approximately proportionate to ROC's contribution of value to the merged company. The terms of the Merger are therefore fair to ROC shareholders.

It should be recognised that estimates of value of the assets of ROC and Horizon are inherently uncertain. Estimates of value of oil and gas assets (and particularly development and exploration assets) can change relatively quickly, potentially by material amounts, and are dependent upon such factors as future oil prices, development progress and appraisal and exploration success. In particular, Horizon's PNG development assets represent a material proportion of Horizon's overall value. A relatively wide range of development outcomes (and therefore values) for these assets is credible. Judgements regarding the current value of these assets are subjective.

Relative to Horizon, the value of ROC is less sensitive to movements in oil prices, as ROC held significant cash at 31 December 2013 (representing approximately 18% of its market capitalisation prior to announcement of the Merger) while Horizon had net debt. Similarly, ROC is probably less exposed to changes in overall market sentiment towards the oil and gas sector.

Accordingly, while Grant Samuel believes that the terms of the Merger are fair to ROC shareholders, this conclusion could change for different market conditions. In particular, the Merger terms would become less attractive for ROC shareholders if oil prices were to fall materially or if the PNG investment environment was to significantly deteriorate.

The Merger offers a number of benefits for ROC shareholders. New ROC will be a much larger company than ROC on a standalone basis and its shares should enjoy significantly greater liquidity. New ROC should be able to access both equity and debt capital on more attractive terms than those available to ROC on a standalone basis. New ROC will have a broader array of assets within a geographically more diversified asset portfolio (although some shareholders may prefer to achieve this diversification directly through their own investment decisions). While merger synergies are not expected to be material, it is likely that some corporate cost reductions will be achieved.

Importantly, the Merger will provide ROC with significant growth options. ROC on a standalone basis has relatively limited opportunities for growth (notwithstanding its recent farm in to a production sharing contract offshore Malaysia). Its asset portfolio largely consists of producing assets that are approaching or in production decline. By comparison, Horizon's PNG assets have the potential to deliver substantial production growth in the medium term and offer considerable "blue sky" upside beyond that. More generally, the size and enhanced financial flexibility of New ROC should give it the capacity to consider larger and potentially riskier acquisitions, developments or other growth initiatives than would have been appropriate for ROC on a standalone basis.

All these factors suggest that there is a realistic prospect that the Merger will result in a market re-rating of New ROC. In this regard, ROC shares are trading at prices approximately 25% higher than immediately before the announcement of the Merger, while the combined market capitalisation of ROC and Horizon has grown by around 18%[1] since the announcement of the Merger. While the potential for a market re-rating is generally difficult to quantify, the share price performance of both ROC and Horizon since the announcement of the Merger suggests that the re-rating opportunity is significant. ROC (and Horizon) shareholders would stand to lose the recent share price appreciation if the Merger did not proceed.

Moreover, ROC shareholders will not give up the opportunity to realise a full premium for control at some later stage. While ROC shareholders will in aggregate represent a minority (42%) in New ROC, the Merger will not result in passing of control in the sense of the acquisition of a controlling shareholding by any single shareholder. The share register of New ROC will arguably be more open than the current ROC register, with no shareholder holding more than 14%[2] of New ROC. ROC shareholders will retain an opportunity to realise a full premium through a subsequent change of control transaction for New ROC. On one view the prospects of such a transaction should be enhanced, given the upside potential, ultimate scale and corporate appeal of the PNG assets.

1 Based on the Horizon share price on 22 April 2014.

2 Based on substantial shareholder notices to 13 June 2014.

ROC shareholders should understand that the Merger will change the investment characteristics of their holdings. In essence, relative to ROC on a standalone basis, New ROC will have greater growth opportunities but will face additional development and other risks. In the short to medium term at least, New ROC is likely to have lower free cash flows, given the need to fund the development of its PNG assets, although successful development of the PNG assets would deliver material growth in earnings and free cash flows in the longer term. The market response to the Merger announcement and Grant Samuel's valuation analysis suggests that the net effect of these changes is broadly neutral or potentially marginally positive from a short term value perspective. However, it would clearly be open to investors with different risk appetites or a focus on short term earnings versus longer term growth to take a different view on the net benefit to ROC shareholders.

In Grant Samuel's opinion, the Merger benefits are collectively significant and outweigh the disadvantages. The Merger is in the best interests of ROC shareholders.

3 Key Conclusions

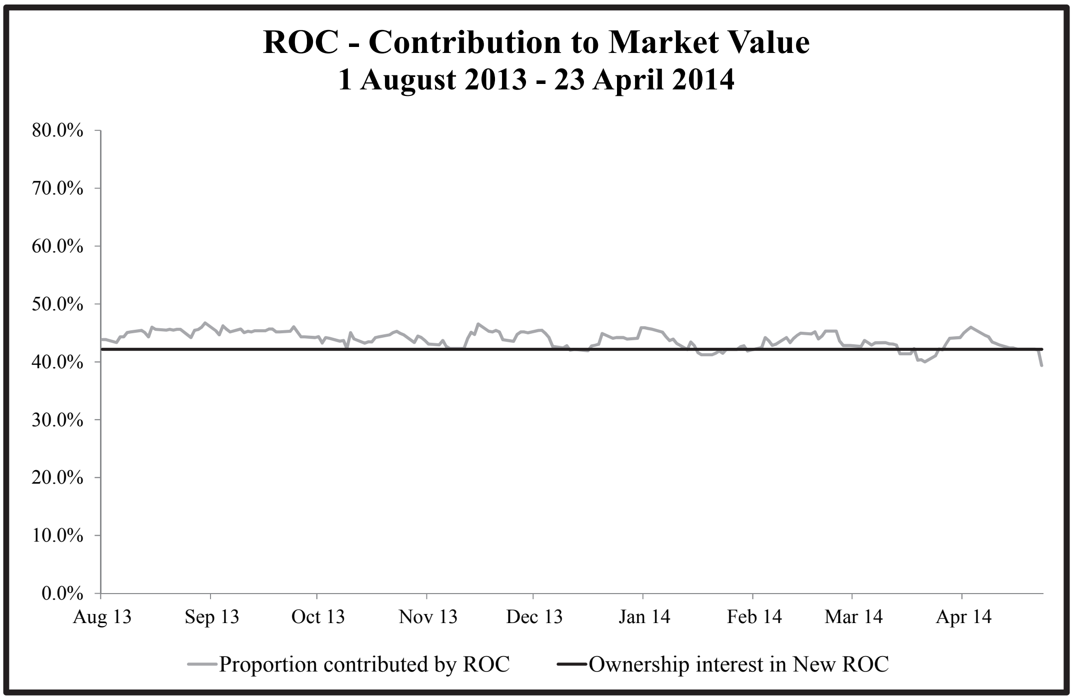
- **The Merger is a "merger of equals".**

  The Merger is a genuine "merger of equals" rather than a change of control transaction. The Merger terms have been agreed on a "nil premium" basis, with ROC and Horizon shareholders to hold interests in New ROC that are consistent with the relative sharemarket values of the two companies immediately before the announcement of the Merger. The chairman of New ROC will be Mike Harding (the current Chairman of ROC) and Brent Emmett (the current Chief Executive Officer of Horizon) will be the Managing Director and Chief Executive Officer. As a consequence, Grant Samuel has assessed the Merger by:

  - comparing the relative values contributed by ROC and Horizon shareholders with the interests that they will hold in New ROC. The value contributions have been assessed on the basis of:
    - sharemarket values; and
    - Grant Samuel's estimates of full underlying value;
  - comparing the relative contributions of ROC and Horizon on the basis of other parameters such as reserves, resources, production and earnings;
  - evaluating the benefits expected to be realised as a result of the Merger;
  - considering any disadvantages of the Merger; and
  - assessing whether, overall, ROC shareholders will be better off if the Merger proceeds than if it does not.

- **Based on sharemarket values prior to announcement of the Merger, the terms of the Merger are consistent with the value to be contributed by ROC shareholders to New ROC.**

  There is an active, well-informed market for shares in both ROC and Horizon. Accordingly, sharemarket values provide an objective measure of the value contributions to be made by ROC and Horizon shareholders to New ROC. ROC's contribution to the aggregate sharemarket value (based on daily closing prices) of the two companies since July 2013 is shown in the following chart:



Source: IRESS and Grant Samuel analysis

Notes: (1) The analysis is for the period following Horizon's issue of 162.2 million (approximately 14% of issued capital) at a price of A$0.33 to raise A$53.5 million.

(2) Market capitalisation calculated by reference to fully paid shares currently on issue only. On this basis, ROC shareholders will collectively hold a 42.2% interest in New ROC.

The following table shows volume weighted average prices ("VWAPs") for ROC and Horizon shares, the notional sharemarket capitalisations of the two companies and their contributions of sharemarket value to New ROC, for various periods before the announcement of the Merger:

Contribution of Sharemarket Value[3]

Period	ROC			Horizon		
	VWAP A$	Market Capitalisation (A$ million)	Contribution %	VWAP A$	Market Capitalisation (A$ million)	Contribution %
23 April 2014	0.459	315.6	40.9%	0.350	455.7	59.1%
1 week to 23 April 2014	0.462	317.7	41.4%	0.346	450.5	58.6%
1 month to 23 April 2014	0.463	318.4	43.0%	0.324	421.8	57.0%
3 months to 23 April 2014	0.462	317.7	43.0%	0.323	420.5	57.0%
6 months to 23 April 2014	0.459	315.6	43.3%	0.318	414.0	56.7%

The relative sharemarket values of the two companies have varied in a narrow band over the period prior to announcement. Nonetheless, overall it appears clear that the aggregate interests of ROC and Horizon shareholders in New ROC will be proportionate to sharemarket estimates of the values of the two companies. Accordingly, based on sharemarket values for the two companies, the Merger terms are fair.

3 Market capitalisation calculated by reference to fully paid shares currently on issue only.

- **Based on Grant Samuel's assessment of the underlying values of ROC and Horizon, ROC shareholders will contribute around 41% of the underlying value of New ROC.**

  The following table summarises the value contributed by ROC and Horizon to New ROC, based on Grant Samuel's estimated full underlying value of each company:

Relative Contribution – Full Underlying Value (US$ million)		
	Grant Samuel Estimates of Value[4]	
	ROC	Horizon
Value Contribution – High (US$ million)	**507**	**721**
Value Contribution – Low (US$ million)	**391**	**561**
Relative Value Contributions – High	41.3%	58.7%
Relative Value Contributions – Low	41.1%	58.9%

  Grant Samuel's assessment of the underlying value of ROC and Horizon suggests that, on a fully diluted basis, ROC is contributing approximately 41% of the underlying value of New ROC.

  Estimates of the underlying value of ROC and Horizon are sensitive to oil price assumptions and judgements about future project potential. Notwithstanding the uncertainties inherent in estimates of the underlying values of ROC and Horizon, it is reasonable to conclude that the collective interest of ROC shareholders in New ROC will be approximately proportionate to the underlying value to be contributed to New ROC. Accordingly, on the basis of Grant Samuel's estimates of the underlying values of ROC and Horizon, the Merger terms are fair.

- **Assessments of value need to be approached with considerable caution.**

  Grant Samuel's valuations of ROC and Horizon are summarised below:

ROC – Valuation Summary (US$ million)		
	Value Range	
	Low	High
Beibu Gulf Joint Venture	176	196
Zhao Dong Joint Venture	95	105
D35/D21/J4 PSC	12	27
Other producing assets	30	45
Exploration	16	62
BC Petroleum	65	70
Other assets and liabilities	-	-
Corporate costs (net of savings)	(60)	(55)
Enterprise value	**334**	**450**
Adjusted cash	66	66
LTI Rights and STI Rights	(9)	(9)
Value of equity	**391**	**507**

4 Underlying value has been estimated after adjusting for options and similar securities on issue. On this basis, ROC shareholders will hold a 41.6% interest in New ROC.

Horizon – Valuation Summary (US$ million)		
	Value Range	
	Low	High
PNG development assets (PDL 10 and PRL 21)	300	370
New Zealand assets	140	160
Beibu Gulf Joint Venture	243	270
Exploration	17	55
Other assets and liabilities	7	7
Corporate costs (net of savings)	(40)	(35)
Enterprise value	**667**	**827**
Adjusted net borrowings[5]	(101)	(101)
Options and share appreciation rights	(5)	(5)
Value of equity	**561**	**721**

The valuations of ROC and Horizon represent Grant Samuel's assessment of the full underlying value of each company. The valuations have been prepared in the context of, and for the purpose of analysing, the Merger. They have been prepared principally to allow a comparison of the value contribution by each company to New ROC. They do not represent Grant Samuel's view of the likely sharemarket value of the companies, individually or on a merged basis. Shares in listed companies typically trade at a discount to full underlying value.

The valuations are based on a number of important assumptions, including assumptions regarding oil prices. Oil price expectations and expectations regarding development prospects and future operating performance can change significantly over short periods of time. Such changes can have significant impacts on underlying value. Accordingly, while the values estimated are believed to be appropriate for the purpose of assessing the Merger, they may not be appropriate for other purposes or in the context of changed market conditions, changed economic circumstances or different operational prospects for the assets of ROC and Horizon.

Grant Samuel appointed RISC Operations Pty Limited ("RISC") as independent technical specialist to review the assets of ROC and Horizon. RISC's role included a review of reserves and resources, development plans, production profiles, operating costs, capital costs and exploration potential. RISC also prepared valuations of ROC's and Horizon's exploration interests. The report prepared by RISC is attached to and forms part of the full report from which this summary has been extracted.

Grant Samuel's valuations of the assets of ROC and Horizon represent overall judgements, having regard to a range of relevant evidence as to value. The valuations take into account the results of discounted cash flow ("DCF") analysis and, where appropriate, valuation evidence derived from transactions involving the relevant assets.

Grant Samuel undertook DCF analysis for those major operating assets and development projects of ROC and Horizon for which reliable cash flow projections could be developed. The DCF analysis was generally based on 2P (proved and probable) reserve production cases, although in some instances valuation cases that considered the production of 2C contingent resources were also considered.

The DCF models projected cash flows from 1 January 2014. Cash flows for the oil and gas assets of ROC and Horizon were projected in nominal US$ terms and discounted to present values using nominal discount rates of 9.5-10.5%. These discount rates were selected having regard to estimates of costs of capital for oil and gas assets based on analysis using the capital asset price model. For the purposes of the DCF analysis, Grant Samuel assumed that Brent oil prices would decline from prevailing spot prices to long run prices (in real terms) in the range US$85-95/bbl.

5 Takes into account the $78 million receivable from Osaka Gas following the grant of PDL 10.

- **Judgements regarding the value of Horizon's PNG assets are critical to the analysis.**

  The majority of the assets of ROC and Horizon can be valued with some confidence. Most of the assets are mature and well understood (e.g. Beibu Gulf, Zhao Dong, Maari/Manaia, Cliff Head and the United Kingdom assets). In other cases, recent acquisitions or contractual terms provide evidence as to value (e.g. ROC's Malaysian assets). On the other hand, there is considerably less certainty regarding the value of Horizon's PNG assets. The valuation of these assets is critical to an assessment of the Merger terms. Grant Samuel has valued Horizon's PNG development assets in the range $300-370 million.

  Horizon's PNG assets are situated in the Foreland Basin in the Western Province of PNG. They are at an early stage of development. The petroleum development licence for Horizon's first PNG development (a condensate stripping project for the Stanley Field) was granted on 30 May 2014. The much larger Elevala/Ketu/Tingu ("EKT") condensate stripping project is less advanced.

  The material value upside for Horizon's PNG assets is associated with commercialisation of the gas resources at Stanley and EKT fields. Stanley gas could potentially be sold to local mining operations or other local customers. The much larger gas volumes at EKT will require access to an LNG project if they are to be commercialised in the foreseeable future. Horizon has examined various LNG development concepts, generally involving the aggregation of EKT gas with other Foreland Basin gas to provide the feedstock for a medium sized LNG facility at the coast. There are a variety of other gas resources in the Foreland Basin that would potentially be suitable for this purpose. While the timing of any development is uncertain, there are multiple options for the development of Horizon's gas.

  Horizon's joint venture partners in the Stanley and EKT fields should be incentivised to commercialise the gas. Osaka Gas and Mitsubishi Corporation are both focussed on gas off take and Talisman has interests in significant gas fields to the south which could be commercialised in conjunction with EKT. The successful commencement of production by the PNG LNG project should provide assurance to investors, industry participants and potential gas off takers that PNG is an attractive environment for LNG development. Accordingly, while Horizon's plans for an LNG development are currently essentially conceptual, in Grant Samuel's view, there is good reason to be confident that Horizon's gas will ultimately be monetised.

  Successful development of the PNG assets, and in particular successful medium term commercialisation of the gas resources on the basis currently contemplated through their utilisation as feedstock for an LNG project, could deliver value materially greater than Grant Samuel's estimate of current values. Such an outcome (with the benefit of hindsight) would mean that the Merger had been extremely advantageous for ROC shareholders. Conversely, an outcome in which large scale gas commercialisation is not achieved or is significantly delayed is also conceivable and would mean that, in retrospect, the Merger was not in the best interests of ROC shareholders.

  In this context, a broad range of valuation conclusions could reasonably be reached. Shareholders who take a materially more conservative view than Grant Samuel on the value of Horizon's PNG assets could conclude that the terms of the Merger are not fair to ROC shareholders. Conversely, shareholders with a strongly positive view on Horizon's PNG assets could conclude that the Merger is value accretive for ROC shareholders.

- **The Merger terms are fair to ROC shareholders.**

  The proportional interests in New ROC to be held by ROC and Horizon shareholders appear consistent with the relative contributions of value to be made to New ROC:

  - sharemarket values for the period since July 2013 prior to the Merger suggest that ROC will contribute around 41-43% of the total value contributed to New ROC; and
  - based on Grant Samuel's assessment of the full underlying values of ROC and Horizon, ROC shareholders will contribute approximately 41% of the underlying value of New ROC.

  Overall, ROC shareholders' aggregate interest in New ROC (around 42%) will be approximately proportionate to ROC's contribution of value to New ROC. Accordingly, in Grant Samuel's opinion, the Merger terms are fair to ROC shareholders.

- **New ROC will have a different risk, growth and earnings profile after the Merger.**

  New ROC will have a different growth, risk and earnings profile than a standalone ROC. New ROC will be a more growth focussed business, with a series of growth opportunities in PNG. However, the corollary of these growth opportunities are risks to which ROC is not currently exposed, including development risks and PNG sovereign risk.

  Whereas ROC held net cash at 31 December 2013 of $65 million, New ROC will have a modest level of debt (pro forma net debt as at 31 December 2013 of around $50 million). The shift in the company's capital structure theoretically increases the level of financial risk associated with New ROC but this level of gearing (around 10%) is not significant having regard to the market value, asset base and operating cash flows of New ROC. While New ROC's share of the funding required for the PNG developments will be substantial, it should be manageable given the free cash flows expected to be generated by the producing assets of New ROC (assuming oil prices around current levels).

  Pro forma forecasts of earnings or free cash flows have not been prepared for New ROC. However, it is likely that, in the short term, free cash flow per share for New ROC would be lower than for ROC on a standalone basis given the need to fund the developments in PNG and because earnings from the PNG assets will not commence for a number of years. In the medium term, however, the Merger should result in strong growth in earnings and free cash flows (assuming the successful development of the PNG assets).

  In the short term, these changes in the characteristics of New ROC should have a broadly neutral or possibly marginally positive impact on value, with longer term growth in earnings and free cash flows essentially offsetting shorter term development costs and risks. The sharemarket's response to the announcement of the Merger, with shares in both ROC and Horizon trading higher, suggest that market participants have a similar view. However, shareholders with a particular focus on short term cash flows, little appetite for development risks or a limited interest in long term exposure to oil and gas assets, could take a different view, which might lead them to a conclusion that the Merger is not in their best interests.

- **The benefits of the Merger should in aggregate be significant.**

  The Merger will produce a number of benefits. New ROC will be a substantially larger company than ROC on a standalone basis, with a pro forma market capitalisation approaching A$900 million (based on share prices as at 13 June 2014). It will have a strong balance sheet with pro forma net debt of around $50 million as at 31 December 2013 and strong cash flows from producing assets in China, New Zealand, Malaysia, Australia and the United Kingdom. New ROC should have greater access to both equity and debt than ROC on a standalone basis and greater capacity to entertain larger and more risky growth opportunities. New ROC will have greater diversity in terms of geographic exposure than ROC on a standalone basis (although some shareholders may prefer to achieve this diversification directly through their own investment decisions).

  New ROC's significantly larger market capitalisation, greater share liquidity and improved growth prospects should enhance its appeal to institutional investors. While merger synergies are not expected to be material, it is likely that some corporate cost reductions will be achieved. These cost reductions could be of the order of $4-5 million per annum.

  The most compelling benefit of the Merger is the direct access to growth opportunities provided by Horizon's PNG assets. The majority of ROC's assets are mature or in decline (e.g. Beibu Gulf, Zhao Dong, Cliff Head and the United Kingdom assets). The value of ROC's 48% interest in BC Petroleum (which is party to the Balai Cluster risk sharing contract) represents no more than the reimbursement of capital expenditure already incurred. As a consequence, there are only limited growth options in ROC's asset portfolio (although it has recently farmed into a production sharing contract offshore Malaysia that offers upside potential). Horizon's PNG assets will provide an opportunity to participate in the Stanley liquid stripping project, for which the production development licence has been granted, a much larger and earlier stage liquids stripping project at EKT and a large scale gas commercialisation project. Successful commercialisation of the gas resources at EKT through their use as feedstock for an LNG project is likely to deliver material additional value to shareholders in New ROC.

In Grant Samuel's view, none of the likely benefits of the Merger is by itself compelling and many will only be realised over time. To some extent, the benefits of the Merger essentially constitute growth options not available to ROC on a standalone basis. The extent and timing of New ROC's realisation of value from these options is uncertain and will depend on future circumstances and management decisions.

Nonetheless, in Grant Samuel's opinion, the benefits of the Merger are in aggregate significant.

- **ROC's strong share price has risen significantly since the announcement of the Merger. This appears to reflect a market view that the Merger will result in a material re-rating of New ROC and represents a strong endorsement of the Merger.**

  The increased market capitalisation, greater share liquidity, cost synergies and enhanced growth prospects for New ROC all suggest that there is good reason to expect a market re-rating of New ROC.

  Since the announcement of the Merger, ROC's share price has increased by around 21% (based on ROC's closing share prices on 23 April 2014 and 13 June 2014) while in the same period the wider market has been relatively flat. Relative to an undisturbed share price on 22 April 2014 of A$0.335[6], Horizon's share price has increased by around 13%. On this basis, the growth in the combined market capitalisation of the two companies is in the order of 18% over the period. There are a number of factors that may have contributed to the strong share price performance of ROC and Horizon. However, it appears reasonable to conclude that this outperformance, at least in part, reflects market anticipation of the re-rating benefits of the Merger. ROC (and Horizon) shareholders would stand to lose the recent price appreciation if the Merger did not proceed.

- **ROC shareholders will not give up the opportunity to realise a premium for control.**

  ROC shareholders will not give up the opportunity to realise a full premium for control at some later stage. There will still be an opportunity to realise a full premium through a subsequent change of control transaction involving New ROC. New ROC's share register will arguably be more open than ROC's existing share register, with the largest shareholder holding around 14% of the shares in New ROC. On one view, the prospects of New ROC receiving a change of control proposal should be greater than for ROC on a standalone basis, given the expected ultimate scale and potential corporate appeal of the PNG assets.

- **The other disadvantages of the Merger for ROC shareholders are not significant.**

  The other disadvantages of the Merger for ROC shareholders include:

  - New ROC will have a lower proportion of liquids in the overall hydrocarbon mix (although this is reflected in Grant Samuel's estimates of underlying value and should be reflected in sharemarket values of ROC and Horizon);
  - ROC shareholders' proportionate exposure to 2P reserves will decline. On other hand, ROC shareholders will enjoy a substantial increase in their exposure to 2C resources;
  - ROC shareholders will have a more highly geared exposure (both positive and negative) to movements in the oil price, as New ROC will have net debt compared to ROC's net cash;
  - a significant part of Horizon's value is contributed by assets in PNG. The sovereign risk associated with these assets should be reflected in Horizon's market value and has been taken into account in Grant Samuel's valuation of Horizon. Nevertheless, following the Merger ROC shareholders will be exposed to a greater degree of sovereign risk than is currently the case;

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[6] Horizon's share price increased by around 10% on 23 April 2014.

- ROC shareholders will be exposed to exploration and development risk to a greater degree than in ROC on a standalone basis. In Grant Samuel's view, the additional risk will be offset by the growth potential contributed by the Horizon assets. In any event, the additional risk has been taken into account in Grant Samuel's valuation analysis and should be reflected in the sharemarket value of Horizon; and
- transaction costs related to the Merger are estimated to total around $8.3 million, of which ROC shareholders will effectively fund 42% ($3.5 million). Of these, approximately $2 million will be incurred by ROC on a standalone basis if the Merger does not proceed. The incremental costs to be funded by ROC shareholders if the Merger is implemented ($1.5 million) are not material having regard to the values of ROC and Horizon.

There are implementation risks in any merger but in this case the complementary nature of the ROC and Horizon businesses should reduce such risk.

- **The Merger is in the best interests of ROC shareholders.**

  On the basis of merger analysis, the aggregate interest of ROC shareholders in New ROC will be approximately proportionate to ROC's contribution of value. The Merger benefits are collectively significant and outweigh the disadvantages. ROC shareholders will be better off if the Merger proceeds than if it does not. Accordingly, in Grant Samuel's opinion, the Merger is in the best interests of ROC shareholders.

4 Other Matters

The report has been prepared for the directors of ROC. However, as ROC intends to release this report publicly it may be construed as advice to shareholders. To this extent, this report is general financial product advice only and has been prepared without taking into account the objectives, financial situation or needs of individual ROC shareholders. It is a matter for individual shareholders as to whether to buy, hold or sell shares in ROC, Horizon or New ROC. These are investment decisions upon which Grant Samuel does not offer an opinion. Shareholders should consult their own professional adviser in this regard.
Grant Samuel has prepared a Financial Services Guide as required by the Corporations Act, 2001. The Financial Services Guide is included at the beginning of the full report.

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

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

Yours faithfully
GRANT SAMUEL & ASSOCIATES PTY LIMITED

Grant Samuel & Associates

Financial Services Guide
and
Independent Expert's Report
in relation to the Proposed Merger with
Horizon Oil Limited

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

15 June 2014

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Financial Services Guide

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

The Corporations Act, 2001 requires Grant Samuel to provide this Financial Services Guide ("FSG") in connection with its provision to the board of directors ("Board") of Roc Oil Company Limited ("ROC") of an independent expert's report in relation to a proposal by ROC to merge with Horizon Oil Limited ("Horizon") ("the ROC Report"). Grant Samuel understands that the Board intends to lodge the ROC Report with the Australian Securities Exchange for public release.

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

When providing independent expert reports, Grant Samuel's client is the Entity to which it provides the report. Grant Samuel receives its remuneration from the Entity. In respect of the ROC Report, Grant Samuel will receive a fixed fee of $275,000 plus reimbursement of out-of-pocket expenses (as stated in Section 9.3 of the ROC Report).

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

Grant Samuel is required to be independent of the Entity in order to provide an independent expert's report. The guidelines for independence in the preparation of reports are set out in Regulatory Guide 112 issued by the Australian Securities & Investments Commission on 30 March 2011. The following information in relation to the independence of Grant Samuel is stated in Section 9.3 of the ROC Report:

> *"Grant Samuel and its related entities do not have at the date of this report, and have not had within the previous two years, any business or professional relationship with ROC or Horizon or any financial or other interest that could reasonably be regarded as capable of affecting its ability to provide an unbiased opinion in relation to the Merger.*
>
> *Grant Samuel had no part in the formulation of the Merger. Its only role has been the preparation of this report.*
>
> *Grant Samuel will receive a fixed fee of $275,000 for the preparation of this report. This fee is not contingent on the conclusions reached or the outcome of the Merger. Grant Samuel's out of pocket expenses in relation to the preparation of the report will be reimbursed. Grant Samuel will receive no other benefit for the preparation of this report.*
>
> *Grant Samuel considers itself to be independent in terms of Regulatory Guide 112 issued by the ASIC on 30 March 2011."*

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Table of Contents

1 **Introduction** ... 1

2 **Scope of the Report** ... 2
- 2.1 **Purpose of the Report** ... 2
- 2.2 **Basis of Evaluation** ... 2
- 2.3 **Sources of the Information** ... 3
- 2.4 **Limitations and Reliance on Information** ... 3

3 **Global Oil and Gas Sector** ... 6
- 3.1 **Overview** ... 6
- 3.2 **Global Oil Sector** ... 6
- 3.3 **Global Gas Sector** ... 8

4 **Profile of Roc Oil Company Limited** ... 11
- 4.1 **Overview** ... 11
- 4.2 **Financial Performance** ... 12
- 4.3 **Financial Position** ... 14
- 4.4 **Capital Structure and Ownership** ... 15
- 4.5 **Share Price Performance** ... 16
- 4.6 **Operations** ... 18

5 **Profile of Horizon Oil Limited** ... 26
- 5.1 **Overview** ... 26
- 5.2 **Financial Performance** ... 27
- 5.3 **Financial Position** ... 29
- 5.4 **Capital Structure and Ownership** ... 31
- 5.5 **Share Price Performance** ... 33
- 5.6 **Operations** ... 35

6 **Profile of New ROC** ... 42
- 6.1 **Operations** ... 42
- 6.2 **Directors and Management** ... 42
- 6.3 **Earnings and Dividends** ... 43
- 6.4 **Financial Position** ... 43
- 6.5 **Capital Structure and Ownership** ... 44

7 **Valuation Analysis** ... 45
- 7.1 **Valuation Methodology** ... 45
- 7.2 **Key Assumptions** ... 46
- 7.3 **Valuation of ROC** ... 48
- 7.4 **Valuation of Horizon** ... 58

8 **Evaluation of the Merger** ... 72
- 8.1 **Conclusion** ... 72
- 8.2 **Approach to Evaluation** ... 73
- 8.3 **Relative Contributions – Sharemarket Values** ... 73
- 8.4 **Relative Contributions – Full Underlying Value** ... 75
- 8.5 **Relative Contributions – Other Parameters** ... 76
- 8.6 **Investment Characteristics** ... 77
- 8.7 **Benefits of the Merger** ... 78
- 8.8 **Share Trading Post the Merger Announcement** ... 79
- 8.9 **Control Issues** ... 79
- 8.10 **Other Disadvantages** ... 80
- 8.11 **Other Matters** ... 80

9 Qualifications, Declarations and Consents 81
9.1 Qualifications 81
9.2 Disclaimers 81
9.3 Independence 81
9.4 Declarations 81
9.5 Consents 82
9.6 Other 82

Appendices

1 Glossary of Terms
2 Independent Technical Specialist Report - RISC Operations Pty Limited
3 Selection of Discount Rate
4 Market Evidence

Dollar amounts in this report relate to United States dollars unless otherwise specified

1 Introduction

On 29 April 2014, Roc Oil Company Limited ("ROC") announced that it had entered into a merger implementation deed with Horizon Oil Limited ("Horizon") ("the Merger"). Horizon is a petroleum exploration, development and production company listed on the Australian Securities Exchange ("ASX") with assets located in the People's Republic of China ("China"), Papua New Guinea ("PNG") and New Zealand.

The Merger is to be implemented by way of a scheme of arrangement under Section 411 of the Corporations Act, 2001 ("Corporations Act") between Horizon and its shareholders. Under the terms of the Merger Horizon shareholders will receive 0.724 ROC shares for every Horizon share. As a result, existing ROC shareholders will hold approximately 42% of the shares in the merged company ("New ROC") and existing Horizon shareholders will hold the remaining 58%. The Merger is subject to the satisfaction of a number of conditions including Horizon shareholder approval and completion of the Osaka Gas Asset Sale Agreement[1]. Other features of the Merger include:

- ROC and Horizon have agreed to certain exclusivity restrictions including no-shop and no-talk restrictions and a notification obligation with the no-talk and notification provisions subject to a carve out in respect of the fiduciary and statutory obligations of ROC and Horizon directors;
- the board of New ROC will comprise three current non-executive directors from ROC and four current non-executive directors and one current executive director from Horizon. The current Chairman of ROC will be the Chairman of New ROC. The current chief executive officer ("CEO") of Horizon will be the CEO of New ROC and the current CEO of ROC will continue in an executive role until April 2015. The senior management team will be drawn from the existing management teams of ROC and Horizon;
- the "Roc Oil" brand will be used in the conduct of New ROC's business in China and South East Asia while the "Horizon Oil" brand will be used in PNG and New Zealand;
- Horizon partly paid ordinary shareholders will receive 0.724 shares for each partly paid share held and remain liable to New ROC for the residual payments in accordance with their current terms;
- Horizon options and share appreciation rights will either be transferred to ROC or cancelled prior to implementation of the scheme of arrangement in return for a combination of cash, options to acquire New ROC shares (in the case of Horizon options) or performance entitlements over ROC shares (in the case of Horizon share appreciation rights) as agreed by Horizon, ROC and the relevant option or rights holder;
- ROC shares issued to Horizon shareholders will rank equally with all other ROC shares on issue. Fractional entitlements to ROC shares will be rounded to the nearest whole number; and
- Horizon shareholders who are (or are acting on behalf of) residents of a jurisdiction outside of Australia (or its external territories) or with registered addresses outside of Australia (or its external territories) will be "Foreign Horizon Shareholders" (unless determined otherwise by Horizon and ROC) and will not receive ROC shares. Such shareholders will receive in cash the net proceeds of the sale on the ASX of the ROC shares to which they would otherwise have been entitled.

Implementation of the Horizon scheme of arrangement will trigger a redemption right for the holders of Horizon convertible bonds.

On 15 May 2014, ROC received a notice under Section 249D of the Corporations Act from shareholders holding more than 5% of its issued capital requesting ROC hold an extraordinary general meeting of shareholders to consider a resolution to amend its constitution. The amendment relates to the insertion of a new rule restricting ROC from issuing shares or securities convertible into shares without the prior approval of shareholders where the new issue represents more than 30% of the shares on issue at date of announcement. On 5 June 2014, ROC issued a notice for an extraordinary general meeting to be held on 11 July 2014.

In this report, dollar amounts relate to United States dollars unless otherwise specified.

[1] The Asset Sale Agreement dated 23 May 2013 entered into by Horizon and Osaka Gas Co. Ltd of Japan (see Section 5.1).

2 Scope of the Report

2.1 Purpose of the Report

Although there is no requirement in the present circumstances for an independent expert's report pursuant to the Corporations Act or the ASX Listing Rules, the directors of ROC have engaged Grant Samuel & Associates Pty Limited ("Grant Samuel") to prepare an independent expert's report setting out whether, in its opinion, the Merger is in the best interests of ROC shareholders and to state reasons for that opinion.

This report has been prepared for the directors of ROC. However, as ROC intends to release this report publicly it may be construed as advice to shareholders. To this extent, this report is general financial product advice only and has been prepared without taking into account the objectives, financial situation or needs of individual ROC shareholders. It is a matter for individual shareholders as to whether to buy, hold or sell shares in ROC, Horizon or New ROC. These are investment decisions upon which Grant Samuel does not offer an opinion. Shareholders should consult their own professional adviser in this regard.

2.2 Basis of Evaluation

There is no legal definition of the expression "in the best interests". However, the Australian Securities & Investments Commission ("ASIC") has issued Regulatory Guide 111 which establishes guidelines in respect of independent expert's reports. ASIC Regulatory Guide 111 differentiates between the analysis required for control transactions and other transactions. In the context of control transactions (whether by takeover bid, by scheme of arrangement, by the issue of securities or by selective capital reduction or buyback), the expert is required to distinguish between "fair" and "reasonable". A proposal that was "fair and reasonable" or "not fair but reasonable" would be in the best interests of shareholders.

For most other transactions the expert is to weigh up the advantages and disadvantages of the proposal for shareholders. This involves a judgement on the part of the expert as to the overall commercial effect of the proposal, the circumstances that have led to the proposal and the alternatives available. The expert must weigh up the advantages and disadvantages of the proposal and form an overall view as to whether the shareholders are likely to be better off if the proposal is implemented than if it is not. If the advantages outweigh the disadvantages, a proposal would be in the best interests of shareholders.

The Merger is not a control transaction. Following completion of the Merger, ROC shareholders will, in aggregate, own approximately 42% of New ROC and Horizon shareholders will own approximately 58%. Although the share register will change significantly, no shareholder will acquire an interest in 20% or more of the issued shares in ROC as a consequence of the Merger. Accordingly, Grant Samuel has evaluated the Merger by assessing the overall impact on the shareholders of ROC and formed a judgement as to whether the expected benefits outweigh any disadvantages and risks that might result.

In forming its opinion as to whether the Merger is in the best interests of ROC shareholders, Grant Samuel has considered the following:

- the terms of the Merger and their impact on shareholders (including in term of value contribution);
- the impact on ownership and control of ROC;
- the investment characteristics of New ROC relative to those of ROC on a standalone basis;
- the potential for a re-rating of ROC shares and their likely market price relative to the market price of shares in a standalone ROC;
- the prospects for ROC shareholders to realise full underlying value through a subsequent control transaction for New ROC;
- any other advantages and benefits arising from the Merger; and
- the costs, disadvantages and risks of the Merger.

2.3 Sources of the Information

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

Publicly Available Information

- the Merger Implementation Deed dated 29 April 2014;
- annual reports of ROC for the five years ended 31 December 2013;
- annual reports of Horizon for the five years ended 30 June 2013 and the half year announcement of Horizon for the six months ended 31 December 2013;
- quarterly activity reports for ROC and Horizon;
- press releases, public announcements, media and analyst presentation material and other public filings by ROC and Horizon including information available on their websites;
- brokers' reports and recent press articles on ROC and Horizon and the oil and gas industry; and
- sharemarket data and related information on Australian and international listed companies engaged in the oil and gas industry and on acquisitions of companies and businesses in this industry.

Non Public Information provided by ROC

- budget for the year ending 31 December 2014 prepared by ROC management;
- detailed cash flows models including projections for ROC's oil and gas assets; and
- other confidential documents, board papers, presentations and working papers.

Non Public Information provided by Horizon

- the draft Horizon Scheme Booklet;
- management accounts for Horizon for the period ended 30 April 2014 (including forecast for the year ending 30 June 2014);
- budget for the year ending 31 December 2014 prepared by Horizon management;
- detailed cash flow models including projections for Horizon's oil and gas assets; and
- other confidential documents, board papers, presentations and working papers.

In preparing this report, Grant Samuel held discussions with, and obtained information from, senior management of ROC and Horizon and their respective advisers.

2.4 Limitations and Reliance on Information

Grant Samuel believes that its opinion must be considered as a whole and that selecting portions of the analysis or factors considered by it, without considering all factors and analyses together, could create a misleading view of the process employed and the conclusions reached. Any attempt to do so could lead to undue emphasis on a particular factor or analysis. The preparation of an opinion is a complex process and is not necessarily susceptible to partial analysis or summary.

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

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

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

- ROC has advised Grant Samuel that it has undertaken due diligence on Horizon; and
- Grant Samuel is not in a position nor is it practicable to undertake its own "due diligence" investigation of the type undertaken by accountants, lawyers or other advisers.

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

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

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

Grant Samuel appointed RISC Operations Pty Limited ("RISC") as independent technical specialist to review the assets of ROC and Horizon for Grant Samuel. RISC's role included a review of reserves and resources, development plans, production schedules, operating costs, capital costs and exploration activities. RISC also prepared valuations of ROC's and Horizon's exploration interests. The report prepared by RISC forms part of this report and is attached at Appendix 2.

The information provided to Grant Samuel and RISC included life of field production and development plans, forecasts and feasibility studies for the key assets of ROC and Horizon. ROC and Horizon are responsible for the information contained in the life of field production and development plans, forecasts and feasibility studies ("the forward looking information").

The achievability of the forward looking information is not warranted or guaranteed by Grant Samuel or RISC. Future profits and cash flows are inherently uncertain. They are predictions by management of future events that cannot be assured and are not necessarily based on assumptions, many of which are beyond the control of the company or its management. Actual results may be significantly more or less favourable.

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

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

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

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

- matters such as title, compliance with laws and regulations and contracts in place are in good standing and will remain so and that there are no material legal proceedings, other than as publicly disclosed;
- the assessments by ROC and its advisers with regard to legal, regulatory, tax and accounting matters relating to the transaction are accurate and complete;
- the publicly available information relied on by Grant Samuel in its analysis was accurate and not misleading;
- the Merger will be implemented in accordance with its terms; and
- the legal mechanisms to implement the Merger are correct and will be effective.

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

3 Global Oil and Gas Sector

3.1 Overview

World energy consumption has increased by an average of 2.0% per annum since 1990 and is expected to grow on average by 1.5% per annum to 2035[2]. Most of the world's energy requirements are met from five major sources (oil, coal, natural gas, nuclear and hydroelectricity) although renewable sources of energy are increasing in importance. Recent years have seen high and volatile world energy prices signifying shifting supply and demand conditions, changing geopolitical circumstances, increased interest in the threat of climate change and unsettled economic conditions. This has increased demand for natural gas worldwide and encouraged the growth of renewable energy sources.

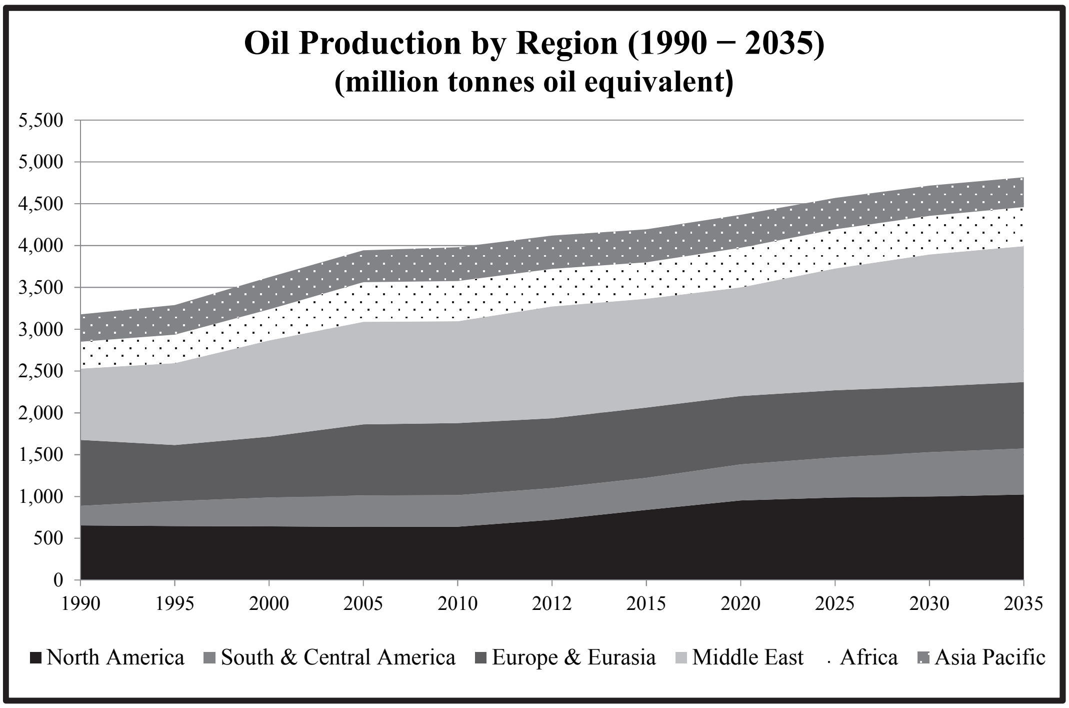
Since 1990 consumption of both coal and natural gas has grown on average by 2.4% per annum while growth in oil consumption has been slower at 1.2% per annum. As a consequence, oil's share of global energy consumption has declined from around 39% in 1990 to 33% in 2012 and is expected to decline to around 28% in 2035. Nevertheless, it remains an important source of energy and oil consumption is forecast to grow at around 0.8% per annum to 2035. At the same time consumption of natural gas is expected to grow at 1.9% per annum with its share of consumption expected to increase from 24% in 2012 to around 26% in 2035.

3.2 Global Oil Sector

Supply and Demand

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

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



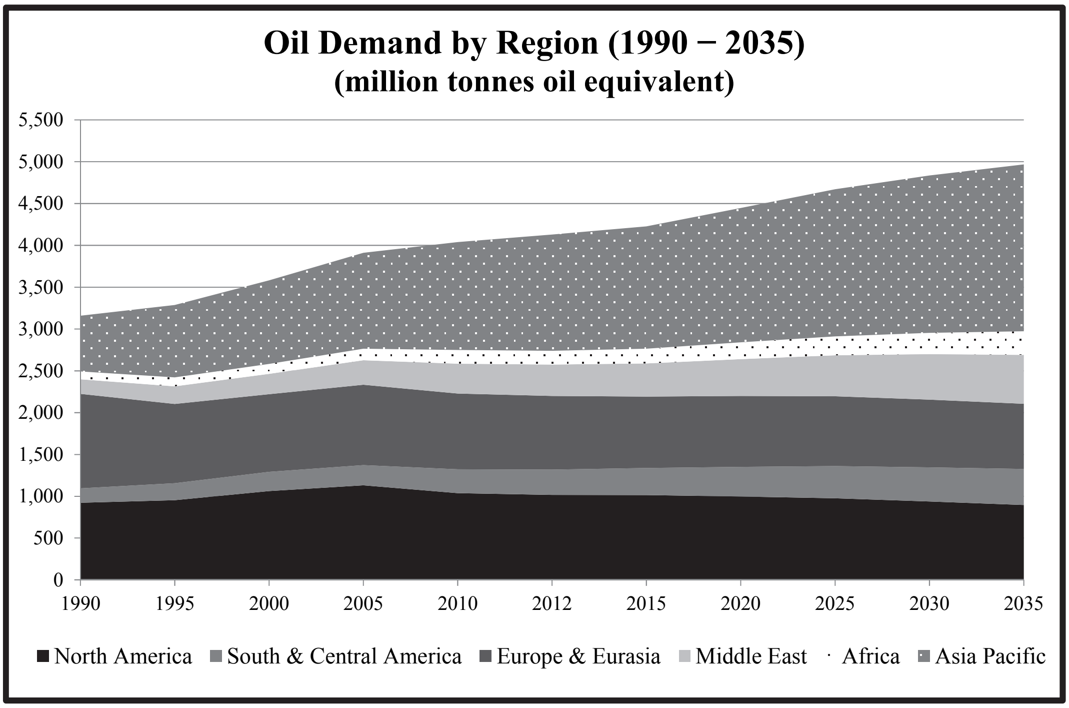
Source: *"BP Energy Outlook 2035"*, BP plc, January 2014

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

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

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

In 2005, the Asia Pacific region became the largest consumer of oil, followed by North America. By 2035, oil consumption in the Asia Pacific region is expected to be more than double the consumption in North America, reflecting increased demand in China and India, particularly for use in transport. Over the same period, oil consumption in North America and Europe & Eurasia is expected to decline.



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

Pricing

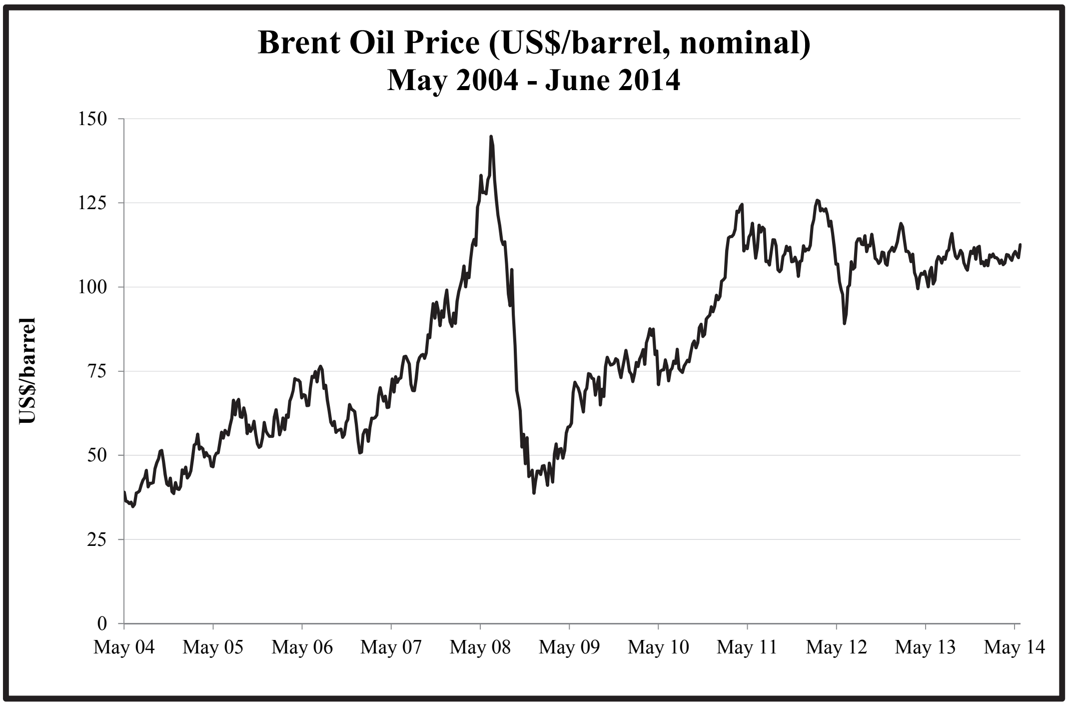
Oil is one of the most heavily traded commodities in the world. Prices are typically set against one of the following two international benchmarks and are adjusted to reflect the specific characteristics of the products and the location of the ports of origin and destination:

- West Texas Intermediate ("WTI"), a light, sweet crude oil, is the primary benchmark for oil produced in the United States. Cushing, Oklahoma, is a major hub and delivery location for WTI and represents the settlement point for WTI. Futures contracts on WTI are traded on NYMEX[4]; and
- Dated Brent ("Brent"), which is also a light crude oil, although not as light as WTI, is a composite blend of oils from 15 different oilfields in the North Sea. It has historically been used as a European crude oil benchmark but due to United States market specific impacts on the WTI, Brent is now more widely used as a global benchmark price for oil.

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

The WTI and Brent benchmarks have historically traded in line with each other, but an increase in United States production combined with a shortage of pipeline capacity to transport the oil to refiners has led to a build up of WTI inventories and to WTI trading at a discount to Brent over the past three years.

The Brent oil price over the past ten years is illustrated below:



Source: IRESS

Overall, the oil price has increased significantly over the past decade. It trended up in the five years to July 2008 despite the global financial crisis of late 2007 and the first half of 2008. However, weaker economic conditions eventually affected oil markets and the Brent oil price fell from a high of $145/bbl in early July 2008 to $31/bbl in late December 2008. Since then, the oil price has slowly recovered and has broadly traded in the $100-125/bbl range in the last three years. Key to this recovery has been OPEC's decision to restrain production, as well as increasing demand from developing countries in Asia. Political instability across North Africa and the Middle East has caused some price volatility but has also provided general support for a higher oil price.

3.3 Global Gas Sector

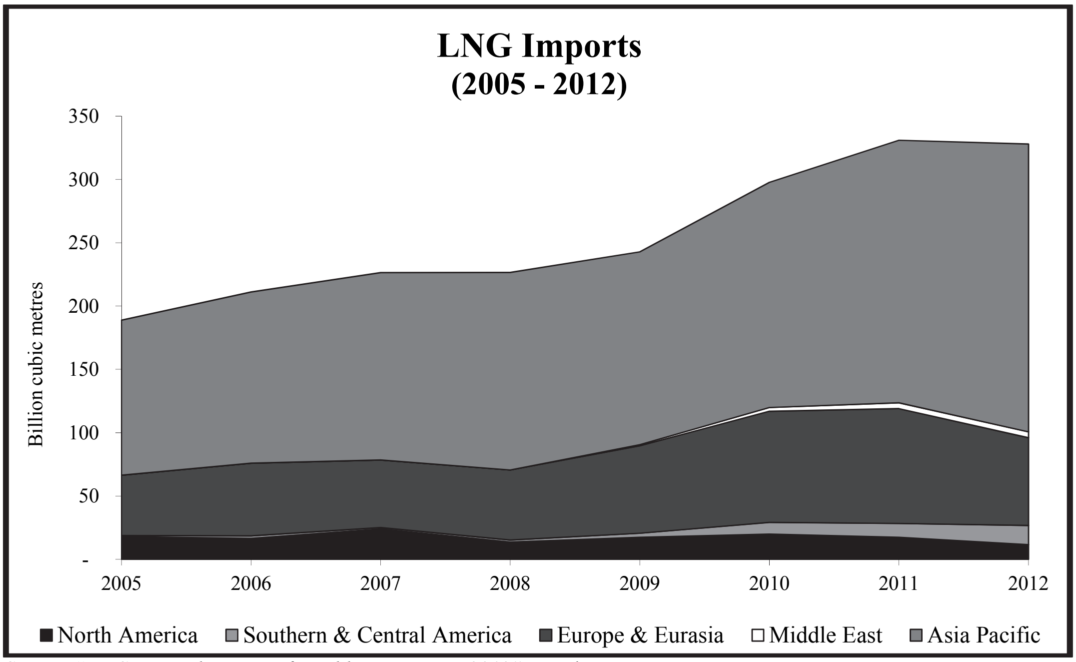
Supply and Demand

Natural gas is a fuel source produced during the breakdown of organic matter. It primarily comprises methane but may also contain hydrocarbons (such as propane, butane and ethane), nitrogen and carbon dioxide. It has a range of uses in the industrial, commercial and domestic sectors.

There are two main types of natural gas produced: conventional gas which is typically found in underground reservoirs trapped in rock sometimes in association with oil (both onshore and offshore) and unconventional gas such as coal seam gas, (contained within coal seams), shale gas (contained within low permeability organic rich rocks), tight gas (contained in low permeability reservoir rocks) and gas from renewable sources such as biogas (landfill and sewage gas) and biomass (wood, wood waste and sugarcane residue).

Around 31% of global natural gas production is traded internationally, with 21% of production delivered via pipelines and 10% delivered as liquefied natural gas[5] ("LNG") mostly under long term contracts (although the importance of spot sales is growing).

Due to a lack of natural gas resources and access to an international gas transmission pipeline network, Asia is the major importing region for LNG, primarily for power generation. Japan, which is heavily reliant on LNG (this reliance has been exacerbated by the recent Fukushima nuclear disaster), was the world's largest importer of LNG in 2012 (119bcm) ahead of South Korea (50bcm). Continued strong demand from both these countries is expected to be supplemented by growth in demand from China[6] and other Asian countries and, to a lesser extent, Europe:



Source: "*BP Statistical Review of World Energy June 2013*", BP plc.

Qatar was the largest exporter of LNG in 2012, followed by Malaysia, Australia, Nigeria and Indonesia. Global installed LNG production capacity of 281mtpa at the end of 2012 is expected to increase 110mtpa to approximately 290mtpa by 2017. Over half of the additional capacity relates to projects in Australia.

Technical advances and regulatory changes have facilitated the commercialisation of the very large shale gas resources in the United States and weak domestic gas prices have led to the development of a large number of LNG proposals. However, export to countries that are not party to free trade agreements ("FTAs") with the United States (all the major LNG importers bar South Korea[7]) is subject to the issue of a non-FTA export licence. Uncertainties relating to the non-FTA approval process (timing and risk of approval being revoked) combined with the risk that increased LNG exports might result in higher domestic gas prices mean that LNG exports from the United States are unlikely to be a major factor for the global LNG sector until the next decade. Canada also has a number of prospective LNG projects but they are all still at pre-final investment decision stage and would generally not enter production until the next decade.

5 LNG production involves the cooling of natural gas into liquid form. This reduces the volume of gas by a factor of approximately 600 times making it more economic to transport. LNG is transported in specially designed tankers for delivery to purpose built inbound terminals, where it is converted back into gas before being used for fuel.

6 China has implemented a five year plan to gasify its economy by increasing the share of gas in the energy mix from around 4% to 8% by 2015 and around 10% by 2020. This increased demand for gas is expected to be satisfied by an increase in domestic shale gas production and gas imports, both in the form of LNG and gas transported via pipelines from Russia and the Middle East.

7 Countries that are parties to FTAs with the United States and import LNG are Canada, Mexico, Dominican Republic, Chile Singapore and South Korea.

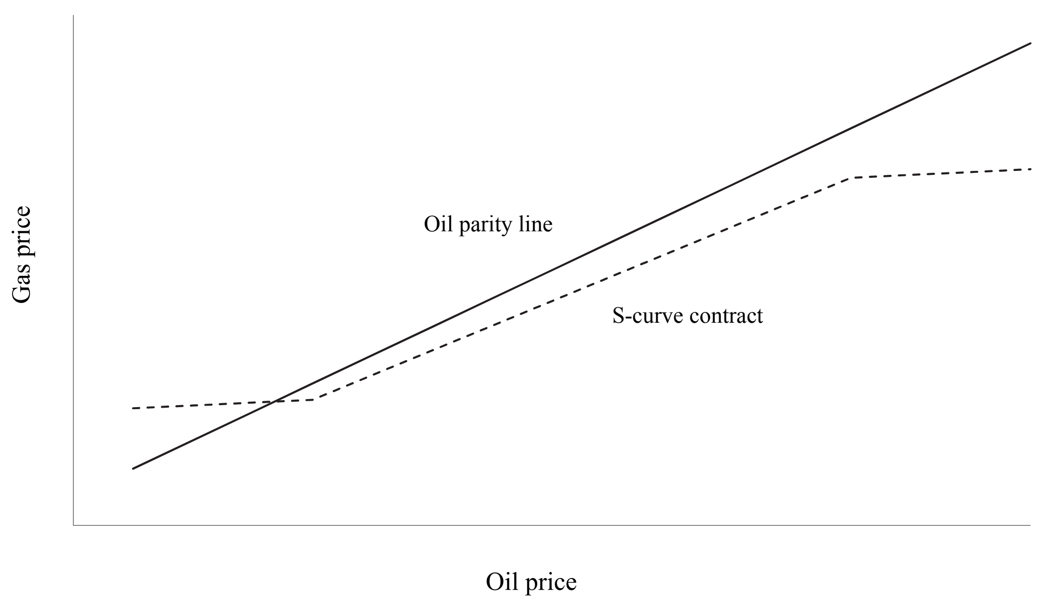
Other potential new sources of natural gas supply include Mozambique, Tanzania, Iran, Venezuela and Nigeria. However, many of these countries have significant political issues which, in the short term at least, are likely to discourage customers from entering into substantial LNG supply contracts.

Pricing

LNG is typically sold under long term contracts of 20 years or more in duration to underpin the large capital investments and long development lead times of LNG projects. As a consequence, unlike oil, no global pricing benchmarks have developed for natural gas. However, the share of LNG sold on the spot market or under short term contracts has grown substantially in recent years to around one third of global LNG trade in 2013.

In Asia LNG contracts have generally been priced relative to the Japan custom cleared crude oil price, also known as the Japanese Crude Cocktail ("JCC"). The JCC is the average price of customs-cleared crude oil imports into Japan and is calculated on a monthly basis. The JCC typically moves in line with oil benchmark prices albeit with a time lag reflecting the time between the date of the trade and the date of the delivery. The typical LNG pricing structure is based on a formula called the "S-curve" which places a band around the price by establishing a type of cap and floor price:

LNG Pricing Structure



The gradient of the middle section of the S-curve primarily reflects the energy content of the gas relative to oil. A 16.7% gradient would reflect a contract at parity to the oil price (oil parity line). Typically, gas prices are at a discount to oil parity reflecting general market demand and supply dynamics and a small constant discount to account for shipping costs.

Recent market commentary has raised the potential for a shift from oil linked LNG pricing. Factors that might result in such a shift include an increase in volumes of LNG sold at spot prices, the growing availability of tradeable gas made possible by an increase in gas supply (e.g. United States shale gas) combined with increased capacity in pipeline infrastructure and the potential for United States exporters to be internationally competitive as a result of United States domestic gas trading at a discount to the equivalent oil price. However, these factors are unlikely to have a major impact in the short to medium term as the majority of existing contracts are long term, oil price-linked contracts.

4 Profile of Roc Oil Company Limited

4.1 Overview

ROC was formed in late 1996 as an oil and gas exploration company and listed on the ASX in August 1999, raising $150 million. Since its listing ROC has actively managed a portfolio of production, development and exploration assets in China, South East Asia, Australia, United Kingdom and Africa. In late 2008 ROC completed the takeover of ASX listed Anzon Australia Limited ("Anzon") and a merger with that company's major shareholder, AIM[8] listed Anzon Energy Limited.

Today, ROC operates in the upstream oil and gas industry. Its activities range from exploration and appraisal to development and production delivery in China, South East Asia, Australia and the United Kingdom. It is headquartered in Sydney and has a workforce of around 200 located in China, Australia and Malaysia. ROC had a market capitalisation of around A$315 million prior to the announcement of the Merger.

ROC owns a portfolio of oil and gas production, development and exploration assets with proved and probable reserves (2P) of 17.4mmboe and contingent resources (2C) of 33.7mmboe at 1 January 2014 as summarised below:

ROC – Portfolio of Oil and Gas Assets

Location/ Asset	Interest	Status	2P Reserves (mmboe)	2C Resources (mmboe)
China				
Zhao Dong Joint Venture	C/D Fields: 24.5% C4 Field: 11.667% Zhanghai/Chenghai: 39.2%	Production/Development	3.7	4.6
Block 09/05	100.0%	Exploration	-	-
Beibu Gulf Joint Venture	19.6%	Production/Development	4.7	-
	40.0%	Exploration/Appraisal	-	1.1[9]
Malaysia				
D35/D21/J4 PSC	30.0%[10]	Production/Development	5.2	23.9
Myanmar				
Block M07[11]	59.375%	Exploration	-	-
Australia				
Cliff Head	42.5%	Production	2.2	2.3
L14 (Jingemia)	0.25%	Production	nmf[12]	nmf
United Kingdom				
Blane	12.5%	Production	1.3	0.7
Enoch/J1	12.0%	Production	0.3	1.1
Total			**17.4**	**33.7**

Source: ROC

In addition, ROC has a 48% interest in Malaysian company BC Petroleum Sdn Bhd ("BC Petroleum"). BC Petroleum is party to a risk service contract[13] with Petroliam Nasional Berhad ("PETRONAS") for the pre-development and development of the Balai Cluster Fields which are marginal oilfields located offshore Sarawak.

ROC's assets are described in more detail in Section 4.6 of this report.

8 Alternative Investment Market of the London Stock Exchange.
9 Updated by ROC on 30 May 2014 and assuming CNOOC exercises its right to participate up to 51%.
10 Following the farm out of a 20% participating interest to Dialog Resources Sdn Bhd as announced on 30 May 2014.
11 Subject to ROC board approval and signing of a production sharing contract.
12 nmf = not meaningful
13 A petroleum arrangement implemented in Malaysia with the objective of monetising marginal fields.

4.2 Financial Performance

The second half of 2008 was a difficult period as ROC dealt with the implications of the global financial crisis (including the collapse in the oil price) and completion of its acquisition of Anzon. The changed operating environment resulted in material asset impairments at 31 December 2008 and the refocussing of ROC's operations on China, South East Asia and Australia. Although total production has fallen, ROC's profitability has strengthened over the last five years in line with higher oil prices and as a consequence of active cost management:

ROC – Financial Performance (US$ millions)					
	Year ended 31 December				
	2009 actual	2010 actual	2011 actual	2012 actual	2013 actual
Production (mmboe)	*3.7*	*2.7*	*2.7*	*2.4*	*2.7*
Production (boepd)	*10,034*	*8,483*	*7,527*	*6,445*	*7,263*
Sales volume (mmboe)	*3.6*	*3.0*	*2.6*	*2.1*	*2.4*
Average realised oil price ($/bbl)	*57.0*	*78.6*	*110.9*	*113.6*	*104.6*
Production costs[14] ($/boe)	*17.7*	*21.9*	*17.1*	*15.1*	*19.3*
Amortisation of development expenditure ($/boe)	*24.8*	*24.8*	*30.8*	*30.0*	*26.7*
Development and exploration expenditure ($)	*72.1*	*54.1*	*46.7*	*94.3*	*76.7*
Sales revenue	**204.5**	**235.4**	**285.8**	**242.1**	**251.0**
EBITDAX[15]	**114.0**	**135.3**	**180.4**	**165.0**	**152.5**
Exploration costs written off	(7.1)	(20.5)	(13.5)	(18.1)	(16.5)
EBITDA[16]	**106.9**	**114.8**	**166.9**	**146.9**	**136.0**
Depreciation	(0.7)	(0.7)	(0.8)	(0.8)	(0.4)
Amortisation of development expenditure	(91.0)	(76.9)	(84.5)	(70.9)	(70.8)
EBIT[17]	**15.2**	**37.2**	**81.6**	**75.2**	**64.8**
Finance costs (net)	(9.4)	(2.0)	(5.8)	(2.6)	(3.7)
Significant and non-recurring items	(109.5)	(28.7)	4.9	10.1	0.6
Operating profit before tax	**(103.7)**	**6.5**	**80.7**	**82.7**	**61.7**
Income tax expense[18]	(11.7)	(42.4)	(53.0)	(21.7)	(16.5)
NPAT[19] attributable to ROC shareholders	**(115.4)**	**(35.9)**	**27.7**	**61.0**	**45.2**
Statistics					
Basic earnings per share	*(17.9)¢*	*(5.0)¢*	*3.9¢*	*8.9¢*	*6.6¢*
Sales revenue growth	*(42.9)%*	*15.1%*	*21.4%*	*(15.3)%*	*3.7%*
EBITDAX margin	*55.7%*	*57.5%*	*63.3%*	*68.2%*	*60.8%*
EBITDA margin	*52.2%*	*48.8%*	*58.5%*	*60.7%*	*54.2%*
EBIT margin	*7.4%*	*15.8%*	*28.7%*	*31.1%*	*25.8%*

Source: ROC and Grant Samuel analysis

Sales revenue primarily represents oil sales, with Cliff Head and Zhao Dong together accounting for around 70% of revenue over the five year period.

Significant and non-recurring items include:

14 Production costs include royalties and other levies which mainly relate to the Chinese Special Oil Income Levy which is levied on the price of oil over a certain threshold.

15 EBITDAX is earnings before net finance costs, tax, depreciation and amortisation, other income (net), significant and non-recurring items and exploration costs written off.

16 EBITDA is earnings before net interest, tax, depreciation and amortisation, other income (net) and significant and non-recurring items.

17 EBIT is earnings before net interest, tax, other income (net) and significant and non-recurring items.

18 Including petroleum resources rent tax in Australia.

19 NPAT is net profit after tax.

ROC – Significant and Non-Recurring Items (US$ millions)					
	Year ended 31 December				
	2009	2010	2011	2012	2013
Gain on sale of exploration and development assets	8.1	15.7	-	10.3	8.0
Derivative losses (net)	(37.0)	(9.1)	(13.1)	(0.9)	-
Impairment of oil and gas/exploration assets	(82.1)	(7.6)	18.6	-	-
Loss on sale of securities	(5.6)	-	-	-	-
Litigation settlement	-	(16.0)	-	-	-
Foreign currency gain/(loss) on subsidiary liquidation	-	(9.5)	-	4.7	-
Impairment of investment in BC Petroleum	-	-	-	-	(6.9)
Foreign exchange gains/(losses) (net)	6.0	(2.2)	(0.6)	(0.6)	(0.5)
Other	1.1	-	-	(3.4)	-
Total	**(109.5)**	**(28.7)**	**4.9**	**10.1**	**0.6**

ROC's effective tax rate fluctuates depending on asset performance and corporate activity. Since 2011 it has been around 26-27% reflecting tax paid in relation to the Chinese, United Kingdom and Australian producing assets.

Set out below is an analysis of ROC's sales revenue and gross profit by producing interest:

ROC – Financial Performance by Producing Interest (US$ millions)					
	Year ended 31 December				
	2009 actual	2010 actual	2011 actual	2012 actual	2013 actual
Production volume (mmboe)					
- Zhao Dong Joint Venture	*1.7*	*1.6*	*1.7*	*1.6*	*1.5*
- Beibu Gulf Joint Venture	-	-	-	-	*0.6*
- Cliff Head	*0.5*	*0.6*	*0.4*	*0.5*	*0.4*
- Blane	*0.5*	*0.4*	*0.5*	*0.3*	*0.2*
- Enoch/J1	*0.3*	*0.2*	*0.1*	-	-
- Divested and other interests	*0.7*	*0.3*	-	-	-
Total	***3.7***	***3.1***	***2.7***	***2.4***	***2.7***
Sales revenue					
- Zhao Dong Joint Venture	90.2	112.4	168.4	157.4	134.6
- Beibu Gulf Joint Venture	-	-	-	-	57.2
- Cliff Head	30.3	43.2	43.8	54.0	41.1
- Blane	30.7	35.0	57.2	23.6	18.1
- Enoch/J1	1z	15.3	11.0	2.5	-
- Divested and other interests	37.0	29.5	5.4	4.6	-
Total sales revenue	**204.5**	**235.4**	**285.8**	**242.1**	**251.0**
Gross Profit					
- Zhao Dong Joint Venture	16.7	32.1	49.3	57.5	43.7
- Beibu Gulf Joint Venture	-	-	-	-	29.0
- Cliff Head	11.0	21.5	16.4	33.3	21.6
- Blane	17.0	20.3	31.8	15.0	9.0
- Enoch/J1	9.5	10.0	8.5	(1.5)	(7.2)
- Divested and other interests	(18.8)	(14.8)	2.0	1.9	-
Total gross profit	**35.4**	**69.1**	**108.0**	**106.2**	**96.1**
Reconciliation to EBITDAX					
Addback: Amortisation of development expenditure	*91.0*	*76.9*	*84.5*	*70.9*	*70.8*
Less: Corporate overheads (net)	*(12.4)*	*(10.7)*	*(11.6)*	*(12.0)*	*(14.4)*
EBITDAX (as above)	*114.0*	*135.3*	*180.9*	*165.0*	*152.5*

Source: ROC and Grant Samuel analysis

The operating performance of each of ROC's producing interests is discussed in Section 4.6 of this report.

Corporate overheads (net) represent the costs incurred by ROC that are not recovered from projects including head office costs and public company costs.

Outlook

ROC has not publicly released earnings forecasts for the year ending 31 December 2014 or beyond. However, on 26 February 2014 ROC provided operational guidance for 2014 (albeit excluding any allowance for the D35/D21/J4 PSC farm in) as follows:

- production of 6,500-7,500boepd (net ROC share);
- production costs of <$21.00/bbl (excluding contribution to abandonment fund); and
- development and exploration expenditure of <$60 million (including funding to BC Petroleum).

4.3 Financial Position

Since 2008, ROC has paid down borrowings and funded its exploration and development activities primarily from cash from operations and asset sales. ROC's financial position as at 31 December 2013 is summarised below:

ROC – Financial Position (US$ millions)	
	As at 31 December 2013 actual
Trade and other receivables	32.4
Inventories	2.1
Trade, other payables and employee provisions	(52.1)
Net working capital	**(17.6)**
Oil and gas assets (net)	227.2
Property, plant and equipment (net)	0.9
Exploration and evaluation expenditure	0.6
Investment in BC Petroleum (48%)	67.2
Deferred tax liabilities (net)	(0.5)
Employee provisions (non current)	(1.2)
Restoration provision	(75.4)
Total funds employed	**201.2**
Cash and deposits	65.1
Net assets attributable to ROC shareholders	**266.3**
Statistics	
Shares on issue at period end (million)	*686.5*
Net assets per share	*$0.39*

Source: ROC and Grant Samuel analysis

Oil and gas assets (net) of $227.2 million represent ROC's investment in producing assets net of accumulated amortisation (i.e. there were no assets under development at year end).

ROC divested its 50% interest in the Basker-Manta-Gummy project ("BMG Project") project in Australia effective 1 January 2014 for an upfront cash payment of A$1 million (subject to working capital adjustments)[20] and a A$5 million contingent cash payment, subject to first hydrocarbons from a commercial development. ROC will recognise a net profit on sale of BMG Project of approximately $32 million (subject to working capital adjustment, before and after tax) reflecting the reversal of the provision for abandonment at 31 December 2013.

ROC's 48% investment in BC Petroleum represents its interest in the Balai Cluster RSC. This investment is equity accounted and at 31 December 2013 comprised equity with a book value of $25.9 million (after an impairment of $6.9 million relating to non recoverable expenditure) and a loan of $41.3 million. Cash contributions are initially made as a loan to BC Petroleum and subsequently converted to equity. BC Petroleum is described in Section 4.6.8.

[20] Received May 2014.

At 31 December 2013, ROC:

- had provisions for restoration totalling $75.4 million ($42.7 million excluding the restoration provision relating to BMG Project);
- had an amortising secured bank facility of $66.5 million available. This facility is undrawn and matures in June 2015;
- had no derivative financial instruments in place;
- disclosed capital commitments totalling $35.8 million ($21.1 million within 12 months) reflecting ROC's commitment to exploration expenditure for Block 09/05; and
- disclosed contingent liabilities in relation to obligation (in accordance with normal industry practice) to meet expenditure commitments of a defaulting party to joint venture agreements (typically on a proportional basis).

Under the Australian tax consolidation regime, ROC and its wholly owned Australian resident entities have elected to be taxed as a single entity. At 31 December 2013, ROC had carried forward income tax losses of approximately $210 million (tax shield $67.1 million), none of which were recognised in the balance sheet. These losses primarily relate to ROC's interest in BMG Project which was divested effective 1 January 2014. These losses are unlikely to be recouped by ROC in the foreseeable future. In addition, ROC had carried forward Australian capital losses of approximately A$85.8 million and approximately A$34 million of accumulated franking credits.

Since 31 December 2013, ROC has announced that it had farmed into the D35/D21/J4 PSC in Malaysia and that a joint venture in which it has a 59.375% interest had been awarded a production sharing contract for Block M07 in Myanmar. Further details of these assets and ROC's investment are set out in Sections 4.6.4 and 4.6.7 of this report respectively.

4.4 Capital Structure and Ownership

ROC has 687,618,400 ordinary shares on issue. There are around 16,000 registered shareholders in ROC. The top 20 shareholders account for around 72% of the ordinary shares on issue and are principally institutional nominee or custodian companies. ROC has a significant retail investor base with around 80% of registered shareholders holding less than 10,000 shares but this represents around 5% of the shares on issue. ROC shareholders are predominantly Australian based investors (around 82% of registered shareholders and 97% of shares on issue). ROC has one substantial shareholder, Allan Gray Australia Pty Limited ("Allan Gray") (which manages funds on behalf of clients) which has a 20.06% interest[21]. Directors and executives of ROC are estimated to account for less than 1% of the shares on issue.

In addition, ROC has the following securities over unissued ordinary on issue:

- 300,000 options issued under the Executive Share Option Plan;
- 18,243,358[22] rights issued under the Long Term Incentive Plan ("LTI Rights"); and
- 1,886,476[23] deferred rights issued under the Short Term Incentive Plan ("STI Rights").

Historically, ROC operated two share option plans. These plans were replaced in 2010 and the only options currently outstanding were granted under the Executive Share Option Plan. Under this plan, 30% of options granted vest after two years, an additional 30% vest after three years and the remainder vest after four years. All options expire six years after they are granted and lapse on termination of employment (unless determined otherwise by the board). Of the options granted to an employee, 50% are performance options (only exercisable if certain share performance

[21] Based on 137,906,663 shares disclosed in a substantial shareholder notice dated 9 September 2011.

[22] Excluding 1,180,841 LTI Rights approved at the ROC annual general meeting on 27 May 2014 but not yet granted.

[23] Excluding 387,209 STI Rights approved at the ROC annual general meeting on 27 May 2014 but not yet granted.

benchmarks are met) and 50% are price options (which require share performance measures to be met). Each option on issue is exercisable into one ordinary share and has no dividend entitlement or voting right. ROC has 300,000 options on issue with a weighted average exercise price of A$0.73 (of which 150,000 are currently exercisable) and which lapse on 23 December 2014.

The Long Term Incentive Plan was reviewed and updated in 2013 and is a variable performance based equity plan to reward eligible employees for delivering sustained performance over a multi-year performance period. The plan provides for the grant of rights to acquire ROC ordinary shares for nil consideration if certain performance conditions are met within defined periods. The rights lapse when a participant ceases to be employed by ROC other than in certain circumstances. The board has discretion to determine that unvested rights will lapse if it is not satisfied with certain performance related matters. LTI Rights awarded to executives (other than the CEO Alan Linn) prior to May 2013 have three tiers of performance conditions while LTI Rights issued to the CEO during 2013 and generally from 2014 onwards have two tiers of performance conditions. The LTI Rights on issue are summarised below:

ROC – LTI Rights on Issue

Grant Date	Vesting Date	On Issue
16 December 2011	16 December 2014	4,400,000
29 February 2012	1 March 2015	200,000
13 September 2012	13 September 2015	500,000
1 March 2013	1 March 2016	5,615,000
15 May 2013	1 March 2016	977,358
31 May 2013	25 May 2016	150,000
6 September 2013	6 September 2016	150,000
18 March 2014	31 December 2016	6,250,000
Total		**18,243,358**

Source: ROC

ROC operates a Short Term Incentive Plan which is a variable performance based cash and deferred equity incentive plan designed to reward senior executives and eligible employees for performance, following the end of the financial year. The deferred equity component is awarded in the form of STI Rights that may be converted into ordinary shares subject to the satisfaction of performance conditions and board approval. The only performance condition is that the participant remains continuously employed by ROC up to the end of a defined deferral period (generally one to three years). STI Rights on issue are summarised below:

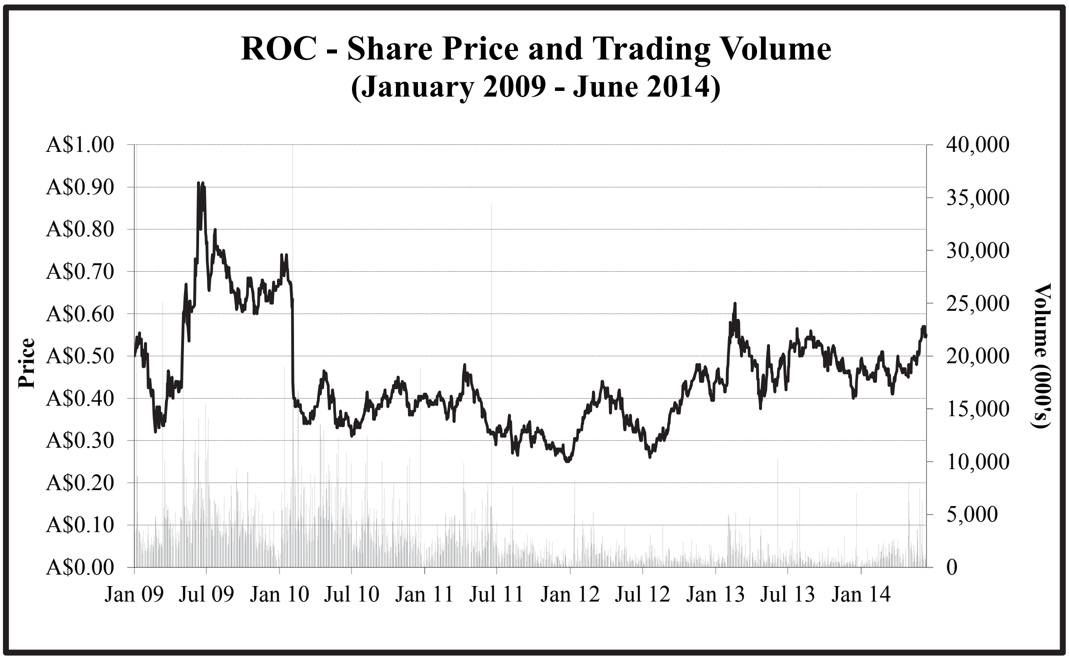
ROC – STI Rights on Issue

Grant Date	Expiry Date	Vesting Date	On Issue
15 May 2013	31 December 2014	31 December 2014	142,160
15 May 2013	31 December 2015	31 December 2015	35,540
29 January 2014	31 December 2015	31 December 2014	1,110,702
29 January 2014	31 December 2015	31 December 2015	598,074
Total			**1,886,476**

Source: ROC

4.5 Share Price Performance

ROC shares commenced trading on the ASX in August 1999 above the A$2.00 subscription price but over the period to 2005 generally traded below that level. The share price followed the stockmarket higher during the period 2005 to 2007 (to above A$3.00) and then lower following the commencement of the global economic downturn in late 2007. ROC shares closed at A$0.50 on 31 December 2008. The following graph illustrates the movement in the ROC share price and trading volumes since 1 January 2009:



Source: IRESS

Note: On two days in this period more than 40 million shares traded but are not shown on the graph (7 January 2009 when Nexus Energy Limited divested the ROC shares it had received on acceptance of ROC's takeover of Anzon and 3 February 2010 when ROC announced a material downgrade in 2P reserves at the BMG Project).

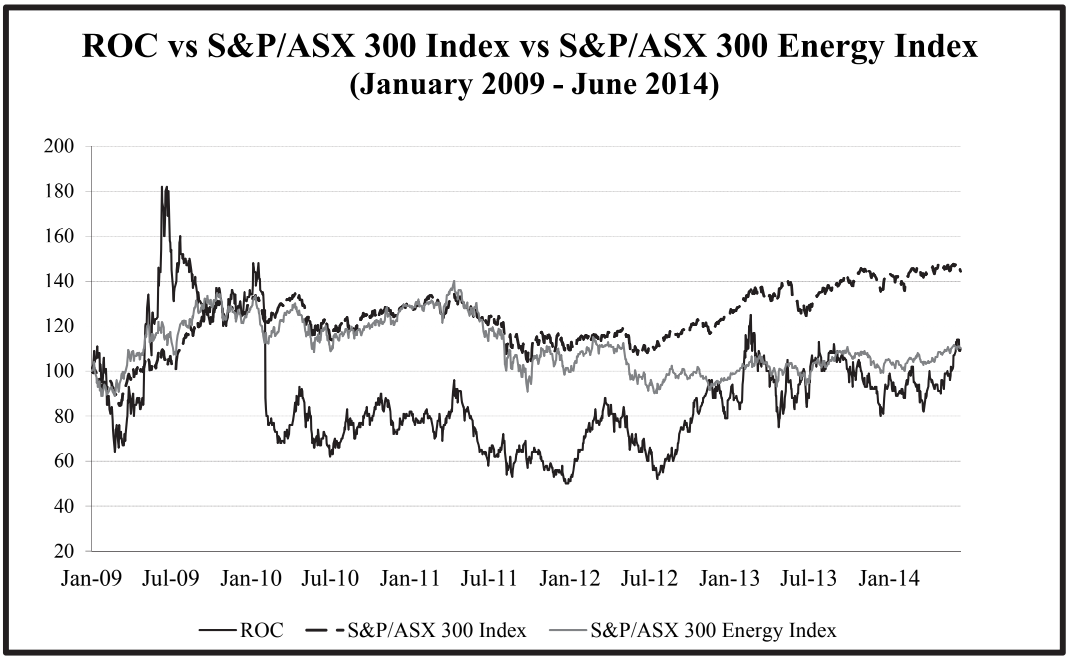
After declining further to around A$0.35 in March 2009, the ROC share price recovered to trade in the range A$0.60-0.70 during the remainder of 2009. However, following the announcement of a material reduction in 2P reserves at the BMG Project, the share price dropped sharply back to below A$0.40. Subsequently, ROC shares traded in the range A$0.30-0.40 (supported in part by an A$10 million on market share buyback from May 2011 to December 2011) until January 2013 when, following the release of its activity report for the last quarter of 2012, it rose above A$0.50. After gradually declining ROC shares traded broadly in the range of A$0.40-0.50 during the remainder of 2013 (at a VWAP[24] of A$0.50).

During 2014, prior to the announcement of the Merger on 29 April 2014, ROC shares traded in the range A$0.41-0.52 (at a VWAP of A$0.46) and closed at A$0.455 on 23 April 2014 (the last day ROC shares were traded prior to the announcement). Since the announcement, ROC shares have traded in the range A$0.445-0.570 (at a VWAP of A$.506) and closed at A$0.55 on 13 June 2014.

ROC is not a highly liquid stock. Average weekly volume over the twelve months prior to the announcement of the Merger represented approximately 0.7% of average shares on issue or annual turnover of around 35% of total average issued capital.

ROC is a member of various indices including the S&P/ASX 300 Index and the S&P/ASX 300 Energy Index. Its weighting in these indices is small at around 0.03% and 0.38% respectively. The following graph illustrates the relative performance of ROC shares since January 2009:

[24] VWAP = volume weighted average price

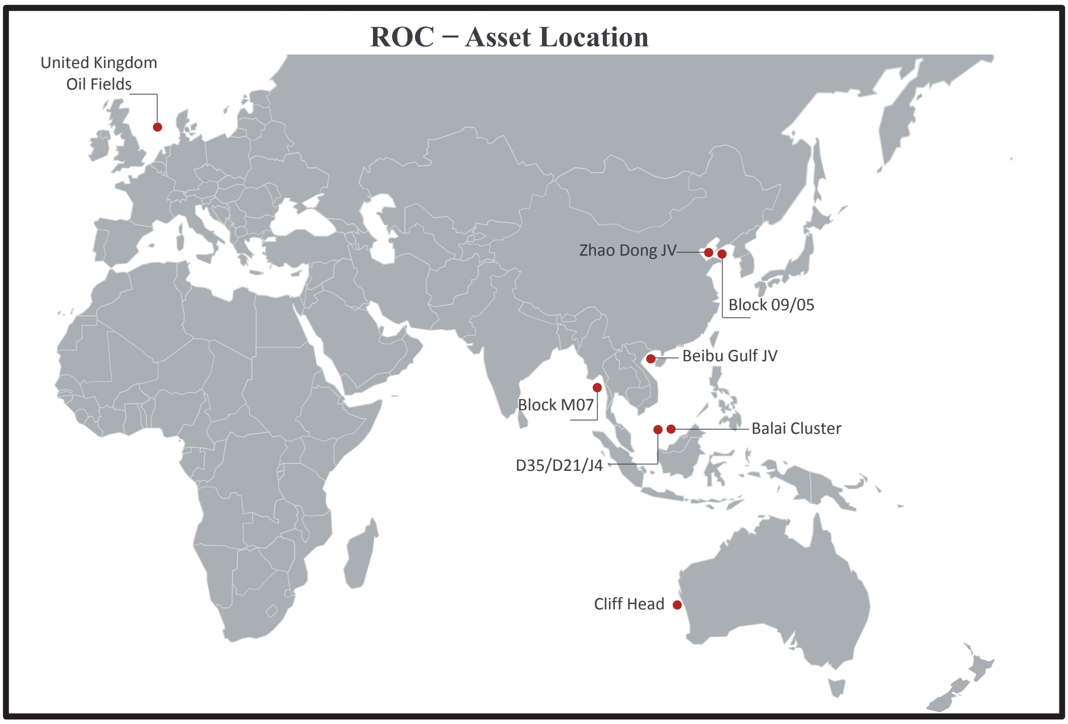


Source: IRESS

ROC shares substantially underperformed both indices on the announcement of the BMG Project reserve downgrade in January 2010. From April 2010 to September 2012 ROC shares generally mirrored movements in the indices but displayed greater volatility. Over the next 12 months, while the indices traded broadly in line with each other, ROC shares outperformed. Since September 2013 the S&P/ASX Energy Index has generally underperformed the wider market with ROC mirroring that trend (albeit with greater volatility).

4.6 Operations

ROC primarily produces oil from offshore assets. Its assets are focussed on Australia, South East Asia and China as shown below and described in the following sections:



Source: ROC

4.6.1 Beibu Gulf Joint Venture

The Beibu Gulf Joint Venture comprises Horizon (55%), ROC (40%) and Majuko Corporation (5%). The joint venture holds Block 22/12 under a petroleum contract originally entered into by Horizon with CNOOC in December 1999 under which CNOOC has a right to participate in up to 51% of any development. Block 22/12 is located in the Beibu Gulf in the South China Sea in approximately 40 metres of water and is located near several known oil fields. The term of the contract is for 30 years with a 15 year production period.

ROC farmed in and took over the operatorship of Block 22/12 in 2002. Two of the three exploration wells drilled in the period 2002-2006 discovered oil and work on a development plan for the WZ 6-12 and WZ 12-8 West Oil Fields commenced. In August 2010 the joint venture entered into a development agreement supplementary to the petroleum contract whereby commercial arrangements for the development were agreed and CNOOC assumed a 51% interest in the development and became its operator. Consequently the ownership interests in the WZ 6-12 and WZ 12-8 West Oil Fields became CNOOC (51%), Horizon (26.95%), ROC (19.6%) and Majuko Corporation (2.45%).

Ownership interests in continuing exploration and other potential developments in Block 22/12 are Horizon (55%), ROC (40%) and Majuko Corporation (5%), subject to CNOOC's right to participate in up to 51% of any development. ROC remains the operator for the purposes of exploration in Block 22/12. In late 2012 additional near field prospects were identified and a feasibility study into the potential development of the WZ 12-8 East Field is underway.

ROC's economic interest in the reserves and resources at 1 January 2014 are:

Beibu Gulf – ROC Economic Interest in Reserves and Resources at 1 January 2014

Category	WZ 6-12 / WZ 12-8 West Oil Fields			WZ 12-8 East Field		
	Oil (mmbbl)	Gas (bcf)	Total (mmboe)	Oil (mmbbl)	Gas (bcf)	Total (mmboe)
2P	4.7	-	4.7	-	-	-
2C	-	-	-	1.1[9]	-	1.1[9]
Best estimate of prospective risked resources	-	-	-	0.6	-	0.6

Source: ROC

Final investment decision for the development of the WZ 6-12 and WZ 12-8 West Oil Fields was reached in February 2011. Production commenced in March 2013 with 15 wells in production by August 2013. Production rates are currently around 13,000bopd with five wells still on natural flow. The 15 year production period under the petroleum contract for the fields will end in 2028.

The development incorporates 15 producing wells from two remote wellhead platforms tied back to a processing platform. The processing platform is located adjacent to the existing CNOOC owned and operated WZ 12-1A and WZ 12-1PAP platforms. The processing platform is a shared facility, processing liquids from other fields. Each field has its own process train which can handle up to 20,000bopd. The processing platform treats the mixed streams of crude oil, associated gas and water from the wellheads via a conventional three stage physical separation process. Separated oil is then sent to a buffer tank for storage and export. Oil is transported via an existing CNOOC owned pipeline to CNOOC's storage and export terminal on Weizhou Island, 34 kilometres away. All oil produced is sold to CNOOC under a sale agreement and, given the viscosity of the oil, the price received is at a discount to the Brent crude oil price.

ROC's share of revenue from commencement of production in March 2013 to 31 December 2013 was $57.2 million from which it earned gross profit of $29 million (see Section 4.2).

Work is continuing on a development plan for the WZ 12-8 East Field and is expected to be completed in the third quarter of 2014. It is proposed that the development will consist of a leased mobile production platform, connected by pipelines up to three production wells, with a further four or five wells and a permanent wellhead platform depending on production performance. Expected recoverable oil could be in the order of 4-5mmboe. A feasibility study is expected to be completed by the end of 2014.

4.6.2 Zhao Dong Joint Venture

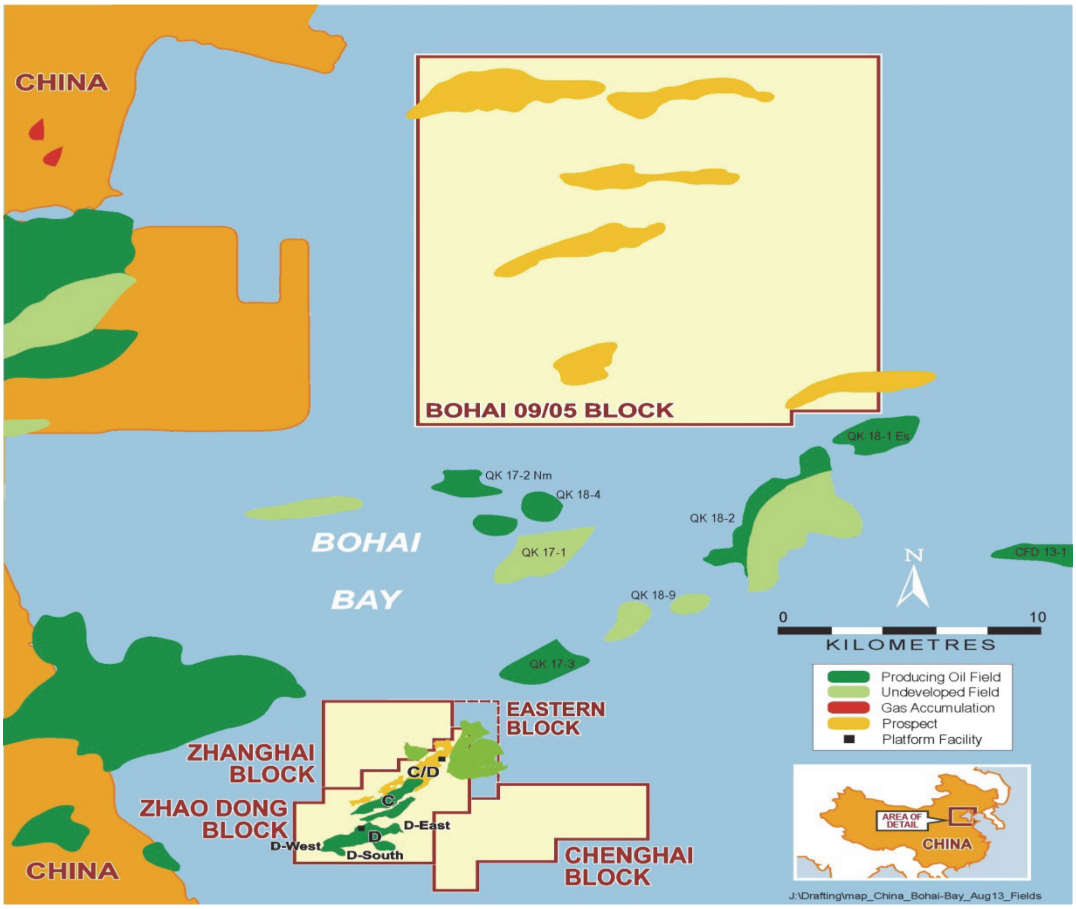
The Zhao Dong Joint Venture comprises ROC, PetroChina Company Limited ("PetroChina") and Sinochem Petroleum Exploration and Production Co., Ltd. It owns and operates a number of areas (classified as separate fields for royalty and fiscal purposes) located in the Gulf of Bohai, north east China, for which ROC is the operator.

The Zhao Dong Petroleum Contract was awarded in February 1993 and allows for 15 years of commercial production. It encompasses:

- the C Field and D Field (referred to as the C/D Fields), in which ROC has a 24.5% working interest; and
- the C4 Field in which ROC has an 11.667% unitised interest.

In March 2011, the joint venture was awarded two new offshore areas adjoining the Zhao Dong Block (the Zhanghai and Chenghai Blocks) with the aim of commercialising near field discoveries and encouraging further exploration activity. The existing Zhao Dong Petroleum Contract was modified to include the two blocks and to allow the term to be extended when and as necessary to accommodate any new production from these blocks. Any commercial development of the Zhanghai and Chenghai Blocks would utilise the existing Zhao Dong facilities. The initial work programme for the Zhanghai and Chenghai Blocks included the drilling of two appraisal wells from an existing Zhao Dong platform over a two year period. In August 2012 production commenced from the first appraisal well in the Zhanghai Block and PetroChina exercised its right to participate in the new blocks. As a consequence, ROC's interest in these blocks reduced to 39.2%. The second appraisal well in the Zhanghai Block was drilled during 2012 but came in below expectation.

The interests of the Zhao Dong Joint Venture and ROC's 's interest in exploration Block 09/05 (as described in Section 4.6.2) are located as follows in the Gulf of Bohai:



Source: ROC

At 1 January 2014 ROC's economic interest in the reserves and resources of the Zhao Dong Joint Venture are as follows:

Zhao Dong – ROC Economic Interest in Reserves and Resources at 1 January 2014			
Category	**Oil (mmbbl)**	**Gas (bcf)**	**Total (mmboe)**
2P	3.6	0.9	3.7
2C	4.4	1.0	4.6
Best estimate prospective risked resources	0.6	1.1	0.8

Source: ROC

Production commenced in September 2003 from the C/D Fields and in 2008 from the C4 Field and from further extension into the C/D Fields. The C/D Field development comprises four linked platforms, two for drilling and accommodation (ODA/B) and two for production and processing (OPA/B). The C4 Field satellite development comprises a drilling platform (CP2), a bridge linked pipeline terminal platform (PT1) and production and water injection pipelines linked back to the main OPA/B facility. A gas pipeline and oil pipeline link the offshore facilities to a nearby onshore oil terminal. The oil and gas is sold under a number of contracts with the oil price received generally at a small discount to the Brent crude oil price.

The Zhao Dong fields are mature and, although they have been subject to continuous development, production is in decline in the absence of material capital expenditure (as the Zhao Dong Petroleum Contract expires in September 2018 capital expenditure is being rationed).

An incremental development plan for the Zhao Dong Joint Venture was submitted to PetroChina in 2013 for review and approval. The plan includes operational and development activities to 2018 and, assuming an extension of the Zhao Dong Petroleum Contract, continuous development of the field from 2018 to 2023. Currently, there is no certainty that an extension to the petroleum contract will be granted.

ROC's share of production, sales and gross profit from the Zhao Dong Joint Venture for the last five years is summarised below:

Zhao Dong Joint Venture – ROC Share of Operating Performance (US$ millions)					
	Year ended 31 December				
	2009 actual	**2010 actual**	**2011 actual**	**2012 actual**	**2013 actual**
Production (mmboe)	*1.7*	*1.6*	*1.7*	*1.6*	*1.5*
Sales revenue	**90.2**	**112.4**	**168.4**	**157.4**	**134.6**
Production costs	(15.6)	(16.7)	(17.9)	(14.9)	(20.3)
Amortisation of development expenditure	(45.6)	(46.8)	(65.0)	(57.0)	(48.8)
Other costs	(12.3)	(16.8)	(36.2)	(28.0)	(21.8)
Gross Profit	**16.7**	**32.1**	**49.3**	**57.5**	**43.7**

Source: ROC (refer Section 4.2)

4.6.3 Block 09/05

Block 09/05 is a 335 square kilometre exploration licence located approximately 15 kilometres north of the Zhao Dong Block in Bohai Bay in water depths of 4-10 metres. ROC signed a petroleum contract with the China National Offshore Oil Corporation ("CNOOC") for a 100% interest in and operatorship of Block 09/05 in May 2012. Upon a successful discovery, CNOOC has a right to participate in up to 51% of any development.

Block 09/05 exhibits similar characteristics to the Zhao Dong Block. Previous exploration activity within the block included wide-spaced 2D and limited 3D seismic acquisition. Two exploration wells were drilled on the block prior to 3D seismic processing. The wells confirmed the presence of sands but were assessed to be off structure.

The minimum work commitment in the initial three year exploration period includes the acquisition of 3D seismic and the drilling of exploration wells. On completion of that phase, there are two further optional two year exploration periods with additional commitments.

ROC completed a 3D seismic campaign covering 162 square kilometres in Block 09/05 in September 2013. Seismic processing has been completed and interpretation of the data is progressing. Planning for an exploration drilling programme in the second quarter of 2014 is underway including the pre-permitting and procurement of long lead items. ROC's best estimate risked prospective resources within Block 09/05 are 30.3mmboe (100%) with revisions expected on completion of the 3D seismic evaluation. Gross expenditure on Block 09/05 to 31 December 2013 was $12.5 million.

ROC entered into a farm out option agreement with Horizon in relation to a 40% working interest in Block 09/05 in October 2013. In light of the Merger, Horizon has not exercised this option and it has lapsed.

4.6.4 D35/D21/J4 PSC

D35, D21 and J4 are producing oil and gas fields (combined oil rate of around 10,000bopd and gas sales of around 17mmscf/day) located offshore Sarawak (East Malaysia) in water depths of approximately 50 metres. D35 is the largest field with the longest production history and D21 and J4 are satellite producing assets. These fields are subject to a production sharing contract[25] ("PSC") between PETRONAS as owner and its exploration and production subsidiary, PETRONAS Carigali Sdn Bhd ("PETRONAS Carigali") as operator.

The D35, D21 and J4 fields are mature and for a variety of technical and commercial reasons have underperformed. They represent a significant brownfield development project. The proposed redevelopment project comprises two parts:

- **Production Enhancement Activities**: which are designed to increase the oil production rate and enhance the production potential through a series of intervention activities and facility debottlenecking projects for an estimated capital investment of up to $250 million (with a minimum work commitment of $70 million). These activities commenced in early 2014 and are expected to contribute about 17.4mmboe of 2P gross economic interest. Operating costs are expected to be $22/boe; and
- **Enhanced Oil Recovery Activities**: which contemplate an expansion of production and the overall recovery potential of the fields by accessing 2C contingent resources of 79.6mmboe (gross economic interest). These activities are subject to a field development plan decision process planned for 2015 following completion of a series of studies designed to prove the reservoirs' responses to re-pressurisation and tertiary recovery technologies. The minimum work commitment is $50 million.

The project also offers exploration opportunities (ROC's initial assessment of gross estimated prospective risked resources is 24mmboe) but this potential is to be further refined during the period of the redevelopment project.

On 1 April 2014 ROC announced that it had farmed into the D35/D21/J4 PSC. Under the terms of the farm in:

- ROC paid $25 million[26] to acquire a 50% participating interest and has taken on capital commitments of $80 million spread over the redevelopment project;
- the redevelopment project is to be delivered by a team comprising personnel from ROC and PETRONAS Carigali;

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25 A contract signed between a government entity and a resource extraction company concerning how much of the resource extracted from the asset each party will receive.

26 To be paid in four annual instalments of $6.25 million. The first payment was made in May 2014.

- PETRONAS Carigali will continue as operator of the production sharing contract (responsible for operations and maintenance of facilities) and retain a 40% participating interest; and
- ROC has been appointed development manager for the redevelopment project, responsible for subsurface management, well engineering, new facilities projects and project execution.

On 30 May 2014 ROC announced its intention to farm out a 20% participating interest in the D35/D21/J4 PSC to Dialog Resources Sdn Bhd ("DIALOG"), resulting in a net interest of 30%. The farm out is subject to PETRONAS approval, joint venture approval and completion of documentation.

ROC's estimated economic interest in reserves and resources of the D35/D21/J4 PSC at 1 January 2014 (based on a 30% interest) are as follows:

D35/D21/J4 – ROC Economic Interest in Reserves and Resources at 1 January 2014

Category	Oil (mmbbl)	Gas (bcf)	Total (mmboe)
2P	4.1	6.9	5.2
2C	22.1	10.3	23.9
Best estimate prospective risked resources	7.2	-	7.2

Source: ROC

The estimates set out in the section above are based on ROC's feasibility study of the fields or development area. Therefore, the estimates should not be construed as being estimates supported or endorsed by PETRONAS.

4.6.5 Cliff Head

The Cliff Head oil field is located in licence area WA-31-L in the Perth Basin, 10 kilometres offshore Western Australia. ROC holds a 42.5% interest in Cliff Head and is the operator. AWE Limited holds a 57.5% interest. At 1 January 2014 ROC's share of 2P reserves was 2.2mmboe, 2C resources was 2.3mmboe and best estimate prospective risked resources was 0.5mmboe.

Production commenced in May 2006 from six sub-sea production wells and water injection commenced in July 2008 with two water injection wells. Oil is produced to an unmanned platform, transported by a sub-sea pipeline to the Arrowsmith onshore processing plant and then trucked to BP's Kwinana Refinery. Cliff Head is a mature producing asset (with limited capital expenditure required) with an economic field life based on 2P reserves estimated to continue until 2027. ROC is currently assessing near field potential to take advantage of the existing facilities.

ROC's share of production, sales and gross profit from Cliff Head for the last five years is summarised below:

Cliff Head – ROC Share of Operating Performance (US$ millions)

	Year ended 31 December				
	2009 actual	2010 actual	2011 actual	2012 actual	2013 actual
Production (mmboe)	*0.5*	*0.6*	*0.4*	*0.5*	*0.4*
Sales revenue	**30.3**	**43.2**	**43.8**	**54.0**	**41.1**
Production costs	(9.6)	(11.7)	(20.8)	(12.6)	(13.5)
Amortisation of development expenditure	(9.7)	(10.0)	(6.9)	(8.1)	(6.1)
Other costs	-	-	(0.3)	-	(0.1)
Gross Profit	**11.0**	**21.5**	**16.4**	**33.3**	**21.6**

Source: ROC (refer Section 4.2)

4.6.6 L14 (Jingemia)

ROC has a 0.25% interest in Block L14 (Jingemia), an oil field in the Perth Basin offshore Western Australia. This block is operated by Origin Energy Limited. Operations at the site were suspended in December 2012 and at 31 March 2014 remain under care and maintenance pending a decision by the joint venture on its future.

4.6.7 United Kingdom

ROC's interests in the Blane and Enoch producing oil fields in the United Kingdom North Sea are legacy assets and considered non-core. ROC has a 12.5% unitised interest in Blane and a 12% unitised interest in Enoch. Both fields are operated by Talisman Sinopec Energy (UK) Limited, a joint venture between Talisman Energy Inc. ("Talisman") and Sinopec Group. J1 is a prospect in the Enoch licence. ROC's share of reserves and resources of the United Kingdom oil fields at 1 January 2014 are as follows:

United Kingdom – ROC Share of Reserves and Resources at 1 January 2014						
Field	Oil (mmbbl)		Gas (bcf)		Total (mmboe)	
	2P	2C	2P	2C	2P	2C
Blane	1.3	0.7	0.1	-	1.3	0.7
Enoch/J1	0.3	0.2	-	5.6	0.3	1.1
Total	**1.6**	**0.9**	**0.1**	**5.6**	**1.6**	**1.8**

Source: ROC

The Blane oil field straddles the United Kingdom-Norway median line in the southern part of the North Sea Central Graben. Production commenced in September 2007 from two sub-sea production wells tied back to the Ula platform. Gas lift was initiated in February 2009, ceased in July 2009 due to connection leaks and did not recommence until October 2010. Commercial production from Blane may be limited by the estimated life of the host facilities (2027) or any requirements for major expenditure. ROC's share of production, sales and gross profit from Blane for the last five years is as follows:

Blane – ROC Share of Operating Performance (US$ millions)					
	Year ended 31 December				
	2009 actual	2010 actual	2011 actual	2012 actual	2013 actual
Production (mmboe)	*0.5*	*0.4*	*0.5*	*0.3*	*0.2*
Sales revenue	**30.7**	**35.0**	**57.2**	**23.6**	**18.1**
Production costs	(3.4)	(5.1)	(4.4)	(3.9)	(3.6)
Amortisation of development expenditure	(11.4)	(9.2)	(9.6)	(5.1)	(4.3)
Other costs	1.1	(0.4)	(11.4)	0.4	(1.2)
Gross Profit	**17.0**	**20.3**	**31.8**	**15.0**	**9.0**

Source: ROC (refer Section 4.2)

The Enoch oil field straddles the United Kingdom-Norway median line in the southern part of the South Viking Graben. Development is by a single sub-sea horizontal production well tied back to the Brae-A platform. Production commenced in May 2007 and gas lift was initiated in January 2008. The field has been shut-in since January 2012 due to the failure of the subsea tree. This has been replaced and production is expected to resume in the second quarter of 2014. Commercial production from Enoch may be dictated by third party costs, the condition of the host facilities (2020) or if major expenditure is required. ROC's share of production, sales and gross profit from Enoch for the last five years is as follows:

Enoch – ROC Share of Operating Performance (US$ millions)					
	Year ended 31 December				
	2009 actual	2010 actual	2011 actual	2012 actual	2013 actual
Production (mmboe)	*0.3*	*0.2*	*0.1*	-	-
Sales revenue	**16.3**	**15.3**	**11.0**	**2.5**	-
Production costs	(1.6)	(1.4)	(1.0)	(2.6)	(7.1)
Amortisation of development expenditure	(5.2)	(3.3)	(2.0)	(0.2)	-
Other costs	-	(0.7)	0.4	(1.1)	(0.1)
Gross Profit	**9.5**	**10.0**	**8.5**	**(1.5)**	**(7.2)**

Source: ROC (refer Section 4.2)

4.6.8 BC Petroleum (48% interest)

BC Petroleum is a Malaysian company in which ROC has a 48% interest. BC Petroleum is party to a risk service contract[27] with PETRONAS for the pre-development and development of the Balai Cluster which comprises four marginal fields (Balai, Bentara, Spaoh and West Acis) located offshore Sarawak in approximately 50-60 metres of water. Under the contract PETRONAS is the owner of the Balai Cluster project (i.e. entitled to 100% of production volumes and retains the abandonment obligations) and BC Petroleum is the operator of the project. The other shareholders in BC Petroleum are DIALOG (32%) and PETRONAS Carigali (20%).

The Balai Cluster risk service contract was entered into in August 2011 and has a term of 15 years (to August 2026) unless otherwise extended or terminated by the parties. The contract contemplates two phases: pre-development (including geological and geophysical works, drilling and testing of appraisal wells and the procurement of related facilities and equipment) and, subject to agreement on project viability, development (including drilling of wells, installation of platforms, topsides and pipelines and tie in to existing infrastructure as appropriate).

Under the risk service contract BC Petroleum is to fund both the pre-development and development phases but will be entitled to reimbursement of capital and operating expenditure related to the project (as specified in the contract) when production commences and other performance criteria are met. In addition, during the development phase, BC Petroleum will be entitled to receive a remuneration fee (subject to actual performance).

During 2013 the pre-development phase was completed and a field development plan for the Bentara field was submitted to PETRONAS in December 2013. In March 2014 approval was received for the early production plan to develop the Bentara field. Full field development is subject to further approval based on information to be collected during the early production phase.

Prior to the pre-development phase under the risk service contract, two wells were drilled in the Bentara field and during pre-development two further wells were drilled from the Bentara-A wellhead platform. The early production phase of the Bentara field development will produce oil through the existing platform and two of the drilled wells. Production will be processed through the early production vessel ("EPV") Balai Mutiara and transferred to point of sale via a ship-to-ship transfer to a shuttle tanker. First commercial production from the field is expected during the second quarter 2014.

BC Petroleum has invested approximately $350 million of which $162 million was sourced from bank loans and the balance from shareholders. Early production field development is expected to be funded from cash flow and cost reimbursement under the risk service contract is anticipated to occur over the period from mid 2014 to the end of 2015. The bank debt is due for repayment by the end of 2014.

The estimates set out in the section above are based on ROC's feasibility study of the fields or development area. Therefore, the estimates should not be construed as being estimates supported or endorsed by PETRONAS.

4.6.9 Block M07 (Myanmar)

On 27 March 2014 ROC announced that a joint venture in which it has a 59.375% interest had been awarded a production sharing contract for shallow water exploration Block M07. Block M07 is approximately 13,000 square kilometres in size and is located in the Maottama Basin, offshore Myanmar. The block award includes a provision to undertake an 18 month environmental impact assessment and study period following which the joint venture has an option to proceed into a three year exploration work programme. This award is subject to finalisation of the contract terms with the Myanmar Ministry of Energy and ROC board approval. ROC's joint venture partners are Tap Oil Limited (35.625%) and Smart E&P International Ltd (5%).

[27] Under risk service contracts upfront investment is contributed by the contractor which is compensated by reimbursement of costs plus a remuneration fee for services provided. The remuneration fee is based on oil and gas production and the meeting of performance criteria.

5 Profile of Horizon Oil Limited

5.1 Overview

Horizon was formed in 1969 as an exploration and production company and was listed on the ASX as Bligh Oil & Minerals N.L. in June 1981. In October 2002, its name was changed to Horizon Oil N.L. and in February 2004 its status was changed to a company limited by shares. Since incorporation it has been involved in a range of resources activities and regions but since 2002 it has been focussed on petroleum exploration, development and production in south east Asia and Australasia.

Today, Horizon owns interests in China, New Zealand and PNG with proved and probable reserves (2P) of 15.9mmboe and contingent resources (2C) of 79.3mmboe at 1 January 2014 as summarised below:

Horizon – Portfolio of Oil and Gas Assets				
Location/ Asset[28]	**Interest**	**Status**	**2P Reserves (mmboe)**	**2C Resources (mmboe)**
Papua New Guinea				
PDL 10[29] (Stanley)	30.0%[30]	Development	3.4	20.4
PRL 21 (Elevala/Ketu)	27.0%[30]	Appraisal	-	57.4
PPL 259	35.0%[30]	Exploration	-	-
PPL 430	50.0%[31]	Exploration	-	-
PPL 372	90.0%[31]	Exploration	-	-
PPL 373	90.0%[31]	Exploration	-	-
China				
Beibu Gulf Joint Venture	26.95%	Production/Development	6.5	-
	55.0%	Exploration/Appraisal	-	1.5[32]
New Zealand				
PMP 38160 (Maari/Manaia)	10.0%	Production/Development Exploration/Appraisal	6.0	-
PEP 51313 (Matariki)	21.0%[33]	Exploration	-	-
Total			**15.9**	**79.3**

Source: Horizon

Horizon's assets are described in more detail in Section 5.6 of this report.

A key recent event for Horizon was the May 2013 announcement that it had entered into arrangements with Osaka Gas Co. Ltd of Japan ("Osaka Gas") in relation its PNG assets as follows:

- the sale to Osaka Gas of 40% of Horizon's interests in PRL 4 (now PDL 10), PRL 21 and PPL 259 ("the Osaka Gas transaction"):
  - Osaka Gas paid a $20 million cash deposit with a further $54 million (plus completion adjustments) payable on completion to acquire a 40% interest from 1 January 2013;
  - an additional $130 million cash payment is conditional upon a positive final investment decision by Osaka Gas of LNG development or tolling/substituting equity gas through third party LNG infrastructure ($50 million payable on decision and $80 million paid in line with project costs); and

28 PNG oil and gas assets are operated under different licences depending on their advancement: Petroleum Development Licence ("PDL"), Petroleum Retention Licence ("PRL") and Petroleum Prospecting Licence ("PPL").
29 Known as PRL 4 prior to the grant of the PDL on 30 May 2014.
30 Prior to PNG Government 22.5% back-in.
31 Prior to PNG Government 22.5% back-in and the Osaka Gas option.
32 Assuming CNOOC exercises its right to participate up to 51%.
33 Horizon's interest in Whio Prospect area subject to reduction to 10% in the event of a commercial discovery.

- Horizon is entitled to Osaka Gas' share of condensate production (post PNG Government back-in) from the Stanley, Elevala and Ketu fields and part of the Tingu field above a cumulative threshold of 6.7mmbbl[34]. This production adjustment is to be received over the life of the fields, once Osaka Gas has recouped its share of the condensate development costs; and

- the grant to Osaka Gas of an option to acquire 40% of Horizon's interest in PPL 430, PPL 372 and PPL 373 for reimbursement of past costs ("Osaka Gas option").

The PNG Government granted petroleum development licence and a pipeline licence for the Stanley Field on 30 May 2014 triggering the transfer of the balance of the initial sale proceeds plus completion adjustments (totalling approximately $78 million) to Horizon.

Horizon is headquartered in Sydney with a team of around 17 employees. Prior to the announcement of the Merger it had a market capitalisation of around A$480 million.

5.2 Financial Performance

Horizon has generated an operating profit before tax since 2010 reflecting the ramp up of production from the Maari/Manaia oil fields in New Zealand and the Beibu Gulf Joint Venture in China. The financial performance of Horizon for the five and a half years ended 31 December 2013 is summarised below:

Horizon – Financial Performance (US$ millions)						
	Year ended 30 June					Six months ended 31 Dec
	2009 actual	2010 actual	2011 actual	2012 actual	2013 actual	2013 actual
Production (mmbbl)	*0.2*	*0.7*	*0.6*	*0.4*	*0.5*	*0.7*
Average realised oil price[35] ($/bbl)	*51.36*	*71.85*	*98.78*	*116.20*	*108.75*	*105.68*
Development and exploration expenditure ($)	*37.2*	*25.6*	*32.0*	*86.8*	*135.7*	*54.7*
Sales revenue	**8.2**	**48.0**	**59.4**	**50.4**	**48.1**	**64.8**
EBITDAX	**3.6**	**39.6**	**43.1**	**33.2**	**27.3**	**30.0**
Exploration costs written off	(0.9)	(0.2)	(0.3)	(0.3)	(0.6)	(4.2)
EBITDA	**2.6**	**39.4**	**42.8**	**32.9**	**26.7**	**25.8**
Depreciation	-	(0.1)	(0.3)	(0.5)	(0.5)	(0.2)
Amortisation of oil and gas assets	(2.9)	(12.1)	(10.3)	(7.6)	(8.6)	(18.1)
EBIT	**(0.3)**	**27.3**	**32.2**	**24.8**	**17.6**	**7.5**
Finance costs	(2.9)	(3.2)	(2.8)	(6.0)	(8.2)	(8.6)
Interest and other income[36] (net)	(0.1)	-	0.5	(0.2)	(0.4)	0.1
Significant and non-recurring items	-	32.6	18.6	5.0	1.0	2.8
Operating profit before tax	**(3.3)**	**56.7**	**48.5**	**23.7**	**10.0**	**1.8**
Income tax expense	1.3	(4.3)	(13.5)	(16.0)	(6.6)	(1.8)
Profit/(loss) after tax discontinued operations	(6.1)	-	-	-	-	-
NPAT attributable to Horizon shareholders	**(8.1)**	**52.3**	**34.9**	**7.6**	**3.5**	**-**
Statistics						
Basic earnings per share	*(0.24)¢*	*4.64¢*	*3.09¢*	*0.68¢*	*0.31¢*	*-¢*
Sales revenue growth	*nmf*	*nmf*	*23.7%*	*(15.1)%*	*(4.6)%*	
EBITDAX margin	*43.9%*	*82.7%*	*72.5%*	*66.0%*	*56.8%*	*46.2%*
EBITDA margin	*33.0%*	*82.4%*	*72.1%*	*65.4%*	*55.5%*	*39.8%*
EBIT margin	*nmf*	*56.9%*	*54.2%*	*49.4%*	*36.6%*	*11.6%*

Source: Horizon and Grant Samuel analysis

34 Horizon estimated that it would be entitled to an additional 0.9mmbbl of condensate if the 2P reserves and 2C resources defined at the time of the agreement (May 2013) were achieved and a further 3.2mmbbl if prospective resources were achieved (post PNG Government back-in).

35 Before hedging.

36 Interest and other income (net) includes rent received and foreign exchange gains/(losses).

Sales revenue represents oil sales from the Maari/Manaia oil fields (which commenced production in 2009) and the Beibu Gulf Joint Venture (which commenced production in March 2013).

Significant and non-recurring items include:

- in FY10[37] and FY11 the profit on the sale of a 50% interest in PRL 4 (now PDL 10) and PRL 5 (now PRL 21) in PNG to Talisman; and
- the unrealised movement in the value of convertible bond conversion rights since the convertible bonds were issued in June 2011 (see Section 5.3).

Horizon's earnings in the six months to 31 December 2013 were affected by reduced production at the Maari/Manaia oil fields, which were shut in on 21 July 2013 and only restarted on 12 December 2013 after completion of repair works on the floating, production, storage and offloading vessel ("FPSO") Raroa. Horizon expects to recover a proportion of its share of the cost of works ($8 million) and lost profits during field downtime ($5 million) through insurance.

Set out below is an analysis of Horizon's sales revenue and earnings before tax by segment:

Horizon – Financial Performance by Segment (US$ millions)

	Year ended 30 June					Six mths ended 31 Dec
	2009 actual	**2010 actual**	**2011 actual**	**2012 actual**	**2013 actual**	**2013 actual**
Sales revenue						
New Zealand (development)	8.2	48.0	59.4	50.4	31.9	4.2
China	-	-	-	-	16.2	60.6
PNG	-	-	-	-	-	-
Discontinued operations	0.2	-	-	-	-	-
Unallocated	-	-	-	-	-	-
Total sales revenue	**8.4**	**48.0**	**59.4**	**50.4**	**48.1**	**64.8**
Earnings before tax						
New Zealand (development)	2.5	18.6	32.7	26.4	13.5	(13.8)
New Zealand (exploration)	-	-	0.3	-	-	(3.9)
China	-	-	(0.1)	(0.3)	10.9	22.5
PNG	(0.2)	-	(1.6)	(1.5)	(0.4)	(0.4)
Discontinued operations	(6.1)	-	-	-	-	-
Unallocated (net)	(5.5)	5.5	(1.9)	(5.7)	(14.6)	(5.5)
Total earnings before tax	**(9.3)**	**24.1**	**29.4**	**18.9**	**9.4**	**(1.1)**
Reconciliation to operating profit before tax						
Discontinued operations	*6.1*	-	-	-	-	-
Significant and non-recurring items	-	*32.6*	*18.6*	*5.0*	*1.0*	*2.8*
Foreign exchange gains/(losses)	*(0.3)*	*(0.2)*	*0.4*	*(0.3)*	*(0.4)*	*(0.1)*
Interest and rental income	*0.2*	*0.2*	*0.1*	*0.1*	-	*0.2*
Operating profit before tax (as above)	*(3.3)*	*56.7*	*48.5*	*23.7*	*10.0*	*1.8*

Source: Horizon and Grant Samuel analysis

The operating performance of each of Horizon's assets is discussed in Section 5.6 of this report.

Unallocated (net) represents the costs incurred by Horizon that are not recovered from projects including finance costs, unrealised movements in convertible bond conversion rights, foreign exchange gains and losses, head office costs and public company costs.

Outlook

Horizon has not publicly released earnings forecasts for the year ending 30 June 2014 or beyond.

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37 FYXX = financial year end 30 June XX.

5.3 Financial Position

Since 2008 Horizon has invested around $370 million in exploration and development. This investment has been funded by a combination of the proceeds from the issue of shares and convertible bonds, bank loans, the sale of assets and cash from operations. The financial position of Horizon as at 30 June 2013 and 31 December 2013 is summarised below. It should be noted that, although Horizon had a working capital deficit at 31 December 2013, the financial statements were prepared on a going concern basis having regard to the anticipated completion of the Osaka Gas transaction and existing sources of funding:

Horizon – Financial Position ($ millions)		
	As at 30 June 2013 actual	**As at 31 December 2013 actual**
Trade and other receivables	19.8	22.8
Inventories	7.9	6.4
Trade and other payables	(40.3)	(43.1)
Net working capital	**(12.6)**	**(14.0)**
Oil and gas assets (net)	317.6	340.0
Exploration and evaluation expenditure (net)	92.5	112.8
Property, plant and equipment (net)	8.2	8.0
Deferred tax liabilities (net)	(6.6)	(8.0)
Derivative financial instruments (net)	(1.2)	(5.9)
Restoration provision	(15.7)	(26.1)
Osaka Gas transaction deposit	(20.4)	(20.4)
Other payables	(0.9)	(0.7)
Total funds employed	**361.0**	**385.6**
Cash and deposits	19.0	37.1
Bank loans and convertible bonds	(213.0)	(213.6)
Net borrowings	**(194.0)**	**(176.6)**
Net assets attributable to Horizon shareholders	**167.0**	**209.1**
Statistics		
Shares on issue at period end (million)	*1,138.3*	*1,302.6*
Net assets per share	*$0.15*	*$0.16*
Gearing[38]	*53.7%*	*45.8%*

Source: Horizon and Grant Samuel analysis

Oil and gas assets (net) represents Horizon's investment in producing assets (net of accumulated amortisation) (Maari/Manaia Fields, Beibu Gulf Joint Venture) and assets under development (Stanley Project).

Exploration and evaluation expenditure (net) represents the capitalised costs associated with Horizon's exploration and appraisal activities. The carrying value of each exploration and evaluation area is dependent on the successful development and commercial exploitation or sale of the respective areas of interest. At 31 December 2013 the majority of this amount relates to PRL 21 (Elevala/Ketu) in PNG.

Horizon uses derivative financial instruments to manage its exposure to oil price, interest and foreign exchange rate risk (where appropriate). In particular, since entering into a $160 million reserves based debt facility, it has hedged a proportion of its oil production to manage its exposure to oil price volatility. Initially, it hedged 442,000 barrels of Maari production over 24 months to March 2014. At 30 June 2013, 119,000 barrels of Brent oil price swap contracts remained in place. Following commencement of production from the Beibu Gulf fields in March 2013, Horizon executed further hedging covering a further 1,260,000 barrels of Maari and Beibu production over a 24 month period to July 2015 (approximately 40% of forecast production over the period). At 31 December 2013, 1,041,500 barrels of Brent oil price swap contracts and collars were in place, representing a net derivative liability of $5.9 million.

38 Gearing is net borrowings divided by net assets plus net borrowings.

The Osaka Gas transaction deposit represents the conditionally refundable deposit paid by Osaka Gas on execution of the asset sale agreement in May 2013. This liability has been extinguished following the satisfaction of the remaining conditions to the agreement.

Horizon's borrowings comprise both bank facilities and convertible bonds. At 31 December 2013, Horizon had $213.6 million in borrowings as follows:

Horizon – Borrowings at 31 December 2013 (US$ millions)			
Facility	**Amount Committed**	**Amount Drawn**	**Maturity**
Reserves based debt facility			
Amount	160.0	134.3[39]	March 2018
Capitalised borrowing costs	-	(4.6)	
	160.0	**129.7**	
Convertible bonds			
Face value	80.0	80.0	June 2016
Value of conversion rights at issue	-	(20.0)	
Fair value of conversion rights at 31 December 2013	-	14.6	
Other fair value adjustments (net) at 31 December 2013	-	12.7	
	80.0	87.3	
Capitalised borrowing costs	-	(3.4)	
	80.0	**83.9**	
Total	**240.0**	**213.6**	

Source: Horizon and Grant Samuel analysis

The reserves based debt facility is secured, has a six year term and is of an amortising nature (e.g. the facility will reduce to $140 million at 31 December 2014). It bears a floating interest rate of LIBOR plus a margin of up to 3.95%. A change of control of Horizon is a review event (and potentially an event of default) under the debt facility which could lead to early repayment of the facility and/or payment of additional fees to the lenders[40].

Horizon issued 400 convertible bonds for $80 million on 17 June 2011. The bonds carry a coupon of 5.5% per annum, payable semi-annually in arrears and at issue offered a 7% yield to maturity. The bonds mature on 17 June 2016, at which time they will be redeemed at 108.8% of their principal amount (i.e. $87 million), if not previously converted. The bonds are listed on the Singapore Securities Exchange. The convertible bonds are recognised by Horizon at 31 December 2013 at $87.3 million (excluding transaction costs but including fair value adjustments).

The convertible bonds were issued with an initial conversion price of US$0.52 subject to adjustment in certain circumstances. At the date of this report, the adjusted conversion price is US$0.409. On conversion Horizon may elect to settle the bonds in cash or ordinary shares (except in certain situations where the bonds must be settled in cash). Based on the adjusted conversion price the maximum number of Horizon shares that could be issued on conversion is 195,599,022 ordinary shares. At the date of this report no bonds had been converted. A change of control or a delisting of Horizon triggers an adjustment event which results in a reduced conversion price becoming available to bondholders and a right to require redemption of all or some of the holder's bonds for a cash amount. Bondholders can elect to action either of these rights.

The restoration provision represents the best estimate of the present value of Horizon's obligations in relation to the decommissioning and removing of projects assets and restoring the site at the end of economic life. The provision at 31 December 2013 represents Horizon's obligation in relation to the Maari/Manaia oil field and the Beibu Gulf Joint Venture.

At 31 December 2013, Horizon was party to joint venture operations which had commitments for exploration, development and production expenditure totalling $116.6 million ($78.4 million

[39] In addition to cash drawdowns, Horizon has drawn down a letter of credit of $20.4 million for the Osaka Gas transaction deposit.
[40] Horizon has obtained waivers from its lenders in advance of implementation of the Merger to ensure the facility remains on foot.

within 12 months) of which around 60% related to PNG assets. These commitments may be deferred or modified by entering into farm out agreements or working interest trades over time.

At 31 December 2013 Horizon disclosed the following contingent assets and liabilities:

- as completion of the Osaka Gas transaction was conditional on a number of factors, all of the consideration was treated as a contingent asset;
- a proportion of the $8 million in repairs costs at Maari oil field incurred during FY14 is expected to be recovered from insurance; and
- as a party to joint venture agreements, Horizon is exposed to contingent liabilities relating to the need to meet expenditure commitments of a defaulting joint venture party (typically on a proportionate basis).

As all conditions precedent to the completion of the Osaka Gas transaction have now been fulfilled with the grant of the PDL on 30 May 2014, the deposit is no longer refundable and the remainder of the initial payment is now receivable, together with Osaka Gas' share of field costs since 1 January 2013. Consequently, an amount of approximately $78 million is now payable by Osaka Gas to Horizon.

Horizon has no Australian subsidiaries and is not subject to the Australian tax consolidation regime. However, it currently has carried forward Australian income tax losses of A$24.6 million (tax shield A$7.4 million) all of which have been recognised, A$13.5 million of Australian capital losses that have not been recognised and no accumulated Australian franking credits. Horizon expects to generate some income tax losses in New Zealand during FY14 and has the following income tax losses in other jurisdictions which have not been recognised:

Horizon – Non Australian Carried Forward Income Tax Losses (US$ millions)

Jurisdiction	Carried Forward Tax Losses	Applicable Tax Rate	Tax Shield Potential
United States	10.6	34%	3.6
PNG	151.9	45% / 30%[41]	68.4 / 45.6

Source: Horizon

Utilisation of these carried forward losses is subject to a range of factors and there is no certainty as to whether or when they will be recouped. Approximately 40% of the PNG carried forward losses are to be transferred to Osaka Gas upon completion of the Osaka Gas transaction.

5.4 Capital Structure and Ownership

Horizon has 1,301,981,265 fully paid ordinary shares and 1,500,000 ordinary shares partly paid to A$0.01 on issue. There are around 5,700 registered ordinary shareholders in Horizon. The top 20 shareholders account for around 72% of the ordinary shares on issue. Around 43% of registered shareholders hold less than 10,000 shares but this represents less that 1% of the shares on issue. Horizon shareholders are predominantly Australian based investors (around 65-70% of shares on issue). Directors and executives of Horizon are estimated to account for around 2% of the shares on issue. Horizon has received substantial shareholder notices as follows:

Horizon – Substantial Shareholders

Shareholder	Date of Notice	Number of Shares	Percentage
Austral-Asia Energy Pty Limited	2 May 2014	319,695,688	24.55%
Commonwealth Bank of Australia	10 February 2014	137,792,074	10.58%
Tribeca Investment Partners Pty Limited	2 May 2014	68,387,994	5.25%

Source: Horizon

Austral-Asia Energy Pty Limited ("Austral-Asia") is a subsidiary of the privately owned Singaporean headquartered IMC Group and has been a long term private investor in Horizon. One of Horizon's non-executive directors (Mr Gerrit de Nys) is associated with IMC Group.

41 The applicable tax rate differs depending on whether the taxable income against which the PNG losses are recovered is sourced from a petroleum project (45%) or a gas project (30%).

The partly paid ordinary shares are issued on the exercise of employee options. The outstanding obligation in relation to these shares is payable when called or by the date not exceeding five years from the grant of the option which gave rise to the partly paid share. Partly paid shares entitle the holder to participate in dividends and the proceeds on winding up in proportion to the number of shares held and to one vote per share in proportion to the total issue price then paid up. The 1,500,000 partly paid ordinary shares on issue expire on 25 September 2014 and A$0.285 per share is outstanding (total A$427,500).

In addition, Horizon has the following securities over unissued ordinary shares on issue:

- 18,500,000 options issued under the General Option Plan;
- 5,175,000 options issued under the Employee Performance Incentive Plan;
- 6,266,667 options issued under the Employee Option Scheme;
- 31,281,639 share appreciation rights issued under the Long Term Incentive Plan; and
- 400 convertible bonds listed on the Singapore Securities Exchange (refer Section 5.3 above).

The options and share appreciation rights on issue are summarised below:

Horizon – Options and Share Appreciation Rights on Issue

Grant Date	Expiry Date	Exercise Price	On Issue	Vested and Exercisable	Unvested	
					"in the money"	"out of money"
General Option Plan						
11 Dec 2009	11 Dec 2014	A$0.344	500,000	500,000	-	-
6 Jun 2011	30 Jun 2014	A$0.364	15,000,000[42]	15,000,000	-	-
10 Jan 2012	10 Apr 2015	A$0.209	1,000,000	666,667	333,333	-
28 May 2012	27 Aug 2015	A$0.264	2,000,000	1,333,334	666,666	-
			18,500,000	**17,500,001**	**999,999**	**-**
Employee Performance Incentive Plan						
25 Sept 2009	25 Sept 2014	A$0.289	5,175,000	5,175,000	-	-
			5,175,000	**5,175,000**	**-**	**-**
Employee Option Scheme						
25 Sept 2009	25 Sept 2014	A$0.289	350,000	350,000	-	-
9 Oct 2009	9 Oct 2014	A$0.309	2,700,000	2,700,000	-	-
16 Sept 2010	16 Sept 2015	A$0.304	350,000	350,000	-	-
28 May 2012	28 May 2017	A$0.264	1,666,667	1,000,001	666,666	-
17 Sept 2012	17 Sept 2017	A$0.294	500,000	166,667	333,333	-
20 Feb 2013	20 Feb 2018	A$0.434	350,000	-	-	350,000
20 Feb 2013	20 Feb 2018	A$0.404	350,000	-	-	350,000
			6,266,667	**4,566,668**	**999,999**	
Share Appreciation Rights						
1 Oct 2010	1 Oct 2015	-	6,693,828	-	6,693,828	-
5 Aug 2011	5 Aug 2016	-	6,478,276	-	6,478,276	-
13 Aug 2012	13 Aug 2017	-	9,561,936	-	9,561,936	-
19 Aug 2013	19 Aug 2018	-	8,547,599	-	8,547,599	-
			31,281,639	**-**	**31,281,639**	**-**
Total			**61,223,306**	**27,241,669**	**33,281,637**	**700,000**

Source: Horizon

Under the General Option Plan the directors are able to issue options over unissued ordinary shares as considerations in transaction or as compensation to consultants. Each general option on issue is exercisable into one ordinary share, has no dividend entitlement or voting right and lapses on expiry date.

The Employee Performance Incentive Plan operated to provide long term incentives to certain employees and executive directors. This plan was replaced in April 2010 and there are 5,175,000

42 Granted to Petsec America Pty Limited on 6 June 2011 for the acquisition of Petsec Petroleum LLC, which held interests in the assets of the Beibu Gulf Joint Venture.

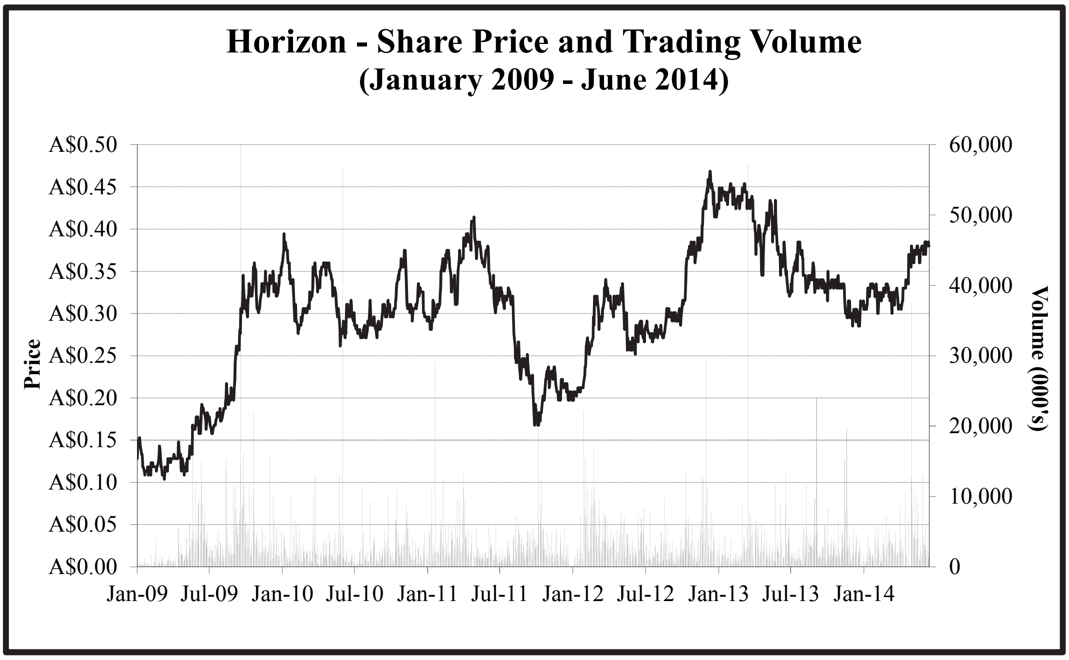
options outstanding under this plan which will expire in September 2014. Each option is exercisable into one ordinary share and has no dividend entitlement or voting right. Options lapse on expiry date and on termination of employment (unless determined otherwise by the board).

The Employee Option Scheme is open to permanent full time or part time employees of Horizon (except executive directors and designated senior executives). Each option on issue under this plan is exercisable into one ordinary share, has no dividend entitlement or voting right and expires five years from the date of grant. Options are progressively exercisable in three equal tranches from dates which are 12, 24 and 36 months after grant date. The exercise price is the greater of the price determined by the directors (not less than the five day VWAP prior to the directors meeting resolving to grant the option) and A$0.20 per option and is subject to adjustment in certain circumstances. Upon exercise, only A$0.01 of the exercise price will be payable by the participant (i.e. the shares are issued as partly paid) with the balance being paid when called or by the date not exceeding five years from the grant of the option. Options lapse on their expiry date and on termination of employment (unless determined otherwise by the board).

Under the Long Term Incentive Plan the board has the discretion to grant share appreciation rights to senior executives as long term incentives which may vest subject (amongst other things) to the level of total shareholder return achieved in the vesting period relative to an appropriate index. A share appreciation right is a right to receive either or both a cash payment or shares in Horizon subject to satisfying certain conditions, including performance conditions. The amount of the cash payment or the number of shares that the participant receives on exercise is based on the excess, if any, of the 10 day VWAP of Horizon shares prior to exercise date over the 10 day VWAP of Horizon shares prior to grant date (or any other day determined by the board at the time of grant). No price is payable by the participant on the exercise of a share appreciation right.

5.5 Share Price Performance

The Horizon share price followed the market higher during the period from 2005 to 2007 (to around A$0.30 on an adjusted basis) and then lower following the commencement of the global economic downturn in late 2007, to close at A$0.13 (adjusted basis) on 31 December 2008. The following graph illustrates the movement in the Horizon share price and trading volumes since January 2009:



Source: IRESS

Note: (1) Share prices on an adjusted basis reflecting rights issues during the period.

(2) On one day in this period more than 60 million shares traded but this is not shown on the graph (18 September 2009 when Horizon's major shareholder, Oasis Energy Investments Pty Limited, sold its 14% interest).

Horizon shares continued to trade below A$0.15 (adjusted basis) until mid 2009 when the price rose steadily following the commencement of production at the Maari/Manaia oil fields in New Zealand. Following the announcement of the sale of a 50% interest in its PNG assets to Talisman and inclusion in the S&P/ASX 300 Index in September 2009, the Horizon share price jumped to above A$0.30 (adjusted basis) (notwithstanding the sell down of its major shareholders' 14% interest). Horizon shares traded broadly in the range of A$0.30-0.40 (adjusted basis) through 2010 before declining to around A$0.20 in the second half of 2011 following the acquisition of interests in the Beibu Gulf Joint Venture which was funded by the issue of convertible bonds and the issue of options over unissued shares.

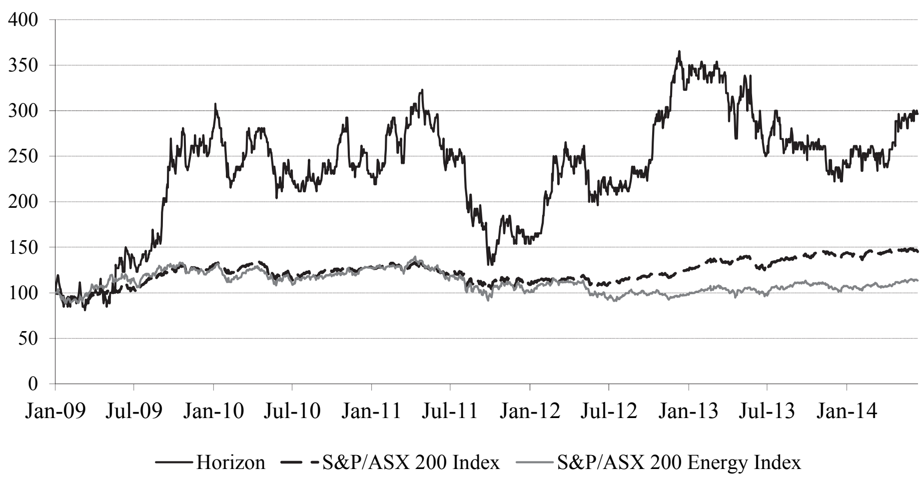
The Horizon share price recovered during 2012 to around A$0.30 to close at A$0.42 (adjusted basis) on 31 December 2012 on the back of positive news from all of its investments. During 2013 Horizon shares traded in the range of A$0.28-0.47 (at a VWAP of A$0.37). During this period the share price was supported by inclusion in the S&P/ASX 200 Index in March 2013, the announcement of the Osaka Gas transaction in May 2013, a fully underwritten rights issue in July 2013 (raised A$53.5 million at a price of A$0.33) and earnings from New Zealand and China.

During 2014, prior to the announcement of the Merger on 29 April 2014, Horizon shares traded in the range A$0.30–0.37 (at a VWAP of A$0.32) and closed at A$0.37 on 23 April 2014 (the last day Horizon shares were traded prior to the announcement). Since then Horizon shares have traded in the range A$0.33-0.39 (at a VWAP of A$0.372) and closed at A$0.38 on 13 June 2014.

Horizon is a reasonably liquid stock. Average weekly volume over the twelve months prior to the announcement of the Merger represented around 1.2% of average shares on issue or annual turnover of 62% of total average issued capital (80% excluding Austral-Asia Energy Pty Limited).

Horizon is a member of various indices including the S&P/ASX 200 Index and the S&P/ASX 200 Energy Index (to which it was admitted in March 2013). It is also a member of the S&P/ASX 300 Index having been admitted in September 2009. Its weighting in the S&P/ASX 200 Index and S&P/ASX 200 Energy Index is approximately 0.03% and 0.51% respectively. The following graph illustrates the performance of Horizon shares since January 2009 relative to these indices:

Horizon vs S&P/ASX 200 Index vs S&P/ASX 200 Energy Index (January 2009 - June 2014)



Source: IRESS

After trading in line with the indices in the first half of 2009, Horizon substantially outperformed for the remainder of 2009. Until mid 2012, while the indices traded broadly in line with each other, Horizon shares experienced relatively long periods of under and over performance. Since then the S&P/ASX Energy Index has generally underperformed the wider market, albeit mirroring movements. In the same period Horizon has either traded in line with or outperformed the market (in particular outperforming during April 2014 prior to the announcement of the Merger).

5.6 Operations

Horizon operations consist of producing assets in New Zealand and China and development and exploration potential in New Zealand, China and PNG as shown below.

Horizon – Asset Location

Source: Horizon

5.6.1 Papua New Guinea

Overview

Horizon's assets in PNG consist of a portfolio of interests in tenements covering an area of 7,900 square kilometres in the liquids rich Foreland Basin of the Western Province of PNG. Upon completion of the Osaka Gas transaction, Horizon's PNG interests will be as follows:

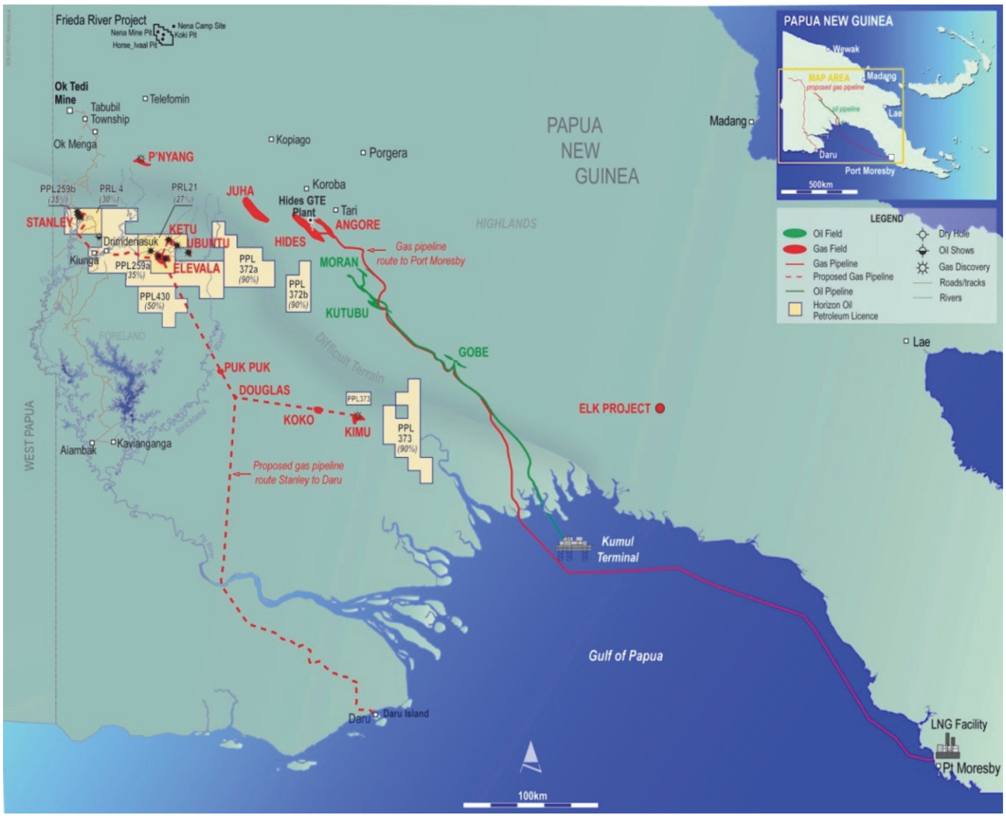
Horizon - PNG Interests

Licence[28]	Field/ Prospect	Horizon Interest	Partners	Operator	Status
PDL 10[29]	Stanley	30%[30]	Osaka Gas (20%), Talisman (40%), Mitsubishi (10%)	Talisman	Development
PRL 21	Elevala[43]/ Ketu	27%[30]	Osaka Gas (18%), Talisman (32.5%), Kina (15%), Mitsubishi (7.5%)	Horizon	Appraisal
PPL 259	Nama	35%[30]	Osaka Gas (10%), Eaglewood (45%), Mega Fortune (10%)	Eaglewood	Exploration
PPL 430	-	50%[31]	Eaglewood (50%)	Horizon	Exploration
PPL 372	-	90%[31]	Jurassic (10%)	Horizon	Exploration
PPL 373	-	90%[31]	Jurassic (10%)	Horizon	Exploration

Source: Horizon

43 Including the Tingu field which is interpreted as being an extension of the Elevala field.

These tenements are close to the town of Kiunga. Existing roads and the nearby Fly River provide relatively good access to local areas and to the coast:



Source: Horizon

The licences are at various stages of exploration and development. Activities to date have been focused on the exploration and development planning of the Stanley gas condensate field in PDL 10 and the exploration of the Elevala and Ketu gas condensate discoveries in PRL 21.

At 1 January 2014, Horizon had an interest in 3.4mmboe of condensate reserves (2P) at Stanley and an additional 77.8mmboe in gas and condensate contingent resources (2C) at Stanley, Elevala and Ketu as follows:

PNG – Horizon Share of Reserves and Resources at 1 January 2014[30]

		Proven + Probable Reserves (2P)			Contingent Resources (2C)		
		Gas (bcf)	Condensate (mmbbl)	Total (mmboe)	Gas (bcf)	Condensate (mmbbl)	Total (mmboe)
PDL 10	Stanley	-	3.4	**3.4**	120	0.4	**20.4**
PRL 21	Elevala	-	-	**-**	186	9.6	**40.5**
PRL 21	Ketu	-	-	**-**	79	3.8	**16.9**
Total		**-**	**3.4**	**3.4**	**385**	**13.8**	**77.8**

Source: Horizon

Current expectations are that condensate stripping from the Stanley wet gas field will commence in 2016 with sales of gas to local customers expected to commence concurrently or shortly thereafter. Condensate production from Elevala and Ketu ("EKT") is expected to commence in 2018. Gas resources from EKT are expected to be aggregated with other regional gas resources to underpin the development of a long life mid-scale LNG project or could be sold to a third party LNG project (e.g. PNG LNG). Condensate and gas production from the Stanley and EKT fields is expected to peak at in excess of 18mmboe per annum (gross) once all the fields are in production.

Stanley Field

The Stanley gas and condensate field was discovered in 1999 following the drilling of the Stanley-1 well. Horizon re-entered and tested the well in 2008 and undertook further appraisal at the tenement including 2D seismic and the drilling of Stanley-2 and Stanley-4 appraisal wells. A FEED study completed in 2012 led to a final investment decision in July 2012.

It is proposed that wet gas will be extracted through two production wells and treated at the Stanley Gas Plant to recover the condensate. Condensate will then be piped through a 40 kilometre pipeline to Kiunga where it will be stored in a 60,000bbl storage tank. The condensate will be shipped in a 33,000bbl tanker down the Fly River and across the Gulf of Papua to the Napa Napa refinery in Port Moresby. The condensate is a light crude product and is expected to be sold at a small discount to Brent. The dry gas will be sold to local customers to be used for power generation. Any gas not sold at the time of extraction will be reinjected into the reservoir through two dry gas injection wells to provide pressure support.

Customers for gas from the Stanley Field have yet to be finalised. Both the Ok Tedi copper-gold mine and the pre-development Frieda River copper project would benefit from gas fired power generation. The combined needs of Ok Tedi and Frieda River would account for the total gas produced from the Stanley Field. There is also potentially an opportunity to provide gas to local communities or to export gas to the province of West Papua in Indonesia to be used for power generation.

The Ok Tedi mine, controlled by the State of Papua New Guinea, is located approximately 100 kilometres north of the Stanley Field. Power requirements are currently met by a small scale hydroelectric plant supplemented by a diesel power plant when water flows are not sufficient. As part of a potential 20 year mine life extension, Ok Tedi is exploring alternative power sources and has held discussions with Horizon regarding potential gas supply from Stanley.

Frieda River is a very large scale, long life copper-gold project located approximately 80 kilometres northwest of Ok Tedi. The mine would require 10-15PJ of power per annum. Various options are being assessed for its power supply, including gas fired generation fuelled by gas from the Stanley field. The project has not yet been sanctioned for development and first gas sales would not likely occur before the end of the decade.

Horizon (as operator) applied for a petroleum development licence and a pipeline licence for the Stanley gas condensate project in August 2012. Approval for the development was received on 14 April 2014 and PDL 10 and PL 10 were granted on 30 May 2014. The licensees and the PNG Government have entered into the Stanley Gas Agreement which sets out the fiscal and other terms under which the project will operate. Prior to the award of the PDL, Talisman elected to resume operatorship of the Stanley Field.

Early works have been completed. The project still requires the drilling of two development wells, construction of the production facilities, storage tank, loading facility and associated infrastructure, and laying of the pipeline. Horizon expects first condensate and gas production in mid-2016. Total pre-production expenditure has been estimated at $340 million, of which approximately $40 million had been spent to 31 December 2013.

Condensate production is expected to reach approximately 1.3mmbbl per annum (100%) in 2017 and decline after that. Gas production is expected to plateau at approximately 18PJ per annum for around 15 years. Current reserves and resources support a field life of 25 years. The information collected during the exploration and appraisal programme suggests that there is little prospect of significant exploration upside at the Stanley Field.

EKT Fields

The Elevala and Ketu fields were discovered in 1990 and 1991 and successfully appraised in 2011 and 2012 respectively. The Tingu field, which is interpreted to be an extension of the Elevala field, was discovered in late 2013 and has the potential to be similar in size to the Elevala field with a gas and condensate resource potential of up to 100mmboe. Tingu has been added to the scope of the current FEED study for the development of the Elevala and Ketu fields.

These fields are expected to be developed using a development concept similar to that of the Stanley Field. However, Horizon expects that, rather than being sold to local customers, the gas will be aggregated with other local gas sources to form a combined reserve base of 2-4Tcf sufficient to underpin a 2-4mtpa LNG project. Current studies are based on the following development scenario:

- extraction of the wet gas through two production wells and two reinjection wells at the Elevala field and one production well and one reinjection well at the Ketu field;
- stripping and processing of the condensate at a central processing facility at Elevala;
- transport of condensate via pipeline to Kiunga to be loaded onto barges and shipped down the Fly River to a suitable aggregation facility;
- piping of the gas to a suitable location on the southern coast. Gas from other local fields can be piped via the same pipeline; and
- liquefaction of the gas on a barge-mounted LNG plant moored at a suitable location on the southern coast.

Condensate production is expected to reach approximately 3.3mmbbl (100%) in the first year of production and decline after that. Gas production would commence a few years after condensate production and peak at approximately 55PJ and decline thereafter. The project is expected to have a 20 year field life based on currently delineated resources at Elevala and Ketu and an estimate of likely production from Tingu.

There is support for an LNG project among the joint venture partners. Talisman farmed into the tenements in 2009 with the objective of aggregating sufficient gas resources in the Western Province to underpin a mid-scale LNG project and has interests in other gas fields in the region (e.g. Kimu, Douglas, Puk Puk). Talisman formed a strategic relationship with Mitsubishi Corporation (a major LNG off taker) in 2012 and Horizon sold 40% of its PNG assets to Osaka Gas (one of Japan's leading utility companies and LNG importers) in 2013. LNG not delivered to the joint venture participants could be exported to the Singapore LNG and products hub or to North Asian markets. Should a standalone LNG project not be pursued, the gas could be sold to a third party LNG project.

A FEED study for the condensate stripping component of an EKT development is currently being undertaken and is expected to lead to a final investment decision in 2014. Horizon (as operator) lodged an application for a petroleum development licence in March 2014 and expects to lodge an environmental impact statement during June 2014.

Horizon expects that early works will commence shortly after a final investment decision has been made. Drilling of an additional well at Tingu, construction of the processing plant and laying of pipelines is expected to take two years and lead to first condensate production in 2018. Pre-production costs have been estimated at $1,100 million.

The Tingu discovery is yet to be fully appraised, and as a result the joint venture participants are not yet in a position to announce resources for the proposal. There is potential to integrate into a Stanley/EKT development the nearby Ubuntu field, which is held by Horizon's joint venture partner Eaglewood Energy Inc., Talisman, Mitsubishi Corporation and Mega Fortune International Limited.

Other PNG Assets

Two prospects (Elevala Toro and Tingu Toro) have been identified in the Toro reservoir which underlies the sandstone reservoir which hosts the Elevala/Tingu field. Although these prospects are yet to be flow tested, sufficient data is available to estimate prospective resources.

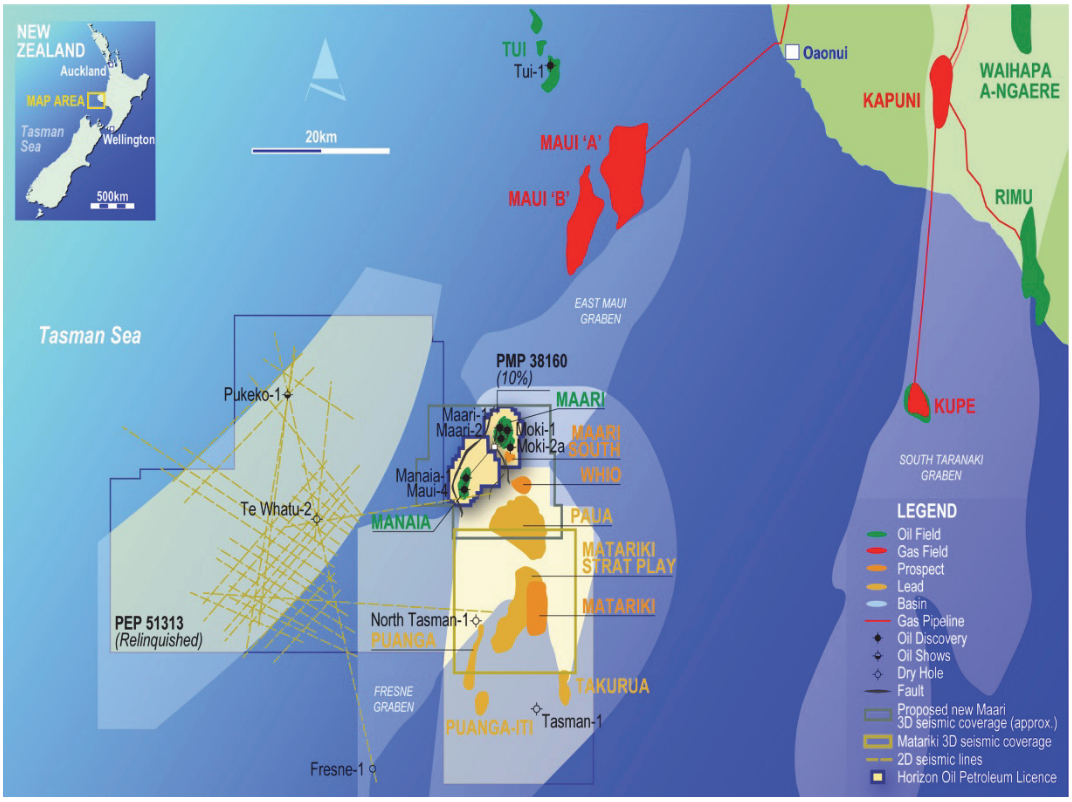
Horizon has an interest in four petroleum prospecting licences, PPLs 259, 430, 372 and 373 and is the operator of all except PPL 259. PPLs 259, 430 and 372 are adjacent to the PDL 10 and PRL 21 licences. PPL 373, which was acquired as part of the acquisition of PPL 372, is located approximately 200 kilometres southeast of the other PPLs but relatively close to acreage in which Talisman has an interest.

Little work has been undertaken at these licences and no reserves or resources have been defined. Seismic data has been acquired at PPL 259 and is currently being interpreted to determine the location of an exploration well to be drilled in late 2014 at the Nama Prospect, which is located close to the Stanley Field. Horizon believes that Nama has the potential to host a resource similar in size to Stanley. Seismic data is expected to be acquired at the other licences during 2014.

5.6.2 New Zealand

PMP 38160 (Maari/Manaia)

Maari and Manaia are producing oil fields located in the Tasman Sea, 80 kilometres off the south Taranaki coast of New Zealand in approximately 100 metres of water:



Source: Horizon

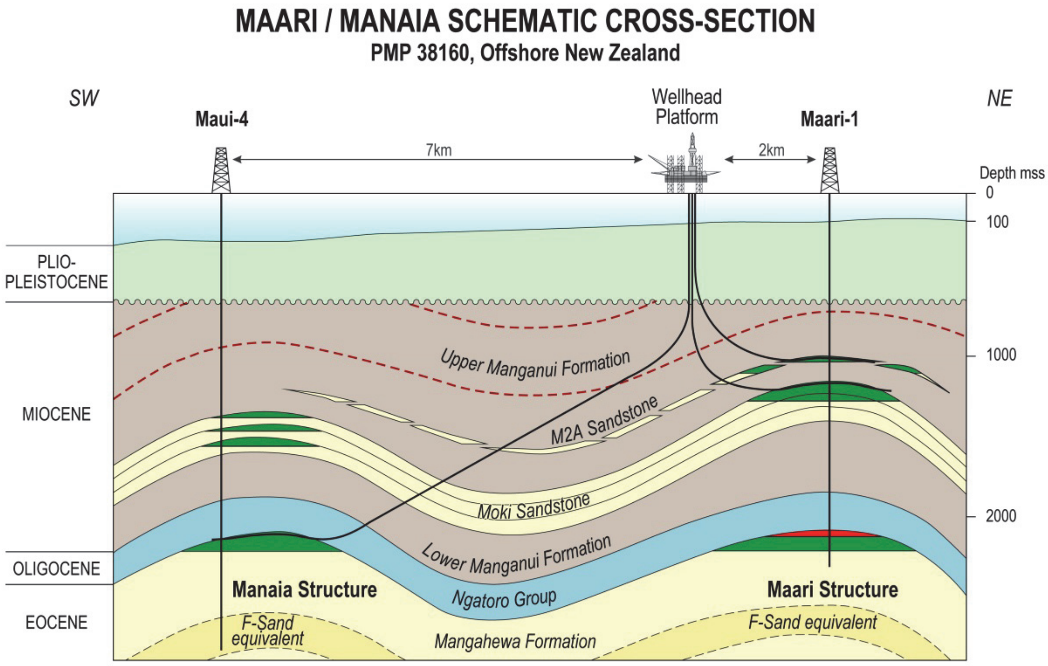
These oil fields are held under petroleum mining permit PMP 38160 via a joint venture structure. The joint venture comprises OMV Group ("OMV") (69% and operator), Todd Exploration Limited (16%), Horizon (10%) and Cue Energy Resources Ltd (5%).

The reserves of PMP 38160 were provisionally downgraded in December 2013 as a result of disappointing field performance under water injection. Reserves at 1 January 2014 were as follows (there are no contingent resources):

PMP 38160 – Reserves at 1 January 2014 (mmboe)		
	Proved (1P)	**Proved + Probable (2P)**
Developed	1.7	2.1
Undeveloped	1.7	4.0
Total	**3.3**	**6.0**

Source: Horizon

Production from PMP 38160 commenced in March 2009 with total cumulative production through 31 December 2013 of 22.4mmbbls. The Maari field currently produces from the Moki and M2A sands with additional oil located in the deeper Mangahewa formation. Production is also sourced from the Mangahewa formation of the Manaia field:



Source: Horizon

The infrastructure associated with PMP 38160 includes a wellhead platform, a floating, production, storage and offloading ("FPSO") vessel, seven production and three water injector wells and associated sub-sea flow lines. Crude oil is delivered from the FPSO to shuttle tankers which transport the product to purchasers' refineries in Australia and South East Asia. Due to the quality of the crude oil produced, PMP 38160 receives a $5-6/bbl premium to the Brent crude oil price.

In March 2013 (following exercise of a right to purchase), the joint venture acquired the previously leased FPSO Raroa to enable greater flexibility and control of the vessel and to facilitate tie-ins of new reservoirs. In July 2013 production was halted as a result of necessary upgrade and repair work to FPSO Raroa. The total cost of the works was approximately $80 million, some of which is expected to be recovered under insurance claims. Production re-commenced in December 2013.

Production at the oil fields has been in decline, in part through the disappointing results of the water injection scheme. As part of the Maari Growth Projects (discussed below) it is proposed to reconfigure the water injection scheme to enhance pressure support and increase production.

Horizon's share of production, sales and earnings before tax from PMP 38160 for the last five and a half years is summarised below:

PMP 38160 – Horizon's Share of Operating Performance (US$ millions)						
	Year ended 30 June					Six mths ended
	2009 actual	2010 actual	2011 actual	2012 actual	2013 actual	31 Dec 2013 actual
Production (mmbbl)	*0.2*	*0.7*	*0.6*	*0.4*	*0.3*	-[44]
Sales revenue	8.2	48.0	59.4	50.2	31.9	4.2
Earnings before tax	2.5	18.6	32.7	26.4	13.5	(13.8)

Source: Horizon (refer Section 5.2)

The Maari Growth Projects obtained Final Investment Decision during 2013. The projects aim to reverse the decline in production rates and to extend the Maari field life beyond 2023. The projects will focus on the following:

- new field development of the Maari Mangahewa formation oil leg (Maari Deep Oil Project);
- further development of the Manaia Mangahewa formation reservoir (Manaia Full Field Development Project);
- optimisation of the current water flood in the Moki Sandstone reservoirs; and
- reclamation and sidetracking of existing Maari wells as oil producer wells to target the Moki sandstone at Maari and the Moki sandstone on the northern flank of Maari.

The Maari Growth Projects are expected to cost NZ$354 million, the majority of which will be spent on drilling costs (NZ$294 million) during in 2014.

PEP 51313 (Matariki)

PEP 51313 is an exploration block located to the south east of PMP 38610. This exploration permit is owned by OMV (30% and operator), Todd Exploration Limited (35%), Horizon (21%) and Cue Energy Resources Ltd (14%).

The Whio Prospect located in the north of the permit is to be the first target drilled in PEP 51313 and, given its close proximity to the Maari field (7 kilometres) and the potential to tie in to the Maari facilities, it has been decided to harmonise the interests in PEP 51313 and PMP 38160. Consequently, OMV is to fund the cost of the exploration well targeting the Whio Prospect. If the exploration proves a commercial discovery, OMV's share in the Whio Prospect area will increase to 69% and the equity interests in the Whio Prospect will match that of PMP 38160 (i.e. Horizon's interest will be 10%). Drilling of the exploration well is expected to commence in mid 2014.

5.6.3 China

Beibu Gulf Joint Venture

The Beibu Gulf Joint Venture comprises Horizon (55%), ROC (40%) and Majuko Corporation (5%). The joint venture holds Block 22/12 under a petroleum contract originally entered into by Horizon with CNOOC in December 1999 under which CNOOC has a right to participate in up to 51% of any development. CNOOC has exercised this right in relation to the development of the WZ 6-12 and WZ 12-8 West Oil Fields. Consequently, Horizon's interest in the WZ 6-12 and WZ 12-8 West Oil Fields is 26.95%, although it retains its 55% interest in the remainder of Block 22/12. More information on the Beibu Gulf Joint Venture is set out in Section 4.6.5.

[44] Horizon's share 35,895bbl. Production was low during the period as the facilities were shut in to effect repairs on FPSO Raroa.

6 Profile of New ROC

6.1 Operations

New ROC will be one of the largest Asian focused upstream oil and gas companies listed in the ASX. It will own a portfolio of assets across the spectrum of upstream activities with 2P reserves of 33.3mmboe and 2C resources of 113.0mmboe as summarised below:

New ROC – Portfolio of Oil and Gas Assets

Location/ Asset	Interest	Status	As at 1 January 2014 2P Reserves (mmboe)	As at 1 January 2014 2C Resources (mmboe)
China				
Zhao Dong Joint Venture	C/D Fields: 24.5% C4 Field: 11.667% Zhanghai/Chenghai: 39.2%	Production/ Development	3.7	4.6
Block 09/05	100.0%	Exploration	-	-
Beibu Gulf Joint Venture	46.55% 95.0%	Production/ Development Exploration/Appraisal	11.2 -	- 2.6[32]
Papua New Guinea				
PDL 10 (Stanley)	30.0%[30]	Development	3.4	20.4
PRL 21 (Elevala/Ketu)	27.0%[30]	Appraisal	-	57.4
PPL 259	35.0%[30]	Exploration	-	-
PPL 430	50.0%[31]	Exploration	-	-
PPL 372	90.0%[31]	Exploration	-	-
PPL 373	90.0%[31]	Exploration	-	-
Malaysia				
D35/D21/J4 PSC	30.0%[10]	Production/Development	5.2	23.9
Balai Cluster RSC	48.0%[45]	Development	-	-
Myanmar				
Block M07	59.375%[11]	Exploration	-	-
New Zealand				
PMP 38160 (Maari/Manaia)	10.0%	Production/Development Exploration/Appraisal	6.0	-
PEP 51313 (Matariki)	21.0%[33]	Exploration	-	-
Australia				
Cliff Head	42.5%	Production	2.2	2.3
L14 (Jingemia)	0.25%	Production	nmf	nmf
United Kingdom				
Blane	12.5%	Production	1.3	0.7
Enoch/J1	12.0%	Production	0.3	1.1
Total			**33.3**	**113.0**

Source: ROC and Horizon

Approximately 96% of New ROC's 2P reserves are liquids while, due to Horizon's substantial gas resources in PNG, New ROC's 2P + 2C position is broadly 50/50 liquids and gas.

No decision has been made in relation to the company name. However, it is intended that the "Roc Oil" brand will be used in the conduct of New ROC's business in China and South East Asia while the "Horizon Oil" brand will be used in PNG and New Zealand.

6.2 Directors and Management

New ROC's board will consist of a minimum of eight directors including three current non-executive directors from ROC, four current non-executive directors of Horizon and one current executive director from Horizon. The current Chairman of ROC (Mike Harding) will be Chairman of New ROC and the current CEO of Horizon (Brent Emmett) will be CEO of New ROC. The senior management team will be drawn from the existing management teams of ROC and Horizon, with the current CEO of ROC (Alan Linn) continuing in an executive role until April 2015.

45 Held via a 48% interest in BC Petroleum.

6.3 Earnings and Dividends

Given the number of events which have impacted the financial performance of ROC and Horizon in the year ended 31 December 2013, the directors of ROC and Horizon have decided not to prepare pro forma financial performance in relation to the Merger (on the basis that it would not be a true reflection of the New ROC).

Furthermore, no pro forma forecast financial performance information has been prepared for New ROC. However, pro forma production for the year ending 31 December 2014 is projected to be 5.5mmboe (primarily oil from the Chinese assets) and corporate overhead cost savings in the order of $4-5 million are anticipated. The Merger is not expected to have any tax consequences for ROC or its existing shareholders.

Neither ROC nor Horizon currently pays dividends. Following the proposed refinancing, New ROC may look to pay dividends. However, the payment of dividends is a matter for the board of New ROC having regard to, amongst other things, available profits, its financial position and capital requirements.

6.4 Financial Position

The pro forma financial position of New ROC as at 31 December 2013 has been prepared by Horizon for inclusion in the Scheme Booklet to be sent to its shareholders in relation to the Merger and is summarised below:

New ROC – Pro Forma Financial Position (US$ millions)

	As at 31 December 2013 pro forma
Trade and other receivables	57.9
Inventories	9.2
Trade, other payables and employee provisions	(101.9)
Net working capital	**(34.8)**
Oil and gas assets (net)	582.7
Property, plant and equipment (net)	8.8
Exploration and evaluation expenditure	79.5
Investment in BC Petroleum (48%)	67.2
Derivative financial instruments (net)	(5.9)
Deferred tax liabilities (net)	(25.3)
Employee provisions (non current)	(48.7)
Restoration provision	(20.1)
Total funds employed	**603.4**
Cash and deposits	64.8
Borrowings	(114.6)
Net Borrowings	**(49.8)**
Net assets attributable to New ROC shareholders	**553.6**
Statistics	
Shares on issue at period end (million)	1,640.2
Net assets per share	$0.34
Gearing	8.2%

Source: ROC, Horizon and Grant Samuel analysis

The pro forma financial position has been prepared by Horizon on the basis that the Merger was implemented on 31 December 2013. Specifically, it:

- is prepared under the "reverse acquisition accounting" method as it has been determined that Horizon is the acquirer for accounting purposes (notwithstanding that the Merger is a "merger of equals"). This method means that the net assets of ROC are restated at fair value while Horizon's net assets are maintained at historical book value. The pro forma financial position reflects a provisional position on fair values subject to finalisation following implementation of the Merger;

- reflects the accounting policies of Horizon;
- reflects adjustments for a number of material transactions that have occurred post 31 December 2013 (e.g. the sale of the 50% interest in the BMG Project, the 30% farm in to the D35/D21/J4 PSC, $15.7 million repayment of debt facility by Horizon, completion of the Osaka Gas transaction);
- recognises all aspects of the Merger including:
  - the acquisition of Horizon (after the exercise of all vested and exercisable options and the creation of a receivable from the optionholders) by the issue of 952,583,404 ordinary shares to former Horizon shareholders and optionholders; and
  - allowance for a premium on redemption of Horizon's convertible bonds; and
- recognises pro forma adjustments (including fair value adjustments, elimination of intercompany balances) and recognises transactions costs associated with the Merger.

A detailed pro forma position (including a description of the assumptions and adjustments made) will be set out in Section 12.6 of the Horizon Scheme Booklet. The pro forma financial position has been prepared by Horizon and reviewed by an investigating accountant.

The pro forma financial position shows that New ROC will have net borrowings of approximately $50 million and gearing of 8.2%.

6.5 Capital Structure and Ownership

Following implementation of the Merger, New ROC will have the following securities on issue:

- 1,640,201,804[46]; ordinary shares
- 2,818,726[47] options over unissued ordinary shares;
- 46,960,184[48] LTI Rights; and
- 1,886,476[49] STI Rights.

On this basis, former ROC shareholders will collectively hold 41.9% of New ROC ordinary shares (including partly paid shares) and former Horizon shareholders will collectively hold approximately 58.1%. The major shareholders in New ROC are expected to be as follows:

New ROC – Major Shareholders		
Shareholder	**Number of Shares**	**Percentage[50]**
Austral-Asia	231,459,678	14.11%
Allan Gray	137,906,663	8.41%
Commonwealth Bank of Australia	99,761,461	6.08%
Tribeca Investment Partners Pty Limited	49,512,907	3.02%

Source: Grant Samuel analysis

46 Includes the conversion of 1,500,000 Horizon partly paid shares and the exercise of 12,241,668 vested Horizon options upon implementation of the Scheme. Excludes 15,000,000 vested Horizon options held by Petsec America Pty Limited which expire on 30 June 2014 (if these options are exercised a further 10,680,000 New ROC shares will be issued) and any Horizon shares that may be issued upon conversion of convertible bonds prior to the record date for the scheme.

47 Excludes unvested "out of the money" Horizon options which may be cancelled via a cash out option. In the event that these options are retained, up to an additional 635,513 options over unissued New ROC shares could be granted.

48 Excluding 1,180,841 LTI Rights approved at the ROC annual general meeting on 27 May 2014 but not yet granted.

49 Excluding 387,209 STI Rights approved at the ROC annual general meeting on 27 May 2014 but not yet granted.

50 Calculated based on 1,640,201,804 ordinary shares.

7 Valuation Analysis

7.1 Valuation Methodology

Grant Samuel's valuations of ROC and Horizon have been estimated by aggregating the estimated market value of each company's interests in oil and gas assets and their exploration interests and adjusting for net cash or net borrowings and other assets and liabilities. The values for the oil and gas interests have been estimated on the basis of fair market value as a going concern, defined as the maximum price that could be realised in an open market over a reasonable period of time assuming that potential buyers have full information. Other assets have been valued on the basis of net realisable value.

The valuations represent Grant Samuel's assessment of the full underlying value of ROC and Horizon respectively. They are appropriate for the acquisition of each company as a whole and, accordingly, incorporate a premium for control. The values are in excess of the level at which, under current market conditions, shares in ROC or Horizon could be expected to trade on the sharemarket. Shares in a listed company normally trade at a discount of 15-25% to the underlying value of the company as a whole (but this discount does not always apply).

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

- capitalisation of earnings or cash flows;
- discounting of projected cash flows;
- industry rules of thumb; and
- estimation of the aggregate proceeds from an orderly realisation of assets.

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

The primary approach to the valuation of ROC and Horizon's oil and gas assets has involved the application of the discounted cash flow ("DCF") methodology. This methodology involves calculating the net present value ("NPV") of projected cash flows. The cash flows are discounted to a present value using discount rates which reflect the risk associated with the cash flow stream. The DCF methodology is particularly appropriate for assets such as oil and gas projects where reserves are depleted over time and significant capital expenditure is required. By contrast, capitalisation of earnings or cash flows is the most commonly used method for valuation of industrial businesses. This methodology is most appropriate for industrial businesses with a substantial operating history and a consistent earnings trend that is sufficiently stable to be indicative of ongoing earnings potential. This methodology is not particularly suitable for start-up businesses, businesses with an erratic earnings pattern or businesses that have unusual capital expenditure requirements.

Cash flow models for each of the oil and gas assets have been developed by Grant Samuel having regard to operating models prepared by ROC and Horizon respectively. The cash flow models are based on operating scenarios developed by RISC which were based on field development and production plans provided by ROC and Horizon. RISC reviewed the technical assumptions in ROC and Horizon's operating models, including those regarding reserve estimates, production profiles, operating costs, capital costs and the potential for reserve extensions, and made adjustments where appropriate. RISC's report is attached as Appendix 2 to this report. Grant Samuel determined the economic and financial assumptions used in the cash flow models. The NPVs have been calculated on an ungeared after tax basis as at 1 January 2014.

Alternative valuation methodologies have been considered as secondary evidence of value, where appropriate. In particular, the value estimates for ROC and Horizon's assets have been reviewed in terms of multiples of reserves and resources, which are metrics commonly used in the oil and gas sector. These metrics, while relatively crude, are useful in assessing the reasonableness of values as DCF valuations are typically sensitive to the assumptions adopted.

The valuations of the oil and gas assets represent Grant Samuel's overall judgement as to value. They do not rely on any one particular scenario or set of economic assumptions. The valuations have been determined having regard to the sensitivity of the DCF analysis to a range of technical and economic assumptions. They incorporate Grant Samuel's assessment of the impact on value of development status and optionality, to the extent not reflected in the DCF analysis.

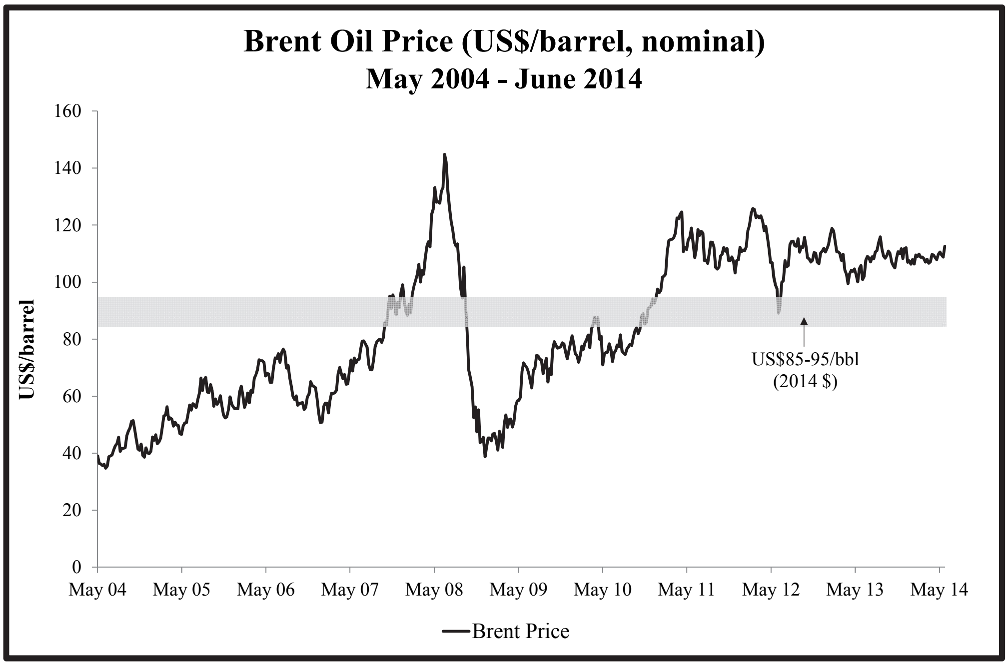
The valuations are based on a number of important assumptions (in particular assumptions regarding future oil and gas prices) and reflect the technical judgements of RISC regarding the prospects for the assets. Oil and gas prices and expectations regarding future operating parameters can change significantly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

7.2 Key Assumptions

There are a number of economic and financial assumptions which apply across the valuation of ROC and Horizon's oil and gas assets:

- **Oil Prices**

  Grant Samuel has assumed that Brent oil prices (in real terms) decrease from the spot prices prevailing in early June 2014 ($105/bbl) to a range of $85-95/bbl from 2018 and are flat thereafter. The long term assumption compared to historical Brent prices (in nominal terms) is shown below:



Source: Bloomberg
Note: Historical prices are in nominal terms while Grant Samuel price assumption is in 2014 dollars.

Grant Samuel's Brent crude oil price assumption is broadly consistent with the range of forecasts used by market analysts. However, assumptions regarding future oil prices are subject to considerable uncertainty as market evidence falls within a very wide range:

- the Brent oil price has been fairly volatile, with trading in a range of $100-125/bbl in the last three years and $105-115/bbl in the last 12 months;
- although some forecasts of Brent oil prices by industry analysts, commentators and corporate participants fall within a relatively narrow range of $85-95/bbl (from 2018, real terms), there are widely varying views with some participants forecasting much lower or higher prices than the range selected by Grant Samuel; and
- the Intercontinental Exchange Brent Futures Contract curve in late May 2014 slopes down to approximately $93/bbl by June 2020, which corresponds to approximately $80/bbl in real terms[51]. Although prices of futures contracts are not necessarily directly correlated to forecast spot prices, they are used by some market participants for their investment decisions.

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

- **Inflation**

  Grant Samuel has assumed United States inflation of 2.5% per annum.

- **Tax Depreciation**

  Tax depreciation schedules determined on the basis of tax written down values for various asset categories. Accumulated carry forward expenditures deductible for tax purposes have been allowed for in the financial models.

- **Discount Rates**

  Nominal discount rates in the range 9.5-10.5%. These rates represent estimates of the costs of capital for investors in upstream oil and gas projects. The rates are estimates of weighted average costs of capital and have been applied to expected future ungeared after tax cash flows. The basis for the selection of the rates is set out in Appendix 3.

Other operational and specific assumptions used in the DCF models in this report are set out in the relevant valuation sections.

51 Sourced from Bloomberg and assuming United States inflation of 2.5% per annum.

7.3 Valuation of ROC

7.3.1 Summary

ROC has been valued in the range US$391-507 million. The valuation represents the estimated full underlying value of ROC assuming 100% of the company was available to be acquired and includes a premium for control. The valuation is summarised below:

ROC - Valuation Summary (US$ million)			
	Report Section Reference	Value Range	
		Low	High
Beibu Gulf Joint Venture	7.3.2	176	196
Zhao Dong Joint Venture	7.3.3	95	105
D35/D21/J4 PSC	7.3.4	12	27
Other producing assets	7.3.5	30	45
Exploration	7.3.6	16	62
BC Petroleum	7.3.7	65	70
Other assets and liabilities	7.3.8	-	-
Corporate costs (net of savings)	7.3.9	(60)	(55)
Enterprise value		**334**	**450**
Adjusted cash	7.3.10	66	66
LTI Rights and STI Rights	7.3.11	(9)	(9)
Value of equity		**391**	**507**

Grant Samuel's valuation reflects evidence as to value from DCF analysis, comparable company analysis and valuation benchmarks commonly used in the oil and gas sector. It is based on a number of assumptions (including assumptions regarding oil prices and future operational performance) which can change significantly over short periods of time. Such changes can have significant impacts on underlying value.

Grant Samuel appointed RISC as technical specialist to review ROC's oil and gas assets. RISC's role included a review of reserves and resources, development plans, production schedules, operating costs, capital costs and exploration potential. RISC prepared valuations of ROC's exploration interests. RISC's report is attached as Appendix 2 to this Report.

Grant Samuel's financial analysis for the oil and gas assets was based on valuation scenarios prepared in conjunction with RISC, reflecting RISC's judgements regarding the range of assumptions as to ultimate oil and gas reserves and resources, project life, production rates, operating costs and capital costs that could reasonably be adopted for valuation purposes. Grant Samuel determined the financial assumptions used in the analysis. The financial models for ROC's assets projected nominal US$ cash flows from 1 January 2014. Present values were estimated using a range of discount rates.

Grant Samuel's valuation of ROC implies the following valuation parameters:

ROC – Implied Valuation Parameters			
Multiples of	**Variable**	**Implied Multiples[52]**	
		Low	**High**
Value Range (US$ million)			
- Equity value		**391**	**507**
- Equity value (excluding BC Petroleum)		**326**	**437**
- Enterprise value		**334**	**450**
- Enterprise value (excluding BC Petroleum)		**269**	**380**
	(mmboe)		
Reserves and resources (1 January 2014)			
1P (proven)	12.8	$21.03	$29.70
2P (proven and probable)	17.4	$15.47	$21.85
2C (contingent resources)	33.7	$7.99	$11.28
2P + 2C	51.1	$5.27	$7.44
Production			
Year ended 31 December 2013 (actual)	2.7[53]	$95.07[54]	$130.63[54]
Year ending 31 December 2014 (projected)	3.2[55]	$84.13	$118.81
	(US$ million)		
Financial Performance for year ended 31 December 2013			
EBITDAX	152.5	1.8	2.5
EBITDA	136.0	2.0	2.8
EBIT	64.8	4.2	5.9
NPAT (as reported)	45.2	7.2	9.7

The multiples of reserves, resources and production implied by the valuation are considered reasonable (albeit high) relative to market evidence (see Appendix 4) reflecting the significant proportion of ROC's value that is attributable to mature assets with relatively low capital expenditure commitments. The multiples of historical earnings are modest and appropriate for a company with mature producing assets.

7.3.2 Beibu Gulf Joint Venture

Grant Samuel has valued 100% of the Beibu Gulf Joint Venture in the range $900-1,000 million. This implies a value for ROC's 19.6% interest[56] of $176-196 million.

Two scenarios were developed for the valuation of the Beibu Gulf Joint Venture:

- **Scenario 1:** assumes the production of 2P reserves for the WZ 6-12 and WZ 12-8 West Oil Fields which commenced production in March 2013. Production peaks in 2014 at 4.4mmbbl and continues until 2027 (though there is minor tail production beyond this date). As these fields are already developed, only minor capital expenditure for upgrade works ($6 million, 2014 $). Abandonment costs of $41 million (2014 $) are assumed and, in accordance with normal practice in China, are paid across the life of the project. Operating costs (excluding abandonment costs) are initially around $50 million per annum (2014 $) and decline to average $40 million from 2017; and

52 Calculated by reference to enterprise value and equity value excluding the value attributed to ROC's 48% interest in BC Petroleum. BC Petroleum is operator of the Balai Cluster project under a risk service contract and has no interest in the underlying reserves and resources nor did it contribute any earnings in 2013.

53 Including production from the Beibu Gulf Joint Venture only from March 2013.

54 Calculated by reference to enterprise value excluding the value attributed to ROC's 48% interest in BC Petroleum (no interest in reserves and resources) and to D35/D21/J4 PSC (which was not owned in 2013).

55 Including production from D35/D21/J4 PSC from 1 April 2014.

56 Assuming that CNOOC exercises its right to participate to 51% in the WZ 12-8 East Field development and assume operatorship (i.e. ROC's interest in this development would decline from 40% to 19.6%).

- **Scenario 2**: is based on Scenario 1 but also assumes (based on RISC's development plan) the production of 2C resources from the WZ 12-8 East Field. Development capital expenditure for WZ 12-8 East totals $213 million (2014 $) with the majority incurred in 2017 for the drilling of development wells. Production from WZ 12-8 East is assumed to start in 2018 and totals 7.3mmbbl over eight years. Operating costs increase substantially in this scenario as a result of high water content in the later years of production for WZ 12-8 East. Consequently, production becomes uneconomic from 2026. Incremental abandonment costs for WZ 12-8 East of $38 million (2014 $) are paid over the life of the project.

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

Beibu Gulf Joint Venture (100%) – Model Parameters						
	Year end 31 December					Life of Project
	2014	2015	2016	2017	2018	
Scenario 1						
Oil production (mmbbl)	4.4	3.8	2.9	2.4	2.1	**23.9**
Operating costs ($million, 2014 $))	52.6	57.4	52.3	37.9	34.4	**531.1**
Capital expenditure ($million, 2014 $)	-	-	6.0	-	-	**6.0**
Scenario 2						
Oil production (mmbbl)	4.4	3.8	2.9	2.4	5.2	**31.2**
Operating costs ($million, 2014 $)	52.6	57.4	52.3	37.9	80.3	**757.1**
Capital expenditure ($million, 2014 $)	-	9.0	24.0	186.0	-	**219.0**

The following table summarises the NPV analysis for the Beibu Gulf Joint Venture:

Beibu Gulf Joint Venture (100%) – NPV Analysis (US$ million)				
	Discount Rate	Brent Oil Price Scenario		
		$85/bbl	$90/bbl	$95/bbl
Scenario 1 (WZ 6-12 and WZ 12-8 West Oil Fields)				
	9.5%	864.5	890.8	914.7
	10.0%	854.6	880.4	903.8
	10.5%	844.9	870.3	893.1
Scenario 2 (Scenario 1 plus WZ 12-8 East)				
	9.5%	995.2	1,034.7	1,070.6
	10.0%	982.4	1,021.1	1,056.1
	10.5%	969.9	1,007.7	1,042.0

The NPV analysis takes into account the written down tax value of assets as at 31 December 2013. Under the terms of the sale agreement with CNOOC and due to the quality of the crude oil produced, a discount of $4/bbl is applied to the Brent crude oil price.

Grant Samuel's valuation of the Beibu Gulf Joint Venture in the range $900-1,000 million reflects the NPV analysis summarised above and takes into account the following factors:

- the WZ 6-12 and WZ 12-8 West Oil Fields commenced production in March 2013. Scenario 1 assumes production of 2P reserves from these fields primarily over the period to 2027. The analysis indicates NPVs in the order of $850-900 million for the existing producing fields; and
- the WZ 12-8 East Field, while economic will have higher operating costs. This field is in pre-development and a final investment decision has not been made. The analysis indicates incremental NPVs of the order of $125-155 million on an unrisked basis.

The value range of $900-1,000 million implies the following valuation parameters:

Beibu Gulf Joint Venture (100%) – Implied Valuation Parameters (US$/mmboe)			
Multiples of	**Variable (mmboe)**	**Implied Multiple**	
		Low	**High**
Value Range (US$ million)		**900**	**1,000**
Reserves and resources at 1 January 2014			
2P reserves (WZ 6-12 and WZ 12-8 West Oil Fields)	24.4	$36.89	$40.98
2C resources (WZ 12-8 East Field)	11.5	$78.26	$86.96
2P + 2C	35.9	$25.07	$27.86
Production			
March 2013 to 31 December 2013 (actual)	3.0	$300.00	$333.33
Year ending 31 December 2014 (projected)	4.4	$204.55	$227.27

The multiples of reserves, resources and production implied by the valuation of the Beibu Gulf Joint Venture are high relative to market evidence (see Appendix 4) but not unreasonable given the low capital expenditure costs required to support the production of current 2P reserves, the potential for conversion of resources to reserves with the development of the WZ 12-8 East Field and the growth in production that would result from such development. The multiple of production for 2013 is high as it reflects only 9-10 months of production from the project.

7.3.3 Zhao Dong Joint Venture

Grant Samuel has valued ROC's aggregate interest in the Zhao Dong Joint Venture in the range $95-105 million.

Different joint venturers have different interests in each of the fields which comprise the project. Accordingly, while the descriptions of the valuation scenarios below are for 100% of the Zhao Dong Joint Venture, the NPVs generated relate to ROC's interest in the project.

Two scenarios were developed to assess the value of ROC's interest in the Zhao Dong Joint Venture:

- **Scenario 1**: assumes the production of the 2P reserves for the C/D Fields and the C4 Field with the petroleum contract terminating in 2018. The majority of production occurs in 2014 and 2015. No production is assumed from the Zhanghai/Chenghai Fields. Total oil produced over the remainder of the contract is 17.5mmbbl. Capital expenditure incurred is $280 million (2014 $) and relates primarily to the drilling of development wells. Abandonment costs of $66 million (2014 $) are assumed and, in accordance with normal practice in China, are paid across the period to 2018. Operating costs total $430 million (2014 $) over the remainder of the contract; and

- **Scenario 2**: assumes an extension of the petroleum contract until 2023 and the production of an additional 16.3mmbbls of oil from C/D Fields and C4 Field 2C resources, with around 95% of production occurring by 2020. Gas sales volumes do not extend past 2018 as an increasing proportion of gas produced is used as fuel. Capital expenditure totals $811 million (2014 $), most of which relates to drilling wells. Abandonment costs of $101 million (2014 $) are assumed and together with operating costs totalling $634 million (2014 $) are paid across the period to 2023.

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

Zhao Dong Joint Venture (100%) – Model Parameters						
	Year end 31 December					Life of Project
	2014	2015	2016	2017	2018	
Scenario 1						
Oil production (mmbbl)	6.0	5.2	3.3	2.0	1.0	**17.5**
Operating costs[57] ($million, 2014 $)	148.5	130.0	99.5	70.7	47.0	**495.7**
Capital expenditure ($million, 2014 $)	138.8	117.9	20.0	3.3	1.2	**281.2**
Scenario 2						
Oil production (mmbbl)	7.8	5.5	5.4	4.8	3.7	**33.8**
Operating costs[57] ($million, 2014 $)	160.4	134.1	114.8	92.3	62.4	**735.2**
Capital expenditure ($million, 2014 $)	155.5	224.5	171.0	143.7	116.7	**811.4**

The following table summarises the NPV analysis for ROC's aggregate interest in the Zhao Dong Joint Venture for the two scenarios:

Zhao Dong Joint Venture (ROC Aggregate Interest) – NPV Analysis (US$ million)				
	Discount Rate	Brent Oil Price Scenario		
		$85/bbl	$90/bbl	$95/bbl
Scenario 1 (contract expires 2018)				
	9.5%	101.2	102.1	102.9
	10.0%	97.0	97.8	98.6
	10.5%	91.8	92.5	93.2
Scenario 2 (contract extended to 2023)				
	9.5%	135.2	137.2	139.4
	10.0%	127.0	129.0	131.0
	10.5%	117.7	119.5	121.3

The NPV analysis takes into account the written down tax value of assets as at 31 December 2013 and a $5.00/bbl discount to the Brent crude oil price in accordance with historical oil prices received by the Zhao Dong Joint Venture.

Grant Samuel's valuation of ROC's aggregate interest in the Zhao Dong Joint Venture in the range $95-105 million reflects the NPV analysis summarised above and takes into account the following factors:

- the fields are mature and despite significant capital expenditure production will continue to decline;
- the Zhao Dong Petroleum Contract expires in September 2018; and
- there is no certainty that an extension of the petroleum contract to 2023 will be granted or that the incremental development plan will be approved (given over $500 million in capital expenditure would be required).

Consequently, Grant Samuel's valuation range is principally based on the NPVs for Scenario 1. At the top end, it allows for modest incremental value to reflect the possibility that the petroleum contract will be extended to 2023 and the project life extended.

The valuation range of $95-105 million implies the following valuation parameters:

57 Inclusive of abandonment costs which are paid across the remaining life of the project.

Zhao Dong JV (ROC Aggregate Interest) – Implied Valuation Parameters (US$/mmboe)			
Multiples of ROC's Interest in	**Variable (mmboe)**	**Implied Multiple**	
		Low	**High**
Value Range (US$ million)		**95**	**105**
Reserves and resources at 1 January 2014			
2P reserves	3.7	$25.68	$28.38
2C resources	4.6	$20.65	$22.83
2P + 2C	8.3	$11.45	$12.65
Production			
Year ended 31 December 2013 (actual)	1.5	$63.33	$70.00

The multiples of reserves, resources and production implied by the valuation of the Zhao Dong Joint Venture are high relative to market evidence (see Appendix 4) but not unreasonable, given the relatively modest capital expenditure assumed to be incurred prior to the petroleum contract expiry in 2018.

7.3.4 D35/D21/J4 PSC

Grant Samuel has valued ROC's 30% interest in the D35/D21/J4 PSC in the range $12-27 million as follows:

ROC – Value of 30% Interest in D35/D21/J4 PSC (US$ million)		
	Value Range	
	Low	**High**
Value of 30% interest in D35/D21/J4 PSC	25	40
Less: Present value of cash consideration for 30% interest	(13)	(13)
	12	**27**

On 1 April 2014, ROC announced the acquisition of a 50% participating interest in the D35/D21/J4 PSC effective 1 January 2014 for $25 million (plus $80 million in future capital commitments). On 30 May 2014 ROC announced that it had entered into a letter of intent to farm out a 20% participating interest to DIALOG (subject to PETRONAS approval). Consequently, the net cost to ROC for the 30% participating interest is $15 million (plus $48 million in future capital commitments). The initial cash consideration is to be paid in four annual instalments and the first payment was made in May 2014. As the balance sheet at 31 December 2013 is the valuation starting point, allowance has been made for the present value of the cost to ROC of the 30% interest (i.e. $13 million based on a 10% discount rate).

Given the terms of the PSC, ROC's share of production and costs varies over time and is not consistently proportionate to its nominal 30% interest. Therefore, the scenario descriptions below are for 100% of the D35/D21/J4 PSC while the NPVs set out below are for ROC's 30% interest.

The D35/D21/J4 fields are mature producing assets and ROC has acquired an interest in a redevelopment project for these fields. The redevelopment project consists of two parts, with the second part subject to a field development plan decision process proposed for 2015. Across the project there are a number of possible scenarios. For valuation purposes, four incremental scenarios were developed to assess the value of the D35/D21/J4 PSC:

- **Scenario 1 (Base and Production Enhancement Activities)**: assumes the production of existing 2P reserves as a consequence of work undertaken to arrest the decline in production of existing wells and production enhancement activities (including new wells) in relation to the D35 and J4 fields. Under this scenario the daily production rate is projected to increase to around 17,000bopd during 2015-2016 before declining to around 5,000bopd in 2019 with a production tail to 31 December 2034 (the term of the PSC). Total oil produced over the life of this scenario is 27.6mmbbl. Capital expenditure is $246 million (2014 $) (excluding exploration wells of $35 million) and is incurred primarily in 2014 and 2015 in relation to remedial well work, new wells and a new platform. Abandonment costs of $50 million (2014 $) are assumed. Operating costs are initially in the range $80-100 million (2014 $) and decline to around $75 million (2014 $) from 2020;

- **Scenario 2 (Scenario 1 plus Incremental Oil Activities)**: assumes the production of existing 2P reserves and around 40% of 2C resources as a consequence of substantial additional capital expenditure in relation to water injection and infill drilling. Under this scenario the daily production rate is projected to increase to around 15,000bopd for the period to 2020 before declining slowly to reach around 5,000bopd in 2027 with a production tail to 31 December 2034 (the term of the PSC). Total oil produced over the life of the scenario is 67.4mmbbl. Capital expenditure is $1,083 million (2014 $) (excluding exploration wells of $35 million) and is primarily incurred over the period to 2020. Abandonment costs of $130 million (2014 $) are assumed. Operating costs average around $90 million per annum (2014 $);

- **Scenario 3 (Scenario 2 plus Enhance Oil Recovery)**: assumes the production of an additional 24.5mmbbl of oil relative to Scenario 2 as a consequence of the application of enhanced oil recovery techniques to the fields. The project is conceptual and dependent on the results of the second part of the redevelopment. Total oil produced over the life of the scenario is 92.0mmbbl. Capital expenditure is $1,103 million (2014 $) (excluding exploration wells of $35 million) and is primarily incurred over the period to 2020. Abandonment costs of $130 million (2014 $) are assumed. Operating costs are initially in the range $80-100 million (2014 $) and increase to around $120 million (2014 $) from 2020; and

- **Scenario 4 (Scenario 3 plus Minor Reservoirs)**: reflects the production of an additional 31.5mmbbl of oil relative to Scenario 3 as a consequence of the introduction of water injection to the minor reservoirs developed under Scenario 2. The project is conceptual and dependent on the results of the second part of the redevelopment. Total oil produced over the life of the scenario is 123.5mmbbl. Capital expenditure is $1,399 million (2014 $) (excluding exploration wells of $35 million) and is primarily incurred over the period to 2020. Abandonment costs of $139 million (2014 $) are assumed. Operating costs are initially in the range $80-100 million (2014 $) and increase to around $150 million (2014 $) from 2020.

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

D35/D21/J4 PSC (100%) – Model Parameters

	Year end 31 December					Life of Project
	2014	2015	2016	2017	2018	
Scenario 1 (Base and Production Enhancement Activities)						
Oil production (mmbbl)	3.2	5.6	4.6	3.3	2.4	**27.6**
Operating costs ($million, 2014 $)	94.1	95.0	75.4	76.9	81.0	**2,304.3**
Capital expenditure ($million, 2014 $)	53.7	176.8	12.8	-	0.4	**245.9**
Scenario 2 (Scenario 1 plus Incremental Oil Activities)						
Oil production (mmbbl)	3.2	5.6	4.8	5.0	5.5	**67.4**
Operating costs ($million, 2014 $)	94.1	101.9	84.9	93.0	97.6	**2,809.3**
Capital expenditure ($million, 2014 $)	53.7	176.8	135.0	390.5	136.0	**1,082.9**
Scenario 3 (Scenario 2 plus Enhanced Oil Recovery)						
Oil production (mmbbl)	3.2	5.6	4.8	5.0	5.5	**92.0**
Operating costs ($million, 2014 $)	94.1	101.9	84.9	98.0	102.6	**2,967.3**
Capital expenditure ($million, 2014 $)	53.7	176.8	135.0	410.5	136.0	**1,102.9**
Scenario 4 (Scenario 3 plus Minor Reservoirs)						
Oil production (mmbbl)	3.2	5.6	4.8	5.3	7.1	**123.5**
Operating costs ($million, 2014 $)	94.1	101.9	84.9	105.4	113.6	**3,253.6**
Capital expenditure ($million, 2014 $)	53.7	176.8	196.5	586.6	160.9	**1,398.7**

The following table summarises the NPV analysis for ROC's 30% interest in the D35/D21/J4 PSC (excluding the cash consideration):

D35/D21/J4 PSC (ROC 30% Interest) – NPV Analysis (US$ million)				
	Discount Rate	Brent Oil Price Scenario		
		$85/bbl	$90/bbl	$95/bbl
Scenario 1 (Base and Production Enhancement Activities)				
	9.5%	22.7	25.8	28.7
	10.0%	22.3	25.3	28.1
	10.5%	21.9	24.8	27.6
Scenario 2 (Scenario 1 plus Incremental Oil Activities)				
	9.5%	46.5	59.3	70.8
	10.0%	43.2	55.6	66.9
	10.5%	40.2	52.2	63.1
Scenario 3 (Scenario 2 plus Enhanced Oil Recovery)				
	9.5%	108.1	122.3	135.6
	10.0%	101.5	115.3	128.1
	10.5%	95.2	108.6	121.0
Scenario 4 (Scenario 3 plus Minor Reservoirs)				
	9.5%	167.6	186.4	204.2
	10.0%	157.1	175.3	192.4
	10.5%	147.2	164.8	181.3

The NPV analysis suggests that a successful redevelopment of the fields has the potential to generate significant value. However, there is substantial uncertainty associated with the range of development outcomes beyond those contemplated in Scenario 1 and RISC has advised that, in particular, Scenarios 3 and 4 should be heavily risk weighted. Even the incremental oil activities of the redevelopment project, which involves over $800 million (2014 $) in additional capital expenditure (ROC share around $250 million), is in RISC's view subject to some technical risk.

ROC only acquired its 30% interest in the PSC in the last three months. The nominal acquisition cost was $15 million (present value of $13 million). On one view, this is the most reliable evidence as to the value of ROC's interest in the D35/D21/J4 PSC.

Consequently, Grant Samuel's valuation of ROC's 30% interest in D35/D21/J4 PSC in the range of $25-40 million is focussed on the NPV's for Scenario 1 (i.e. base and production enhancement activities) and, at the top end, allows for potential incremental value should the incremental oil activities of the redevelopment plan be undertaken.

The value range of $25-40 million implies the following valuation parameters:

D35/D21/J4 PSC (ROC 30% Interest) – Implied Valuation Parameters (US$/mmboe)			
Multiples of ROC's Interest in	Variable (mmboe)	Implied Multiple	
		Low	High
Value Range (US$ million)		**25**	**40**
Reserves and resources at 1 January 2014			
2P reserves	5.2	$2.40	$5.29
2C resources	23.9	$0.52	$1.15
2P + 2C	29.1	$0.43	$0.95

The multiples of reserves and resources are low relative to market evidence (see Appendix 4) given the significant capital expenditure required for the field redevelopment and the substantial risking that has been applied to the potential exploration of 2C resource.

7.3.5 Other Producing Assets

The aggregate value of ROC's other producing assets has been estimated by Grant Samuel to be $30-45 million as follows:

ROC – Value of Other Producing Assets (US$ million)		
	Value Range	
	Low	High
Cliff Head	20	30
Blane	8	12
Enoch	2	3
Total	**30**	**45**

The values have been assessed with regard to the field profiles provided by RISC and Grant Samuel's economic assumptions and discount rates. The value range for Blane reflects an overriding royalty obligation. No value has been attributed to the 0.25% interest in L14 (Jingemia) as its operations are currently suspended.

7.3.6 Exploration

ROC's exploration assets have been valued by RISC in the range $16-62 million (see Section 1.2 of the RISC report at Appendix 2). RISC has attributed value to Block 09/05, two prospects being considered by the Beibu Gulf Joint Venture, leads and prospects in the vicinity of the D35 field in Malaysia, Block M07 and a prospect near Cliff Head. Grant Samuel has adopted RISC's valuation range.

7.3.7 BC Petroleum

Grant Samuel has attributed a value of $65-70 million to ROC's 48% interest in BC Petroleum. This value range compares to ROC's carrying value of $67.2 million at 31 December 2013. BC Petroleum is a party to a risk sharing contract with PETRONAS in relation to the Balai Cluster. Approval has been received for Phase 1 of the plan to develop the Bentara field. First production from the field, due shortly, will trigger cost reimbursement by BC Petroleum under the risk service contract. Once it has repaid its bank funding (due by the end of 2014), BC Petroleum is expected to repay its shareholders during the year to 31 December 2015. BC Petroleum does not expect to receive material remuneration fees under the risk sharing contract. The low end of Grant Samuel's valuation range reflects a discount to book value (to allow for the time value of money and unrecoverable costs). The top end of the value range allows for upside potential in relation to remuneration fees.

7.3.8 Other Assets and Liabilities

No value has been attributed to:

- the contingent cash receivable (A$5 million) in relation to the sale of ROC's 50% interest in the BMG Project. This payment is subject to the production of hydrocarbons from a commercial development, which is not expected in the short to medium term; and
- ROC's carried forward Australian income tax losses and capital losses as they are unlikely to be recouped by ROC in the foreseeable future.

7.3.9 Corporate Costs

ROC incurs corporate costs of around $12 million that have not been included in the asset valuations. These costs include expenses associated with maintaining a head office, the executive management team and finance, human resources, administration activities and listed company costs. It is likely that a significant portion of these costs (say, 50%) could be eliminated by a corporate acquirer. An allowance of $55-60 million has been made in the valuation for the capitalised value of the residual corporate costs.

7.3.10 Adjusted Cash

At 31 December 2013, ROC had no borrowings but cash of $65.1 million. Grant Samuel has adjusted this cash balance to reflect the sale of ROC's 50% interest in the BMG Project for A$1.0 million ($0.9 million) as follows:

ROC – Adjusted Cash	
	US$ million
Cash as at 31 December 2013	65.1
Add: Cash consideration for BMG Project (received May 2014)	0.9
Adjusted Cash	**66.0**

7.3.11 Options, LTI Rights and STI Rights

Grant Samuel has reduced the ordinary equity value of ROC by $9 million to reflect the value of the options, LTI Rights and STI Rights currently on issue (including those approved on 27 May 2014 and not yet granted.

7.4 Valuation of Horizon

7.4.1 Summary

Horizon has been valued in the range US$561-721 million. The valuation represents the estimated full underlying value of Horizon assuming 100% of the company was available to be acquired and includes a premium for control. The valuation is summarised below:

Horizon – Valuation Summary (US$ million)			
	Report Section Reference	**Value Range**	
		Low	**High**
PNG development assets (PDL 10 and PRL 21)	7.4.2	300	370
New Zealand assets	7.4.3	140	160
Beibu Gulf Joint Venture	7.4.4	243	270
Exploration	7.4.5	17	55
Other assets and liabilities	7.4.6	7	7
Corporate costs (net of savings)	7.4.7	(40)	(35)
Enterprise value		**667**	**827**
Adjusted net borrowings[58]	7.4.8	(101)	(101)
Options and share appreciation rights	7.4.9	(5)	(5)
Value of equity		**561**	**721**

Grant Samuel's valuation reflects evidence as to value from DCF analysis, comparable company analysis and valuation benchmarks commonly used in the oil and gas sector. It is based on a number of assumptions (including assumptions regarding oil prices and future operational performance) which can change significantly over short periods of time. Such changes can have significant impacts on underlying value.

Grant Samuel appointed RISC as technical specialist to review Horizon's oil and gas assets. RISC's role included a review of reserves and resources, development plans, production schedules, operating costs, capital costs and exploration potential. RISC prepared valuations of Horizon's exploration interests. RISC's report is attached as Appendix 2 to this Report.

Grant Samuel's financial analysis for the oil and gas assets was based on valuation scenarios prepared in conjunction with RISC, reflecting RISC's judgements regarding the range of assumptions as to ultimate oil and gas reserves and resources, project life, production rates, operating costs and capital costs that could reasonably be adopted for valuation purposes. Grant Samuel determined the financial assumptions used in the analysis. The financial models for Horizon's assets projected nominal US$ cash flows from 1 January 2014. Present values were estimated using a range of discount rates.

Grant Samuel's valuation of Horizon implies the following valuation parameters:

58 Takes into account the $78 million receivable from Osaka Gas following the grant of PDL 10 on 30 May 2014.

Horizon – Implied Valuation Parameters (US$/mmboe)			
Multiples of	**Variable**	**Implied Multiples**	
		Low	**High**
Value Range (US$ million)			
- Equity		**561**	**721**
- Enterprise value		**667**	**827**
	(mmboe)		
Multiple of reserves and resources at 1 January 2014			
1P (proven)	11.1	$60.05	$74.54
2P (proven and probable)	15.9	$41.92	$52.04
2C (contingent resources)	79.3	$8.41	$10.43
2P + 2C	95.2	$7.00	$8.69
Production			
Year ended 31 December 2013 (actual)	1.2	$555.50	$689.50
Year ending 31 December 2014 (projected)	1.7	$392.12	$486.71
	(US$ million)		
Financial Performance for year ended 30 June 2013			
EBITDAX	27.3	24.4	30.3
EBITDA	26.7	25.0	31.0
EBIT	17.6	37.9	47.0
NPAT (as reported)	3.5	160.1	206.1

The multiples of reserves implied by the valuation are high relative to market evidence (see Appendix 4) primarily due to the substantial value attributed to Horizon's interests in PNG (for which there are only limited reserves) and due to the strong cash flows to be generated by Horizon's interests in mature assets.

The 2013 production multiples are not meaningful as production reflects only approximately six months from New Zealand as a result of the upgrade and maintenance work on FPSO Raroa and as production only commenced at the Beibu Gulf Joint Venture in March 2013. The 2014 production multiples are high as substantial value is attributable to the PNG assets which are not yet in production.

Similarly, multiples of earnings for the year ended 30 June 2013 are high and not particularly meaningful given the value attributable to the non-producing PNG assets and the limited earnings contributions in FY13 from both the New Zealand assets and the Beibu Gulf Joint Venture (production from which commenced in March 2013).

7.4.2 PNG Development Assets

Summary

Grant Samuel has valued Horizon's interests in PDL 10 and PRL 21 (i.e. the Stanley and EKT fields) in the range $300-370 million as set out below:

Horizon – Value of PNG Development Assets (PDL 10 and PRL 21) (US$ millions)		
Asset	**Value Range**	
	Low	**High**
Stanley (PDL 10)	50	70
EKT (PRL 21)	250	300
Total	**300**	**370**

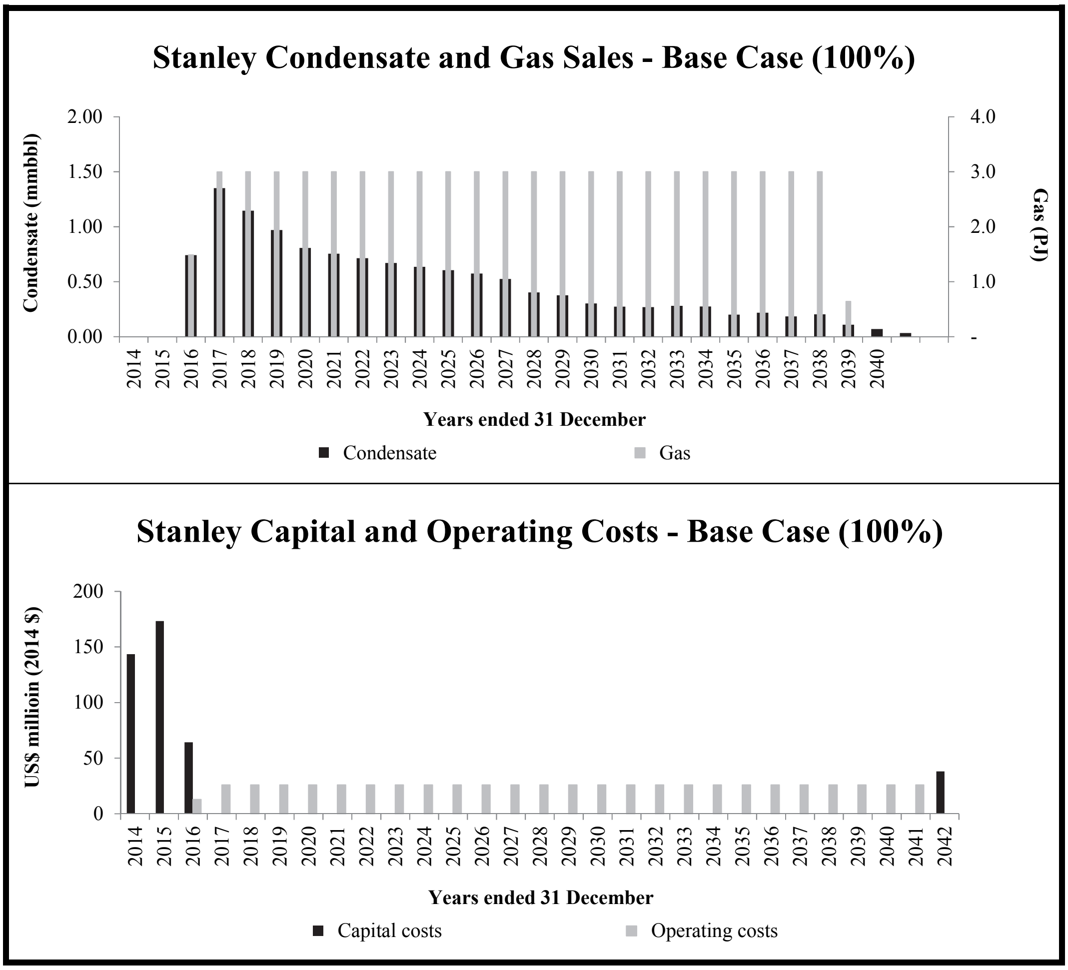
The valuation range is relatively wide, reflecting the wide range of possible outcomes for Horizon's PNG development assets. However, the valuation reflects a fundamental judgement that, notwithstanding the variety of uncertainties that apply to the development of the fields, the substantial gas resources at Stanley and EKT will ultimately be commercialised. The value attributed to the EKT fields includes the value associated with exploration upside at the Elevala Toro and Tingu Toro prospects.

Stanley Field

Grant Samuel has valued Horizon's interest in the Stanley Field (PDL 10) in the range $50-70 million.

Grant Samuel prepared DCF analysis of the Stanley Field, based on operating scenarios developed by RISC using development and production plans provided by Horizon.

The valuation of the Stanley Field focusses on a base case scenario that assumes the production of condensate volumes equal to 2P condensate reserves as at 31 December 2013 (with a very small contribution from 2C condensate resources), the sale to Ok Tedi of a modest volume of the gas produced and the re-injection of the excess gas volumes to provide pressure support. RISC has adopted Horizon's assumptions in relation to condensate and gas inventories and operating costs but has adjusted capital expenditure assumptions to reflect cost escalation due to project delays and has provided for increased contingencies. RISC has also included abandonment costs of $38 million to be incurred in 2042. As the gas is assumed to be sold at the production facility fence, the Stanley joint venture participants are not liable for any capital or operating costs in relation to the sale gas. Development of the field and construction of the processing plant and facilities are assumed to be completed by mid 2016 with production starting shortly thereafter. Production ceases in 2041.



The following table summarises the condensate and gas production and capital and operating costs for the base case:

Stanley Field (100%) – Model Parameters								
	Year ended 31 December							Life of Project
	2014	2015	2016	2017	2018	2019	2020+	
Condensate sales (mmbbl)	-	-	0.7	1.4	1.1	1.0	8.5	**12.7**
Gas sales (PJ)	-	-	1.5	3.0	3.0	3.0	57.6	**68.1**
Capital expenditure ($ million, 2014 $)	143	173	64	-	-	-	38	**419**
Operating costs ($ million, 2014 $)	-	-	13	26	26	26	572	**663**

Grant Samuel has calculated NPVs for the base case for a range of assumptions regarding future oil prices and discount rates as follows:

Stanley Field (Horizon Interest post PNG Government Back In) – NPV Analysis (US$ million)				
Case	Discount Rate	Brent Oil Price Scenarios		
		$85/bbl	$90/bbl	$95/bbl
Base	9.5%	39	45	51
	10.0%	36	42	47
	10.5%	33	38	44

The NPV analysis assumes gas sales at $7.25/GJ and condensate sales at a slight discount ($2.00) to the Brent oil price. The PNG Government is assumed to back in to the project in December 2014 by paying its share of past costs.

Gas sales contribute most of the value in the base case scenario, with a liquids stripping only case (i.e. a case assuming zero gas sales) displaying roughly break even economics. On the other hand, the base case scenario assumes the sale of only around 20% of the total gas produced, with the balance re-injected. There is an opportunity to sell significant additional gas, potentially to the Frieda River mining project, to local towns or as feedstock for an LNG project. Grant Samuel has modelled a scenario that assumes the sale of an additional 15PJ of gas per annum, at lower gas prices. The results of this DCF analysis are set out the in the following table:

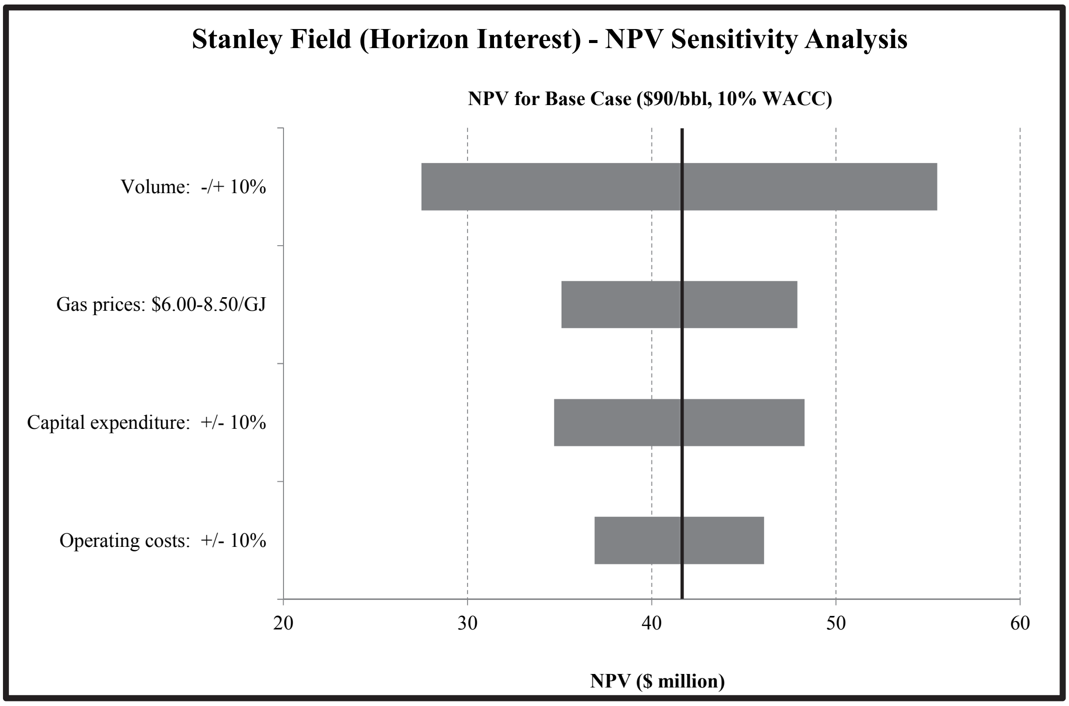
Stanley Field (Horizon Interest post PNG Government Back In) – NPV Analysis (US$ million)				
Case	Discount Rate	Brent Oil Price Scenarios		
		$85/bbl	$90/bbl	$95/bbl
Additional Gas Sales	9.5%	127	131	136
	10.0%	119	123	128
	10.5%	111	116	120

This case suggests that additional gas sales could add more than $80 million of value.

Grant Samuel has also assessed the sensitivity of its base case scenario (assuming $90/bbl Brent oil price and a 10% discount rate) to the following changes in key variables:

- variations of +/- 10% in production volumes. The recoverable condensate and gas inventory and well performance assumptions are underpinned by statistical analysis, which is by its nature subject to uncertainty;
- gas price in the range $6.00-8.50/GJ reflecting an assessed range of potential outcomes of commercial negotiations;
- variation of +/- 10% in capital costs to capture the uncertainty relating to the capital cost estimates; and
- variations of +/- 10% in operating costs.

The outcome of the sensitivity analysis is summarised below:



These sensitivities do not represent the full range of potential value outcomes for Horizon's Stanley Field interests. They are simply theoretical indicators of the sensitivity of the NPVs derived from the DCF analysis.

Grant Samuel's valuation of $50-70 million for Horizon's interest in the Stanley Field reflects the fact that there are not as yet any settled terms for the sale of gas to Ok Tedi and the substantial but far less certain upside relating to the sale of additional gas (whether to the Frieda River project or other users). While Grant Samuel's modelling suggests that a larger scale gas commercialisation could deliver around $80 million of incremental value, a delay in the commencement of gas sales (to Frieda River or other large scale customers) by, say, three years, would reduce this incremental value by approximately $20 million. On other hand, it is reasonable to assume that this additional gas will ultimately be commercialised, if not through sale to an industrial user or for power supply to local towns, then as feedstock for an LNG gas project.

In addition, Grant Samuel's value for the Stanley Field takes into account:

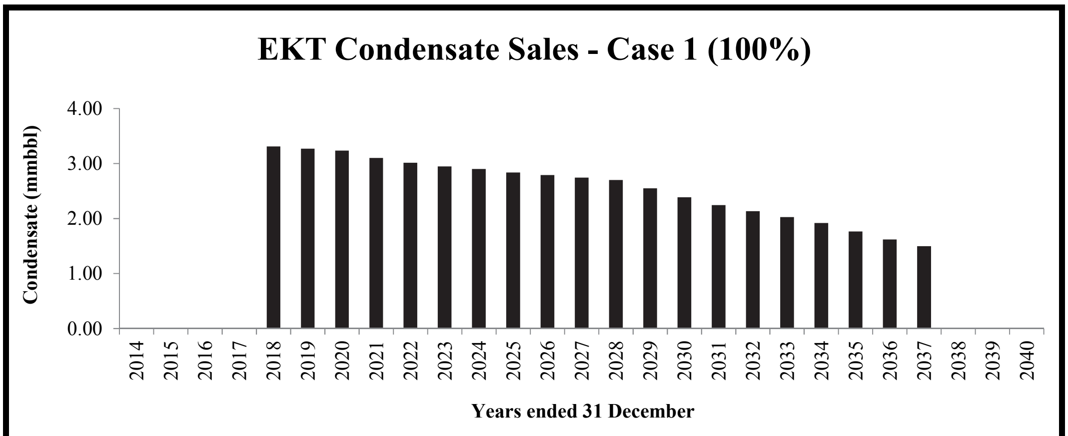
- the granting of the PDL for the project on 30 May 2014 suggests that there is now significantly reduced development risk, with both the project partners and the PNG Government committed to the development;
- the proposed processing facilities are of conventional design and there appears to be limited technical risk associated with the development;
- Horizon has $151.9 million in PNG carried forward income tax losses (of which approximately 40% are to be transferred to Osaka Gas); and
- the resumption of operatorship of the project by Talisman (from Horizon) suggests that there is some risk of delays in the development of the project, notwithstanding that Talisman is an experienced operator.

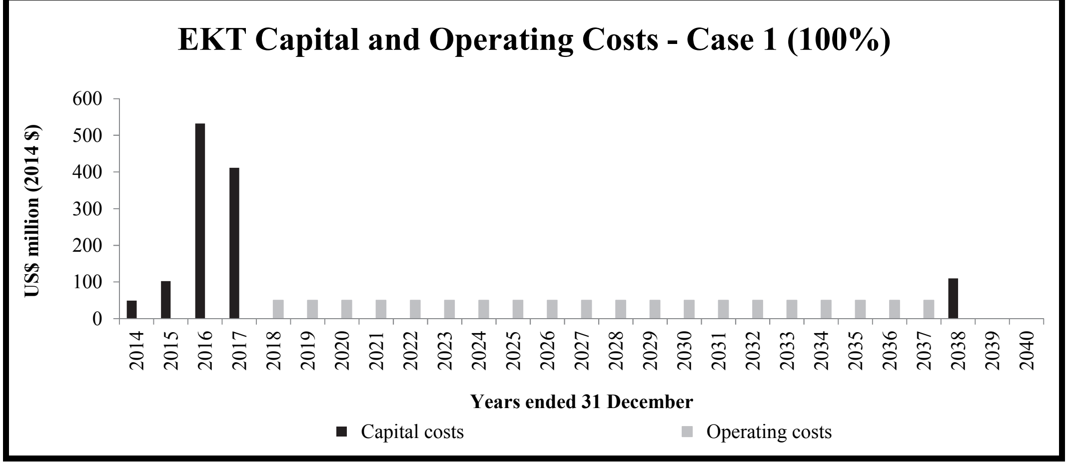
EKT Fields

Grant Samuel has valued Horizon's interest in the EKT Fields in the range $250-300 million.

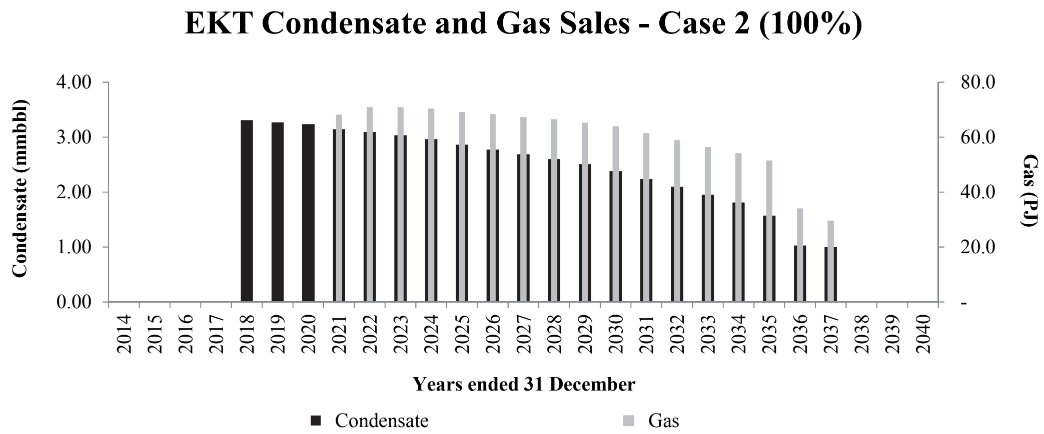
Grant Samuel prepared DCF analysis for the EKT Fields based on two operating scenarios developed by RISC using development and production plans provided by Horizon. The cases contemplate a liquids stripping scenario ("Case 1") and a liquids stripping and gas export scenario ("Case 2").

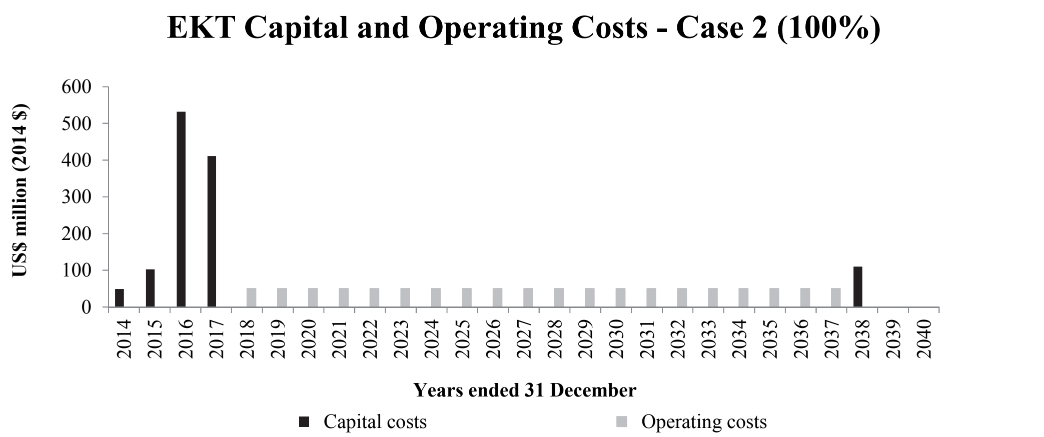
The liquids stripping scenario is based on the production of condensate volumes equal to current 2C contingent resources and the re-injection of the gas into the reservoir. RISC has essentially adopted Horizon's condensate production and operating costs assumptions and has made minor adjustments to development capital expenditure assumptions. RISC has also included abandonment costs of $110 million, to be spent in 2038. Development of the field and construction of the processing plant and facilities are assumed to be completed in late 2017 with production starting shortly thereafter. Production finishes in 2037.





Case 2 is similar to Case 1 but assumes that gas sales commence three years after condensate sales. It is assumed that the gas is sold as feedstock for a medium sized LNG facility (potentially barge-mounted and located at Mugumugu on the Fly River or on the southern coast). Gas is assumed to be sold on an ex-field basis, so no additional capital expenditure is required (i.e. the pipeline and other transport infrastructure, together with the LNG plant, will be third party owned, with the EKT participants receiving a net back price that allows the owners to recover the cost of the transport infrastructure and the LNG facility).





The condensate and gas production and capital and operating costs for the cases are set out below:

EKT (100%) – Model Parameters								
	Year ended 31 December							Life of Project
	2014	2015	2016	2017	2018	2019	2020+	
Case 1								
Condensate sales (mmbbl)	-	-	-	-	3.3	3.3	44.4	**51.0**
Gas sales (PJ)	-	-	-	-	-	-	-	**-**
Capital expenditure ($million, 2014 $)	49	103	532	411	-	-	110	**1,205**
Operating costs ($million, 2014 $)	-	-	-	-	50	50	900	**1,000**
Case 2								
Condensate sales (mmbbl)	-	-	-	-	3.3	3.3	43.0	**49.6**
Gas sales (PJ)	-	-	-	-	-	-	1,024	**1,024**
Capital expenditure ($million, 2014 $)	49	103	532	411	-	-	110	**1,205**
Operating costs ($million, 2014 $)	-	-	-	-	50	50	900	**1,000**

Grant Samuel has calculated NPVs for the two cases for a range of assumptions regarding future oil prices and discount rates:

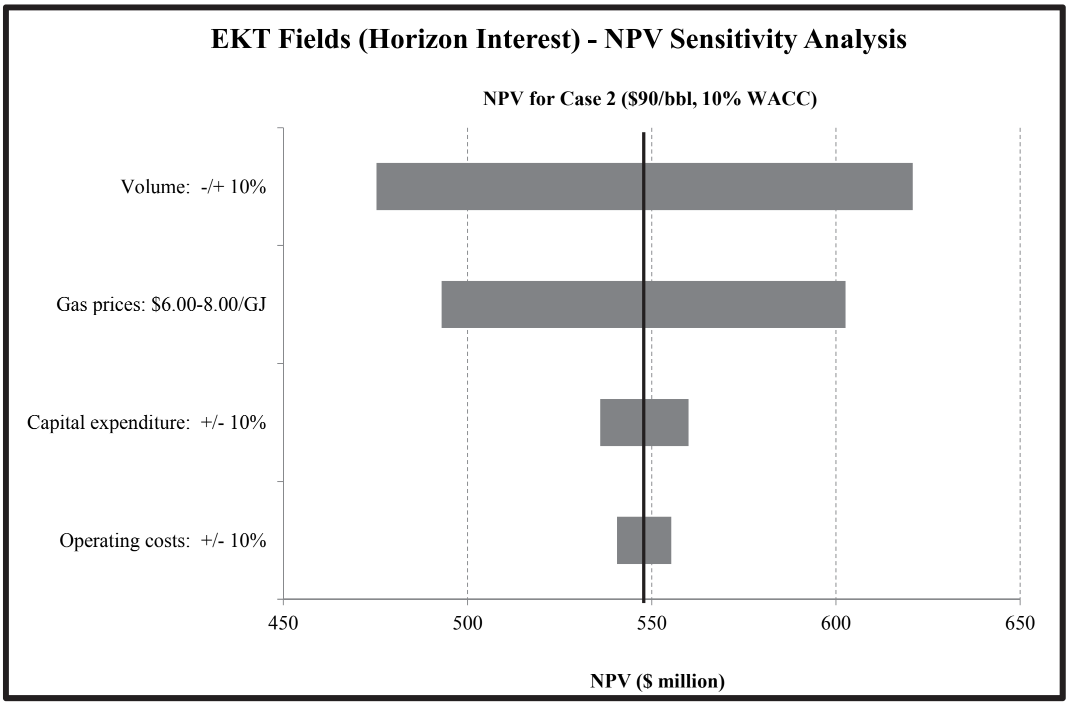
EKT Field (Horizon Interest post PNG Government Back In) – NPV Analysis (US$ million)				
Case	Discount Rate	Brent Oil Price Scenarios		
		$85/bbl	$90/bbl	$95/bbl
Case 1	9.5%	119	139	158
	10.0%	108	126	145
	10.5%	97	115	132
Case 2	9.5%	565	586	607
	10.0%	528	548	568
	10.5%	494	513	531

Analysis undertaken by Horizon and RISC suggests that for oil prices around $90/bbl, the EKT project could expect to sell its gas as feedstock for a medium scale LNG project on the basis of a netback price in the range of $6.00-8.00/GJ. The NPVs shown above are based on $7.00/GJ (the midpoint of that range). The condensate is assumed to be sold at a slight discount ($2.00) to the Brent oil price. It is assumed that the PNG Government buys into the project in January 2016 by paying its share of past costs. The DCF analysis takes into account the cash flows resulting from Horizon's disproportionate entitlement to condensate production, which arises as a result of the terms of the Osaka Gas transaction.

Grant Samuel has assessed the sensitivity of Scenario 2 (i.e. the gas export scenario) on the assumption of $90/bbl Brent oil prices and a 10% discount rate, to changes in key variables as follows:

- variations of +/- 10% in production volumes. The recoverable condensate and gas inventory and well performance assumptions are underpinned by statistical analysis, which is by its nature subject to uncertainty;
- pricing of the gas in the range $6.00-8.00/GJ, reflecting the expected range of potential outcomes;
- variation of +/- 10% in capital costs to capture the uncertainty relating to the capital cost estimates; and
- variations of +/- 10% in operating costs.

The outcome of the sensitivity analysis is summarised below:



These sensitivities do not represent the full range of potential value outcomes for Horizon's EKT Fields interests. They are simply theoretical indicators of the sensitivity of the NPVs derived from the DCF analysis.

The DCF analysis suggests a value of around $550 million (Horizon's share) for a full field development including gas export but a far more modest value of around $120 million for a liquids stripping only development. These values are unrisked and need to be adjusted to reflect the range of uncertainties to which the EKT project remains exposed. In particular:

- the fields have not yet been fully appraised and development studies remain to be completed. The DCF analysis is based on 2C resources and capital and operating costs are not yet precisely defined;
- any development of the fields is still subject to permitting;
- the gas export development is subject to a range of risks and uncertainties. In particular:
  - around 2tcf of gas is likely to be required to support a standalone medium sized LNG plant;
  - depending on the volume of gas sales from the Stanley Field to local customers, the PDL 10/ PRL 21 participants currently have around 1.0-1.3tcf available. Accordingly, to underwrite the economics of an LNG based gas export scheme, there will be a need for additional exploration success or some form of aggregation with gas owned by other parties;
  - the presence of multiple joint venture partners with potentially non-aligned objectives may make it more difficult to achieve the consensus required to move to a development decision. A delay of, say, three years reduces the calculated NPVs by approximately $140 million based on mid case assumptions in Case 2 (assuming $90/bbl Brent oil price and a 10% discount rate); and
  - the estimated capital costs for the EKT liquids stripping project are around $1.1 billion. RISC's estimate of capital expenditure for a Mugumugu based LNG development is around $2 billion (although this capital expenditure is assumed to be funded by separate participants in the LNG project). There will need to be significant mitigation of project risks before any commitment to capital costs of this magnitude is made;
- the modelling assumes that the "liquids stripping only" scenario is an independent development scenario, capable of being developed without gas exports. There are strong reasons for the joint venture participants to progress with a liquids stripping development in advance of any gas export arrangements, in part because the economics appear reasonable but more importantly because in the absence of a development they would be at risk of losing their tenure. On the other hand, the economics of a liquids stripping development may not be compelling for some joint venture participants and they may wish to defer development until the broader gas export development was imminent. Any linkage between the liquids stripping development and the gas export development increases the risks associated with the liquids stripping development;
- current estimates of net back pricing for gas sales are no more than indicative, given that the configuration of any LNG project is yet to be determined; and
- the development is subject to general PNG sovereign risk, although this is arguably mitigated to some extent by the government imperative to promote development in the Western Province and by the successful development of the PNG LNG project.

On the other hand, there are factors that suggest that it is highly likely that the gas will ultimately be commercialised:

- as potential gas off takers, Osaka Gas and Mitsubishi Corporation have a real incentive to promote a gas development;
- Mitsubishi Corporation and Talisman have joint interests in existing resources further to the south in the Foreland Basin, which, when combined with the Stanley/EKT resources, could already provide sufficient gas to support an LNG project;
- there is a realistic possibility that close to 2tcf of gas will be delineated in the vicinity of PRL 21 through further exploration success;
- the proposed development is of proven design and neither the pipeline construction nor the LNG facility involve significant technical risk; and
- commercialisation of the gas is not dependent on the development of a LNG export facility as contemplated by Horizon. Depending on economics, the gas could instead be aggregated with Talisman/Mitsubishi Corporation gas resources and used to support a Talisman/Mitsubishi Corporation sponsored development. Alternatively, depending on the

route adopted for a pipeline from the P'nyang gas field, there may be an opportunity to sell the gas into a third or subsequent PNG LNG train. There may be other opportunities to aggregate with P'nyang gas or with Elk/Antelope gas to support a separate Foreland Basin LNG facility.

Accordingly, while the gas sales development scenario that has been modelled represents a credible path to commercialisation of the gas, it is only representative of a range of opportunities for gas monetisation. Moreover, while the analysis has been based on the assumption that Horizon would not participate in the LNG project itself (i.e. Horizon would only be a supplier of gas at netback prices) there would potentially be an opportunity for Horizon to participate in the LNG project and capture additional value.

In the context of these uncertainties, and given the relatively early stage of development of the assets, any valuation judgement is subjective. Grant Samuel's valuation of Horizon's interest in EKT in the range \$250-300 million represents a deep discount to calculated NPVs: at the bottom end of the range, it is less than 50% of the calculated NPV for a gas export based development (based on mid-case oil and discount rate assumption). The valuation range of \$250-300 million takes into account the exploration value that RISC has estimated for the Elevala Toro and Tingu Toro prospects (\$nil-20 million).

Osaka Gas Transaction

In May 2013 Horizon announced the sale to Osaka Gas of 40% of its interests in PRL 4 (now PDL 10), PRL 21 and PPL 259 in return for:

- a cash payment of \$74 million. Of this, \$20 million was paid as a deposit in May 2013 and the balance of \$54 million is to be paid in June 2014 following the granting of PDL 10 on 30 May 2014;
- an additional \$130 million cash payment contingent upon a positive final investment decision by Osaka Gas of LNG development or tolling/substituting equity gas through third party infrastructure (of which \$50 million is payable on decision and \$80 million paid in line with capital costs for the LNG project); and
- an entitlement to Osaka Gas' share of condensate production (post PNG Government back in) from the Stanley, Elevala, Ketu and part of the Tingu fields above a cumulative threshold of 6.7mmbbl.

The total cash consideration of \$204 million (i.e. the \$74 million initial payment plus the \$130 million contingent payment) implies a value for Horizon's residual interest in PDL 10, PRL 21 and PPL 259 of \$306 million, before taking into account the time value of money and any risking for the contingent payment.

Grant Samuel has estimated that Horizon's disproportionate share of condensate production has an unrisked NPV of around \$70 million. Whilst recognising that there is an element of inconsistency as definitionally the NPV is adjusted for the time value of money, including this \$70 million in the total consideration payable by Osaka Gas (i.e. \$274 million) increases the value implied for Horizon's residual interest in PDL 10, PRL 21 and PPL 259 to \$411 million.

However, estimates of the value of Horizon's residual interest in PDL 10, PRL 21 and PPL 259 based on the terms of the Osaka Gas transaction need to adjust for the risks associated with the \$130 million in contingent payments and that these payments would only be received some years into the future. In addition, the following factors need to be taken into account:

- the granting of PDL 10 has reduced the risk of the development (although in some sense this was reflected in the initial cash payment, which was contingent on the grant of the PDL);
- the broader PNG sovereign risk reduction associated with the successful commencement of production from PNG LNG;
- additional expenditure on the project during 2013 and early 2014;
- exploration success at EKT;

- the growth in EKT resources based on additional work done since the Osaka Gas transaction was announced; and
- the "roll forward" of values from early 2013 to mid June 2014 (i.e. the reduction in the discounting of future cash flows).

Having regard to these factors, the terms of the Osaka Gas transaction provide general support for Grant Samuel's valuation of Horizon's interest in PDL 10 and PRL 21 of $300-370 million.

Exploration

Horizon's exploration interests in PNG consist of a 27% interest in the Elevala Toro and Tingu Toro prospects, located in the Elevala/Tingu field in PRL 21, a 35% interest in PPL 259 (which hosts the Nama target), a 50% stake in PPL 430 and 90% stakes in each of PPL 372 and PPL 373. The value of the Elevala Toro and Tingu Toro prospects is reflected in the valuation range for the EKT fields above. The value for Horizon's exploration interests in PPLs 259, 430, 372 and 373 have been valued by RISC as set out in section 7.4.5.

7.4.3 New Zealand

Grant Samuel has valued 100% of PMP 38160 in the range $1,400-1,600 million. This implies a value for Horizon's 10% interest of $140-160 million. No allowance has been made for the possibility that an acquirer may discount the value of Horizon's interest in PMP 38610, given the size of the interest and that Horizon is not the operator.

Two scenarios were developed for 100% of PMP 38160:

- **Scenario 1:** primarily based on production of 2P reserves for the Maari/Manaia Fields. Production in 2014 includes some planned downtime for maintenance and operations. Production then continues until 2030 though there is still significant tail production beyond this period. Total oil produced over the life of the model is 50.8mmbbl. Capital expenditure in 2014 totals $238 million and relates primarily to development of wells (Maari Deep and Maari full field) and the water injection project. Abandonment costs of $70 million are assumed in 2031; and
- **Scenario 2**: is based on Scenario 1 however assumes no benefit from the planned water injection at the Maari Moki field (i.e. the water injection fails to boost oil production). Oil produced over the life of the operation is 44mmbbl and capital expenditure totals $271 million. There is no change to operating costs, capital expenditure or abandonment costs from Scenario 1.

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

PMP 38610 (100%) – Model Parameters

	Year end 31 December					Life of Project
	2014	2015	2016	2017	2018	
Scenario 1						
Oil production (mmbbl)	4.7	6.6	6.1	5.5	4.6	**50.8**
Operating costs ($million, 2014 $))	103.1	74.0	77.1	72.8	73.1	**1,222.5**
Capital expenditure ($million, 2014 $)	237.6	31.3	2.3	-	-	**271.3**
Scenario 2						
Oil production (mmbbl)	4.6	6.1	5.1	4.2	3.4	**44.0**
Operating costs ($million, 2014 $)	103.1	74.0	77.1	72.8	73.1	**1,222.5**
Capital expenditure ($million, 2014 $)	237.6	31.3	2.3	-	-	**271.3**

The following table summarises the results of the NPV analysis for PMP 38610 for the two scenarios:

PMP 38610 (100%) – NPV Analysis (US$ million)				
	Discount Rate	Brent Oil Price Scenario		
		$85/bbl	$90/bbl	$95/bbl
Scenario 1				
	9.5%	1,465.5	1,555.3	1,637.5
	10.0%	1,436.5	1,525.2	1,605.3
	10.5%	1,409.4	1,496.0	1,574.1
Scenario 2				
	9.5%	1,203.2	1,280.3	1,349.4
	10.0%	1,180.7	1,255.9	1,323.3
	10.5%	1,158.9	1,232.3	1,298.0

The NPV analysis takes into account the written down tax value of assets as at 31 December 2013. Due to the quality of the crude oil produced, a $5-6/bbl premium is applied to the Brent crude oil price.

Grant Samuel's value for 100% of PMP 38610 in the range $1,400-1,600 million is based on Scenario 1 but takes into account that:

- Scenario 1 assumes the success of the planned water injection project, it is based on 2P reserves which were downgraded to reflect the fact that the current water injection scheme had failed to generate expected benefits;
- Scenario 2 is a downside case which assumes the planned water injection project is not successful. However, it is possible that the project could deliver additional oil but not to the level implied by Scenario 1. In this regard, Horizon has noted that during 2014 to date field production has consistently exceeded the forecast of reserves by approximately 15%; and
- RISC has valued Horizon's 10% interest in the exploration potential in the Whio Prospect in the range $7.6-15.2 million. This implies a value of $76-152 million for 100% of the Whio Prospect.

The value range of $1,400-1,600 million implies the following valuation parameters:

PMP 38610 (100%) – Implied Valuation Parameters (US$/mmboe)			
Multiples of	Variable (mmboe)	Implied Multiple	
		Low	High
Value Range (US$ million)		**1,400**	**1,600**
Reserves and resources at 1 January 2014			
2P reserves	59.5	$23.53	$26.89
2C resources	-	na	na
2P + 2C	59.5	$23.53	$26.89
Production			
Year ended 31 December 2013 (actual)	1.8	$777.78	$888.89
Year ending 31 December 2014 (projected)	4.7	$297.87	$340.43

The multiples of reserves and resources implied by the valuation are high relative to market evidence (see Appendix 4) as significant value is allowed for the success of the growth projects currently being implemented. In addition, the value reflects the Whio Prospect for which no 2C resources are recognised. The multiples of production are not meaningful for 2013 as there was no production between mid July and mid December as a result of the upgrade and repair work to the FPSO Raroa.

7.4.4 Beibu Gulf Joint Venture

Grant Samuel has valued 100% of the Beibu Gulf Joint Venture in the range $900-1,000 million (refer Section 6.3.2). This implies a value for Horizon's 26.95% interest[59] of $243-270 million. No allowance has been made for the possibility that an acquirer may discount the value of Horizon's interest in the Beibu Gulf Joint Venture, given the size of the interest and that Horizon is not the operator.

7.4.5 Exploration

Horizon's exploration assets have been valued by RISC in the range $23.7-90.4 million (see Section 1.2 of the RISC report at Appendix 2). RISC has attributed value to the Whio Prospect in New Zealand, two prospects being considered by the Beibu Gulf Joint Venture and the potential in PRL 21, PPL 259, PPL 430, PPL 373 and PPL 373 in PNG.

The values attributed to the Whio Prospect in New Zealand and PRL 21 (PNG) exploration assets have been allowed for in Grant Samuel's valuation of these assets. However, as Horizon's exploration interest in the Beibu Gulf Joint Venture and other PNG interests are different to its interest in the projects, they have been valued separately. Grant Samuel has adopted RISC's valuation range for the Beibu Gulf Joint Venture exploration asset and the other PNG exploration assets as follows:

Horizon – Other Exploration Assets (US$ million)			
Asset	Horizon Interest	Value Range	
		Low	High
Beibu Gulf Joint Venture	55%	-	8
PNG			
- PPL 259	35%	15	45
- PPL 372 and 372	90%	1	1
- PPL 430	50%	1	1
		17	**47**
Total		**17**	**55**

7.4.6 Other Assets and Liabilities

Grant Samuel has attributed a value of $7 million to Horizon's other assets and liabilities. This includes allowance for:

- the mark to market value of its oil price derivative financial instruments; and
- its share of an insurance claim relating to repair costs incurred on the FPSO Raroa in PMP 38610. No value has been attributed to the insurance claim for lost revenue.

No value has been attributed to Horizon's Australian carried forward income tax losses and capital losses or the United States carried forward income tax losses. Horizon's carried forward income tax losses in PNG are allowed for in the value of the PNG assets.

7.4.7 Corporate Costs

Horizon incurs corporate costs of around $7-8 million per annum that have not been included in the asset valuations. These costs include expenses associated with maintaining a head office, the executive management team and finance, human resources, administration activities and listed company costs. It is likely that a significant portion of these costs (say, 50%) could be eliminated by a corporate acquirer. An allowance of $35-40 million has been made in the valuation for the capitalised value of the residual corporate costs.

[59] Assuming that CNOOC exercises its right to participate to 51% in the WZ 12-8 East Field development and assume operatorship (i.e. Horizon's interest in this development would decline from 55% to 26.95%).

7.4.8 Adjusted Net Borrowings

Horizon's net borrowings for valuation purposes is summarised in the following table:

Horizon – Adjusted Net Borrowings	
	US$ million
Cash and cash equivalents as at 31 December 2013	37
Bank debt as at 31 December 2013	(134)
Convertible bonds	(91)
	(188)
Osaka Gas transaction receivable	78
Cash received from partly paid shares and on exercise of vested and exercisable options	9
Net Borrowings	**(101)**

Grant Samuel has attributed a value of $91 million to Horizon's listed convertible bonds based on the closing price for the bonds on 28 April 2014 (the day prior to the announcement of the Merger) of 113.31. This compares to the book value (before capitalised borrowing costs) of the convertible bonds as at 31 December 2013 ($87.3 million)[60] and the current market value of the convertible bonds of $90.2 million (based on a price of 112.778 on 13 June 2014).

Following the grant of PDL 10 on 30 May 2014, the remainder of the initial transaction payment, together with its share of field costs since 1 January 2013, is now payable by Osaka Gas. An amount of $78 million is to be received by Horizon during June 2014.

Net borrowings have been adjusted for the cash owed on the partly paid shares and on exercise of vested and exercisable options of $9 million.

7.4.9 Options and Share Appreciation Rights

Grant Samuel has reduced the ordinary equity value of Horizon by $5 million to reflect the value of the unvested options and share appreciation rights currently on issue.

60 The market value of the convertible bonds at 31 December 2013 was $86 million based on a last trading price of 107.24.

8 Evaluation of the Merger

8.1 Conclusion

In Grant Samuel's opinion, the Merger terms are fair to ROC shareholders. The Merger benefits are collectively significant and outweigh the disadvantages. Accordingly, the Merger is in the best interests of ROC shareholders.

On the basis of sharemarket values and Grant Samuel's assessment of the full underlying values of ROC and Horizon, the aggregate interest of ROC shareholders in New ROC will be approximately proportionate to ROC's contribution of value to the merged company. The terms of the Merger are therefore fair to ROC shareholders.

It should be recognised that estimates of value of the assets of ROC and Horizon are inherently uncertain. Estimates of value of oil and gas assets (and particularly development and exploration assets) can change relatively quickly, potentially by material amounts, and are dependent upon such factors as future oil prices, development progress and appraisal and exploration success. In particular, Horizon's PNG development assets represent a material proportion of Horizon's overall value. A relatively wide range of development outcomes (and therefore values) for these assets is credible. Judgements regarding the current value of these assets are subjective.

Relative to Horizon, the value of ROC is less sensitive to movements in oil prices, as ROC held significant cash at 31 December 2013 (representing approximately 18% of its market capitalisation prior to announcement of the Merger) while Horizon had net debt. Similarly, ROC is probably less exposed to changes in overall market sentiment towards the oil and gas sector.

Accordingly, while Grant Samuel believes that the terms of the Merger are fair to ROC shareholders, this conclusion could change for different market conditions. In particular, the Merger terms would become less attractive for ROC shareholders if oil prices were to fall materially or if the PNG investment environment was to significantly deteriorate.

The Merger offers a number of benefits for ROC shareholders. New ROC will be a much larger company than ROC on a standalone basis and its shares should enjoy significantly greater liquidity. New ROC should be able to access both equity and debt capital on more attractive terms than those available to ROC on a standalone basis. New ROC will have a broader array of assets within a geographically more diversified asset portfolio (although some shareholders may prefer to achieve this diversification directly through their own investment decisions). While merger synergies are not expected to be material, it is likely that some corporate cost reductions will be achieved.

Importantly, the Merger will provide ROC with significant growth options. ROC on a standalone basis has relatively limited opportunities for growth (notwithstanding its recent farm in to a production sharing contract offshore Malaysia). Its asset portfolio largely consists of producing assets that are approaching or in production decline. By comparison, Horizon's PNG assets have the potential to deliver substantial production growth in the medium term and offer considerable "blue sky" upside beyond that. More generally, the size and enhanced financial flexibility of New ROC should give it the capacity to consider larger and potentially riskier acquisitions, developments or other growth initiatives than would have been appropriate for ROC on a standalone basis.

All these factors suggest that there is a realistic prospect that the Merger will result in a market re-rating of New ROC. In this regard, ROC shares are trading at prices approximately 25% higher than immediately before the announcement of the Merger, while the combined market capitalisation of ROC and Horizon has grown by around 18%[61] since the announcement of the Merger. While the potential for a market re-rating is generally difficult to quantify, the share price performance of both ROC and Horizon since the announcement of the Merger suggests that the re-

61 Based on the Horizon share price on 22 April 2014.

rating opportunity is significant. ROC (and Horizon) shareholders would stand to lose the recent share price appreciation if the Merger did not proceed.

Moreover, ROC shareholders will not give up the opportunity to realise a full premium for control at some later stage. While ROC shareholders will in aggregate represent a minority (42%) in New ROC, the Merger will not result in passing of control in the sense of the acquisition of a controlling shareholding by any single shareholder. The share register of New ROC will arguably be more open than the current ROC register, with no shareholder holding more than 14%[62] of New ROC. ROC shareholders will retain an opportunity to realise a full premium through a subsequent change of control transaction for New ROC. On one view the prospects of such a transaction should be enhanced, given the upside potential, ultimate scale and corporate appeal of the PNG assets.

ROC shareholders should understand that the Merger will change the investment characteristics of their holdings. In essence, relative to ROC on a standalone basis, New ROC will have greater growth opportunities but will face additional development and other risks. In the short to medium term at least, New ROC is likely to have lower free cash flow, given the need to fund the development of its PNG assets, although successful development of the PNG assets would deliver material growth in earnings and free cash flows in the longer term. The market response to the Merger announcement and Grant Samuel's valuation analysis suggests that the net effect of these changes is broadly neutral or potentially marginally positive from a short term value perspective. However, it would clearly be open to investors with different risk appetites or a focus on short term earnings versus longer term growth to take a different view on the net benefit to ROC shareholders.

In Grant Samuel's opinion, the Merger benefits are collectively significant and outweigh the disadvantages. The Merger is in the best interests of ROC shareholders.

8.2 Approach to Evaluation

The Merger is not a "control transaction" as that term is defined in ASIC regulatory guides. The Merger terms have been agreed on a "nil premium" basis, with ROC and Horizon shareholders to hold interests in New ROC that are consistent with the relative sharemarket values of the two companies before the announcement of the Merger. Accordingly, Grant Samuel has assessed the Merger by:

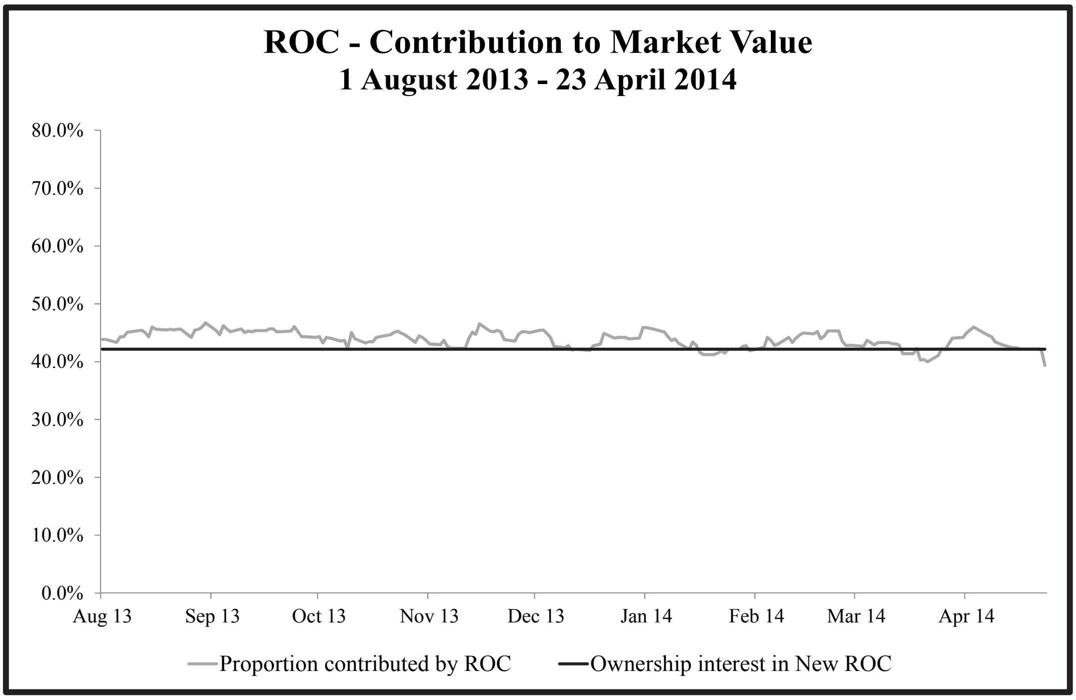
- comparing the relative values contributed by ROC and Horizon shareholders with the interests that they will hold in New ROC. The value contributions have been assessed on the basis of:
  - sharemarket values; and
  - Grant Samuel's estimates of full underlying value;
- comparing the relative contributions of ROC and Horizon on the basis of other parameters such as reserves, resources, production and earnings;
- evaluating the benefits expected to be realised as a result of the Merger;
- considering any disadvantages of the Merger; and
- assessing whether, overall, ROC shareholders will be better off if the Merger proceeds than if it does not.

8.3 Relative Contributions – Sharemarket Values

There is an active, well-informed market for shares in both ROC and Horizon. Accordingly, sharemarket values provide an objective measure of the value contributions to be made by ROC and Horizon shareholders to New ROC.

[62] Based on substantial shareholder notices at 13 June 2014.

ROC's contribution to the aggregate sharemarket value (based on daily closing prices) of the two companies since July 2013 is shown in the following chart:



Source: IRESS and Grant Samuel analysis
Notes: (1) The analysis is for the period following Horizon's issue of 162.2 million shares (approximately 14% of issued capital) at a price of A$0.33 to raise A$53.5 million.
(2) Market capitalisation calculated by reference to fully paid shares currently on issue only. On this basis, ROC shareholders will collectively hold a 42.2% interest in New ROC.

The following table shows VWAPs for ROC and Horizon shares, the notional sharemarket capitalisations of the two companies and their contributions of sharemarket value to New ROC, for various periods before the announcement of the Merger:

Contribution of Sharemarket Value[63]

Period	ROC			Horizon		
	VWAP A$	Market Capitalisation (A$ million)	Contribution %	VWAP A$	Market Capitalisation (A$ million)	Contribution %
23 April 2014	0.459	315.6	40.9%	0.350	455.7	59.1%
1 week to 23 April 2014	0.462	317.7	41.4%	0.346	450.5	58.6%
1 month to 23 April 2014	0.463	318.4	43.0%	0.324	421.8	57.0%
3 months to 23 April 2014	0.462	317.7	43.0%	0.323	420.5	57.0%
6 months to 23 April 2014	0.459	315.6	43.3%	0.318	414.0	56.7%

Given the active markets in both ROC and Horizon, it is reasonable to conclude that recent share market values reflect the market's consensus view on the values of both companies. In general, the most recent share prices reflect the "best" market estimate of values, because they incorporate the most recent information on commodity markets, price expectations, operational performance and other matters impacting on market assessments of value.

ROC released its financial results for the year ended 31 December 2013 on 26 February 2014 and its annual report on 24 April 2014 and Horizon released its half yearly report on 28 February 2014. Although both companies released March 2014 quarterly activity reports at the end of April 2014

63 Market capitalisation calculated by reference to fully paid shares currently on issue only.

(at or immediately following the announcement of the Merger), there is no reason to conclude that share market values in the period immediately before the announcement of the Merger represented anything other than fully informed, objective market estimates of value.

Analysis of relative contributions of value on the basis of equity market values needs to be treated with some caution. Equity market views on value can shift significantly in short periods of time. This applies particularly in the resources sector, where exploration success, revised views on project life and reserves, movements in commodity prices, price expectations, exchange rate and other factors can result in major changes in equity market views on value in short periods of time. However, changes in these factors should also affect estimates of underlying value. Whilst share prices may be volatile, share market values (for companies with liquid share trading) generally reflect unbiased, market consensus views on value.

The relative sharemarket values of ROC and Horizon have varied in a narrow band over the period prior to announcement. Nonetheless, overall it appears clear that the aggregate interests of ROC and Horizon shareholders in New ROC will be proportionate to sharemarket estimates of the values of the two companies. Accordingly, based on sharemarket values for the two companies, the Merger terms are fair.

8.4 Relative Contributions – Full Underlying Value

The following table summarises the value contributed by ROC and Horizon based on Grant Samuel's estimated full underlying value of each company as set out in Sections 7.3 and 7.4 of this report:

Relative Contribution – Full Underlying Value (US$ million)		
	Grant Samuel Estimates of Value[64]	
	ROC	Horizon
Full Underlying Value Contribution – High	**507**	**721**
Full Underlying Value Contribution – Low	**391**	**561**
Relative Value Contributions – High	41.3%	58.7%
Relative Value Contributions – Low	41.1%	58.9%

Based on fully paid shares currently on issue, ROC shareholders will collectively hold 42.2% of the shares in New ROC. However, on a fully diluted basis[65], this proportion decreases to around 41.6% (and lower if any of Horizon's convertible bonds are converted into Horizon shares prior to the record date for Horizon's Scheme).

Grant Samuel's assessment of the full underlying value of ROC and Horizon suggests that, on a fully diluted basis, ROC is contributing approximately 41% of the underlying value of New ROC.

The majority of the assets of ROC and Horizon can be valued with some confidence. Most of the assets are mature and well understood (e.g. Beibu Gulf, Zhao Dong, Maari/Manaia, Cliff Head and the United Kingdom assets). In other cases, recent acquisitions or contractual terms provide evidence as to value (e.g. ROC's Malaysian assets). On the other hand, there is considerably less certainty regarding the value of Horizon's PNG development assets. The valuation of these assets is critical to an assessment of the Merger terms. Grant Samuel has valued Horizon's PNG development assets in the range $300-370 million.

Horizon's PNG assets are situated in the Foreland Basin in the Western Province of PNG. They are at an early stage of development. The PDL for Horizon's first PNG development (a condensate stripping project for the Stanley Field) was granted on 30 May 2014. The much larger EKT condensate stripping project is less advanced.

64 Underlying value has been estimated after adjusting for options and similar securities on issue. On this basis, ROC shareholders will collectively hold a 41.6% interest in New ROC.

65 That is, after adjusting for options and similar securities on issue.

The material value upside for Horizon's PNG assets is associated with commercialisation of the gas resources at Stanley Field and EKT Fields. Stanley gas could potentially be sold to local mining operations or other local customers. The much larger gas volumes at EKT will require access to an LNG project if they are to be commercialised in the foreseeable future. Horizon has examined various LNG development concepts, generally involving the aggregation of EKT gas with other Foreland Basin gas to provide the feedstock for a medium sized LNG facility at the coast. There are a variety of other gas resources in the Foreland Basin that would potentially be suitable for this purpose. While the timing of any development is uncertain, there are multiple options for the development of Horizon's gas.

Horizon's joint venture partners in the Stanley and EKT fields should be incentivised to commercialise the gas. Osaka Gas and Mitsubishi Corporation are both focussed on gas offtake and Talisman has interests in significant gas fields to the south which could be commercialised in conjunction with EKT. The successful commencement of production by the PNG LNG project should provide assurance to investors, industry participants and potential gas off takers that PNG is an attractive environment for LNG development. Accordingly, while Horizon's plans for an LNG development are currently essentially conceptual, in Grant Samuel's view, there is good reason to be confident that Horizon's gas will ultimately be monetised.

Successful development of the PNG assets, and in particular successful medium term commercialisation of the gas resources on the basis currently contemplated through their utilisation as feedstock for an LNG project, could deliver value materially greater than Grant Samuel's estimate of current values. Such an outcome (with the benefit of hindsight) would mean that the Merger had been extremely advantageous for ROC shareholders. Conversely, an outcome in which large scale gas commercialisation is not achieved or is significantly delayed is also conceivable and would mean that, in retrospect, the Merger was not in the best interests of ROC shareholders.

In this context, a broad range of valuation conclusions could reasonably be reached. Shareholders who take a materially more conservative view than Grant Samuel on the value of Horizon's PNG assets could conclude that the terms of the Merger are not fair to ROC shareholders. Conversely, shareholders with a strongly positive view on Horizon's PNG assets could conclude that the Merger is value accretive for ROC shareholders.

Furthermore, estimates of the underlying value of ROC and Horizon are sensitive to oil price assumptions and judgements about future project potential. Notwithstanding the uncertainties inherent in estimates of the underlying values of ROC and Horizon, it is reasonable to conclude that the collective interest of ROC shareholders in New ROC will be approximately proportionate to the underlying value to be contributed to New ROC.

Accordingly, on the basis of Grant Samuel's estimates of the underlying values of ROC and Horizon, the Merger terms are fair.

8.5 Relative Contributions – Other Parameters

Grant Samuel has also considered the relative contributions of ROC and Horizon to New ROC based on a range of other parameters (i.e. reserves, resources and production). Typically, this review would also have included the contribution of earnings to the merged company. However, in the case of ROC and Horizon, historical earnings are not considered representative of the future earnings of either company and, therefore, not meaningful for an analysis of relative contributions to New ROC.

The following table shows the contribution of reserves, resources and production that ROC and Horizon will make to New ROC relative to the merger terms:

Relative Contributions – Other Parameters				
	ROC	Horizon	Contribution %	
			ROC	Horizon
Merger terms			**42%**	**58%**
Reserves and Resources at 1 January 2014				
2P (proven and probable) (mmboe)	17.4	15.9	52.3%	47.7%
2C (contingent resources) (mmboe)	33.7	79.3	29.8%	70.2%
2P + 2C (total) (mmboe)	51.1	95.2	34.9%	65.1%
2P + 2C (oil and condensate) (mmbbl)	46.9	31.2	60.1%	39.9%
2P + 2C (gas) (bcf)	24.8	385.0	6.1%	93.9%
Production (mmboe)				
Year end 31 December 2013[66] (actual)	2.7	1.2[67]	69.2%	30.8%
Year end 31 December 2014 (projected)	3.2[55]	1.7	65.3%	34.7%

Source: ROC, Horizon and Grant Samuel analysis

This analysis indicates that:

- although ROC is contributing approximately 52% of 2P reserves, it is only contributing around 30% of contingent resources and overall 35% of 2P+2C reserves and resources. In particular, ROC is contributing 60% of liquids reserves and resources, while Horizon is contributing over 90% of gas reserves and resources to New ROC; and
- ROC is contributing around 65% of current production (and therefore revenue) to New ROC. On the other hand, based on current production profiles, ROC's production will decline significantly in the medium term (from around 13,000boepd to around 5,000boepd from 2020) while Horizon's PNG assets represent future growth opportunities for the merged company from around 2019 onwards.

In Grant Samuel's view, the relative contributions on the basis of other parameters broadly reflects the logic of the Merger in that ROC is contributing near term production and earnings while Horizon is contributing near term production and growth plus longer term growth.

8.6 Investment Characteristics

If the Merger is implemented New ROC will have a different growth, risk and earnings profile than a standalone ROC:

- New ROC will be a more growth focussed business, with a series of growth opportunities in PNG, but these growth opportunities also bring risks to which ROC is not currently exposed, including development risks and PNG sovereign risk;
- New ROC will initially have a modest level of debt (pro forma net debt as at 31 December 2013 of around $50 million). In comparison, ROC held net cash at 31 December 2013 of $65 million which provides a buffer against adverse movements in oil prices and represents a significant (and certain) component of the overall value of ROC (18 % of market capitalisation prior to the announcement of the Merger). The shift in the company's capital structure theoretically increases the level of financial risk but this level of gearing (around 10%) is not significant having regard to the market value, asset base and operating cash flows of New ROC. Moreover, it is unlikely that ROC on a standalone basis would have continued to hold this level of cash for any length of time, given investor expectations that it should be used to fund growth opportunities (such as the D35/D21/J4 PSC) or returned to shareholders;
- New ROC's share of the funding required for the PNG developments will be substantial. However, it should be manageable given the free cash flows expected to be generated by the producing assets of New ROC (assuming oil prices around current levels); and

66 Production from the Beibu Gulf Joint Venture (in which both ROC and Horizon have an interest) only commenced in March 2013.

67 Production for Horizon in 2013 was low as the Maari/Manaia Oil Fields in New Zealand were offline for around seven months due to planned upgrade and repair work.

- pro forma forecasts of earnings or free cash flows have not been prepared. However, it is likely that, in the short term, free cash flow per share for New ROC will be lower than for ROC on a standalone basis given the need to fund the developments in PNG and because earnings from the PNG assets will not commence for a number of years. In the medium term, the Merger should result in strong growth in earnings and free cash flows (assuming the successful development of the PNG assets).

In the short term, these changes in the characteristics of New ROC should have a broadly neutral or possibly marginally positive impact on value, with longer term growth in earnings and free cash flows essentially offsetting shorter term development costs and risks. The sharemarket's response to the announcement of the Merger, with shares in both ROC and Horizon trading higher, suggest that market participants have a similar view. However, shareholders with a particular focus on short term cash flows, little appetite for development risks or a limited interest in long term exposure to oil and gas assets, could take a different view, which might lead them to a conclusion that the Merger is not in their best interests.

8.7 Benefits of the Merger

The Merger will result in a company significantly different from ROC on a standalone basis. In particular, New ROC will:

- be a substantially larger company, with a broader shareholder base and a pro forma market capitalisation approaching A$900 million (based on share prices as at 13 June 2014). It will become one of the largest mid cap ASX listed upstream oil and gas companies and will be Asian focussed;
- become a member of the S&P/ASX 200 Index (ROC is currently a member of the S&P/ASX 300 Index while Horizon is a member of the S&P/ASX 200 Index);
- have a strong balance sheet, with pro forma net debt of around $50 million as at 31 December 2013 and strong cash flows from producing assets in China, New Zealand, Malaysia, Australia and the United Kingdom;
- own a portfolio of assets across the full spectrum of upstream oil and gas activities and with greater geographic diversity, although focussed on the Asian region. New ROC's greater geographic diversification may reduce its risk profile relative to that of ROC on a standalone basis. However, the sovereign risk issues associated with Horizon's PNG assets may offset this benefit (although this risk should already be reflected in the market values of Horizon);
- have a more attractive development pipeline than ROC on a standalone basis. The majority of ROC's assets are mature or in decline and ROC's 48% interest in BC Petroleum represents no more than reimbursement of capital expenditure already incurred. Accordingly, there are only limited growth options in ROC's existing asset portfolio (although it recently farmed into the D35/D21/J4 PSC offshore Malaysia that offers upside potential). Horizon's PNG development assets provide an opportunity to participate in the development of the Stanley liquid stripping project, the larger and earlier stage EKT liquids stripping project and a large scale gas commercialisation project;
- over time have access to debt markets on better terms than ROC on a standalone basis, given its larger size, diversified asset base and free cash flows (subject to PNG commitments). Given ROC's current net cash position, debt capacity has not been an issue. However, over the next two years ROC faces significant commitments for Block 09/05 and the first part of the D35/D21/J4 PSC redevelopment project and it may need to access its undrawn debt facility (notwithstanding that it is likely to recover its investment in BC Petroleum in that period);
- be able to consider larger (and potentially riskier) acquisitions and development opportunities, providing a broader range of growth options than ROC can prudently contemplate on a standalone basis (although its commitment to PNG may mean that such prospects are not pursued initially); and
- have a broader management capability than is available to ROC on a standalone basis (although integration of management teams is not without risk).

While merger synergies are not expected to be material, it is likely that some corporate costs reductions will be achieved. These cost reductions could be in the order of $4-5 million per annum. Furthermore, no negative taxation consequences for the company are expected from implementation of the Merger (nor are there taxation consequences for ROC shareholders).

In Grant Samuel's view, none of the likely benefits of the Merger is by itself compelling and many will only be realised over time. To some extent, the benefits of the Merger essentially constitute growth options not available to ROC on a standalone basis. The extent and timing of New ROC's realisation of value from these options is uncertain and will depend on future circumstances and management decisions.

8.8 Share Trading Post the Merger Announcement

There are good reasons to expect a positive re-rating of New ROC relative to ROC on a standalone basis. In particular:

- New ROC's increased market capitalisation, index inclusion and greater share trading liquidity should increase New ROC's attractiveness to institutional investors;
- New ROC's asset portfolio will provide more growth options than available to ROC on a standalone basis. More generally, its greater size and enhanced access to capital will allow it to consider growth opportunities not available to ROC; and
- it is expected that some cost synergies will be realised (although these will not be material).

In the ordinary course, it is difficult to quantify the possible extent of any re-rating benefits. In the case of the Merger, however, share trading in ROC (and to a lesser extent Horizon) since the announcement of the Merger does provide some insight into the possible re-rating benefits.

Since the announcement of the Merger, ROC's share price has increased by around 21% (based on ROC's closing share prices on 23 April 2014 and 13 June 2014). Relative to an undisturbed share price on 22 April 2014 of A$0.335[68], Horizon's share price has increased by around 13%. On this basis, the growth in the combined market capitalisation of the two companies is of the order of 18% over the period. There are a number of factors that may have contributed to the strong share price performance of ROC and Horizon. However, it appears reasonable to conclude that this outperformance, at least in part, reflects market anticipation of the re-rating benefits of the Merger. Overall, in Grant Samuel's view, ROC's share price performance since the announcement of the Merger represents a strong market endorsement of the Merger. ROC (and Horizon) shareholders would stand to lose the recent share price appreciation if the Merger did not proceed.

8.9 Control Issues

Following implementation of the Merger former ROC shareholders will collectively hold around 42% of New ROC and former Horizon shareholders will collectively hold around 58%. ROC's largest existing substantial shareholder is Allan Gray, with a declared relevant interest of around 20% (most of which is managed on behalf of investors). Based on substantial shareholder notices at 13 June 2014, the major shareholders in New ROC are expected to be as follows:

New ROC – Major Shareholders

Shareholder	Number of Shares	Percentage[69]
Austral-Asia	231,459,678	14.11%
Allan Gray	137,906,663	8.41%
Commonwealth Bank of Australia	99,761,461	6.08%
Tribeca Investment Partners Pty Limited	49,512,907	3.02%

Source: Grant Samuel analysis

The Merger has the impact of diluting the shareholding of Allan Gray and introduces a new private

[68] Horizon's share price increased by around 10% on 23 April 2014.

[69] Calculated based on 1,640,201,804 ordinary shares.

strategic investor (Austral-Asia, a subsidiary of the privately owned Singaporean headquartered IMC Group). Mr Gerrit de Nys, a director associated with Austral-Asia, is expected to be a member of the board of New ROC.

New ROC's share register will remain relatively widely distributed with no controlling shareholder or shareholder bloc. Arguably, the dilution of Allan Gray's shareholding will mean that New ROC's register is more open than ROC's existing register. However, Austral-Asia will become the largest shareholder with a 14% interest.

ROC shareholders will not give up the opportunity to realise a full premium for control at some time in the future. There will still be an opportunity to realise a full premium through a subsequent change of control transaction involving New ROC. On one view, the prospects of New ROC receiving a change of control proposal should be greater than for ROC on a standalone basis. The PNG assets being contributed by Horizon are potentially of material scale and considerable strategic value in the context of the fragmented gas resources holdings in the PNG Foreland Basin. In this context, New ROC may ultimately have considerable corporate appeal.

8.10 Other Disadvantages

The other disadvantages of the Merger for ROC shareholders include:

- New ROC will have a lower proportion of liquids in the overall hydrocarbon mix (although this is reflected in Grant Samuel's estimates of underlying value and should be reflected in sharemarket values of ROC and Horizon);
- ROC shareholders' proportionate exposure to 2P reserves will decline. On other hand, ROC shareholders will enjoy a substantial increase in their exposure to 2C resources;
- ROC shareholders will have a more highly geared exposure (both positive and negative) to movements in the oil price, as New ROC will have net debt compared to ROC's net cash;
- a significant part of Horizon's value is contributed by assets in PNG. The sovereign risk associated with these assets should be reflected in Horizon's market value and has been taken into account in Grant Samuel's valuation of Horizon. Nevertheless, following the Merger ROC shareholders will be exposed to a greater degree of sovereign risk than is currently the case;
- ROC shareholders will be exposed to exploration and development risk to a greater degree than in ROC on a standalone basis. In Grant Samuel's view the additional risk will be offset by the growth potential contributed by the Horizon assets. In any event, the additional risk has been taken into account in Grant Samuel's valuation analysis and should be reflected in the sharemarket value of Horizon; and
- transaction costs related to the Merger are estimated to total around $8.3 million, of which ROC shareholders will effectively fund 42% ($3.5 million). Of these, approximately $2 million will be incurred by ROC on a standalone basis if the Merger does not proceed. The incremental costs to be funded by ROC shareholders if the Merger is implemented ($1.5 million) are not material having regard to the values of ROC and Horizon.

There are implementation risks in any merger but in this case the complementary nature of the ROC and Horizon businesses should reduce such risk.

8.11 Other Matters

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

It is a matter for individual shareholders as to whether to buy, hold or sell shares in ROC, or Horizon or New ROC. These are investment decisions upon which Grant Samuel does not offer an opinion. Shareholders should consult their own professional adviser in this regard.

9 Qualifications, Declarations and Consents

9.1 Qualifications

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

The persons responsible for preparing this report on behalf of Grant Samuel are Stephen Cooper BCom (Hons) ACA(SA) ACMA and Caleena Stilwell BBus FCA F Fin. Each has a significant number of years of experience in relevant corporate advisory matters. Tina de Young BCom CFA, Matt Leroux MEng MBA and Danielle Rodgers BEcon(Hons) BComm assisted in the preparation of the report. Each of the above persons is a representative of Grant Samuel pursuant to its Australian Financial Services Licence under Part 7.6 of the Corporations Act.

9.2 Disclaimers

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

Grant Samuel has had no involvement in ROC's due diligence investigation in relation to Horizon and does not accept any responsibility for the completeness or reliability of the process which is the responsibility of ROC.

9.3 Independence

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

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

Grant Samuel will receive a fixed fee of $275,000 for the preparation of this report. This fee is not contingent on the conclusions reached or the outcome of the Merger. Grant Samuel's out of pocket expenses in relation to the preparation of the report will be reimbursed. Grant Samuel will receive no other benefit for the preparation of this report.

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

9.4 Declarations

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

Advance drafts of this report were provided to ROC and its advisers. Advance drafts of Sections 1-6 of this report were also provided to Horizon and Sections 4.6.4 and 4.6.8 of this report were provided to PETRONAS. Certain changes were made to the drafting of the report as a result of the circulation of the draft report. There was no alteration to the methodology, evaluation or conclusions as a result of issuing the drafts.

9.5 Consents

Grant Samuel consents to the lodging of this report with the ASX for public release. Neither the whole nor any part of this report nor any reference thereto may be included in any other document without the prior written consent of Grant Samuel as to the form and context in which it appears.

9.6 Other

The accompanying letter dated 15 June 2014 and the Appendices form part of this report.

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

GRANT SAMUEL & ASSOCIATES PTY LIMITED
15 June 2014

Grant Samuel & Associates

Appendix 1

Glossary of Technical Terms

The following terms used in this report have the meanings set out below:

Glossary of Technical Terms	
Abbreviation	**Description**
1P	Proved reserves. There is at least a 90% probability that the quantities recovered will equal or exceed this estimate
2P	Proved and probable reserves. There is at least a 50% probability that the quantities recovered will equal or exceed this estimate
3P	Proved, probable and possible reserves. There is at least a 10% probability that the quantities recovered will equal or exceed this estimate
1C	Low estimate scenario of contingent resources. There is at least a 90% probability that the quantities recovered will equal or exceed this estimate
2C	Best estimate scenario of contingent resource. There is at least a 50% probability that the quantities recovered will equal or exceed this estimate
3C	High estimate scenario of contingent resource. There is at least a 50% probability that the quantities recovered will equal or exceed this estimate
Appraisal well	Well drilled to determine the size of an oil or gas discovery
Condensate	Hydrocarbons which are typically gaseous under reservoir conditions but which condensate to form liquids when they rise to the surface due to changes in pressure and temperature
Contingent resources	Those quantities estimated, at a given date, to be potentially recoverable from known accumulations by application of development projects but not yet considered to be commercially recoverable due to one or more contingencies (e.g. commerciality of the project has not been clearly assessed, there is no market for the product or the technology required to extract the product is under development)
Crude oil	Unrefined liquid petroleum. Crude oils range from very light (high in gasoline) to very heavy (high in residual oils). Sour crude is high in sulphur content whereas sweet crude is low in sulphur and therefore often more valuable
Development well	A well drilled to enable production from a known oil or gas reservoir
Energy measures	▪ Joule – primary measure of energy in the metric system ▪ Gigajoule (GJ) – a gigajoule equals one billion joules ▪ Terajoule (TJ) – a terajoule is equal to 1,000 gigajoules ▪ Petajoule (PJ) – a petajoule is equal to one million gigajoules ▪ Petajoules equivalent (PJe) – an energy measurement representing the equivalent energy in different products so the amount of energy contained in those products can be compared
Exploration well	A well drilled to identify a new reservoir of oil or gas
Farm in	The process whereby a party acquires an interest in an oil, gas or mineral interest by paying a sum of money and/or committing to spend money to perform a specific activity in relation to the interest.
Farm out	The assignment of part or all of an oil, gas or mineral interest to a third party for a sum of money and/or a commitment to spend money to perform a specific activity in relation to the interest.
FEED	Front end engineering and design. Conceptual design prior to detailed design
FID	Final investment decision
Gas measures	▪ Cubic feet (cf) – primary unit for the measurement of natural gas ▪ Thousand cubic feet (mcf) – one thousand cubic feet of natural gas ▪ Million cubic feet (mmcf) – one million cubic feet of natural gas ▪ Billion cubic feet (bcf) – one billion cubic feet of natural gas where a billion is defined as 10^9. On average 1bcf of sales gas = 1.055PJ ▪ Trillion cubic feet (tcf) – one trillion cubic feet of natural gas where a trillion is defined as 10^{12}. ▪ mscfd – one thousand cubic feet of natural gas per day ▪ mmscfd – one million standard cubic feet of natural gas per day ▪ bscfd – one billion standard cubic feet of natural gas per day
Back in	The right of a government or its nominee to acquire a percentage interest in a project either by way of a cash payment or a carry (e.g. PNG has a right to acquire a participating interest of up to 22.5% of a petroleum project)
Hydrocarbons	Solid, liquid or gas compounds of the elements hydrogen and carbon

Glossary of Technical Terms	
Abbreviation	**Description**
Hydrocarbon measures:	▪ boe – barrel of oil equivalent (equivalent to approximately 6,000bcf of gas) ▪ bbls – barrels = an international measure of oil production. 1 barrel = approximately 159 litres ▪ bpd – barrels of oil per day ▪ btu – British thermal unit (equivalent to 1,055 joules) ▪ kbbls – Kilo barrels = 1,000 barrels ▪ mmbbls – million barrels ▪ mmboe – million barrels of oil equivalent ▪ mmbpd – million barrels of oil per day ▪ mmBtu – million Btu ▪ kt – Kilo tonnes = 1,000 tonnes ▪ mt – Million tonnes ▪ mtpa – Million tonnes per annum
LNG	Liquefied natural gas. Natural gas that has been liquefied by refrigeration for storage or transport. Generally comprises mainly methane
Prospective resources	Those volumes estimated, as at a given date, as potentially recoverable from undiscovered accumulations
Reserves	Those quantities anticipated to be commercially recoverable by application of development projects to know 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 categorised in accordance with the level of certainty associated with the estimates
Sales gas	Natural gas that has been processed in gas processing facilities and meets the required specifications under gas sales contracts
Seismic survey	A survey used to gain an understanding of rock formation beneath the earth's surface

Appendix 2

Independent Technical Specialists Report

RISC Operations Pty Limited

INDEPENDENT TECHNICAL SPECIALIST REPORT ON THE PETROLEUM PROPERTIES OF ROC OIL COMPANY LIMITED AND HORIZON OIL LIMITED FOR GRANT SAMUEL & ASSOCIATES PTY LTD

Strictly Confidential

June 2014

DECISIONS WITH CONFIDENCE

TABLE OF CONTENTS

1. SUMMARY 1
1.1. Overview 1
1.2. Exploration Valuation 4
2. TERMS OF REFERENCE 5
3. BASIS OF ASSESSMENT 6
4. AUSTRALIA 8
4.1. Cliff Head 8
4.1.1. Field Description 8
4.1.2. Production and Cost forecast 10
4.2. Exploration 11
5. UNITED KINGDOM 13
5.1. Blane and Enoch Field Description 13
5.2. Blane and Enoch Production and Cost forecast 15
5.3. Reserves and Contingent Resources 17
5.4. J1 Discovery - Block 16/13e (15% Roc) 18
5.5. Exploration 19
6. NEW ZEALAND 20
6.1. Maari/Manaia/Mangehewa 20
6.1.1. Field Description 20
6.1.2. Production and Cost Forecast 23
6.2. Exploration 26
7. CHINA PROPERTIES 30
7.1. Beibu GULF 30
7.1.1. Field Description 31
7.1.2. Production and Cost Forecasts 36
7.1.3. 12-8 East Proposed Development 37
7.1.4. Exploration 38
7.2. Bohai Bay 40
7.2.1. Field Description 42
7.2.2. Production and Cost forecast 45
7.2.3. Exploration 49
7.2.4. Chenghai Block Development 50
8. PAPUA NEW GUINEA 52
8.1. PRL 4 52
8.1.1. Stanley Field Description 52
8.1.2. Production and Cost forecast 54
8.1.3. PRL 4 Exploration 57
8.2. PRL 21 57
8.2.1. Elevala and Ketu Field Description 57
8.2.2. Production and Cost forecast 60
8.2.3. Gas Export (via Mid-scale LNG) 63
8.3. Exploration 65
8.3.1. PRL 21 65
8.3.2. PPL259 66
8.3.3. PPL 372 and PPL 373 69
8.3.4. PPL 430 69

8.3.5. PNG Exploration Value Summary 70
9. MALAYSIA 71
9.1. D35/ J4/ D21 71
9.1.1. Field description 71
9.1.2. Production forecast 72
9.1.3. Capital and operating cost forecast 76
9.2. Balai Cluster 78
9.3. Exploration 78
10. MYANMAR 80
11. DECLARATIONS 82
11.1. Qualifications 82
11.2. Reliance 82
11.3. Valmin Code 82
11.4. Petroleum Resources Management System 83
11.5. Report to be presented in its entirety 83
11.6. Independence 83
11.7. Limitations 83
11.8. Consent 84
12. LIST OF TERMS 85

LIST OF FIGURES

Figure 1-1 Location Map Roc Oil and Gas Properties 1
Figure 1-2 Location Map Horizon Oil and Gas Properties 2
Figure 4-1 Location Map - Cliff Head 8
Figure 4-2 Top Reservoir Map - Cliff Head....9
Figure 4-3 Gross 2P Production Forecast - Cliff Head....10
Figure 4-4 Gross Operating Cost Forecast - Cliff Head 10
Figure 4-5 Mentelle depth maps post and pre-tilt 12
Figure 5-1 Location Map - Blane....13
Figure 5-2 Location Map - Enoch Field and J1 discovery....14
Figure 5-3 Gross 2P Oil Production Forecast - Blane 15
Figure 5-4 Gross 2P Production Forecast - Enoch 15
Figure 5-5 Gross Operating Cost Forecast - Blane....16
Figure 5-6 Gross Operating Cost Forecast - Enoch 17
Figure 5-7 Field Outline - J1 18
Figure 6-1 Maari and Manaia Field Location 20
Figure 6-2 Maari Manaia Structural Section (from Horizon)....21
Figure 6-3 Maari Moki Depth Map 22
Figure 6-4 Gross 2P Oil Production Forecast - Maari and Manaia 24
Figure 6-5 Gross Capital Budget - Maari and Manaia Fields 25
Figure 6-6 Gross Operating Cost Budget - Maari and Manaia Fields 26
Figure 6-7 Whio Prospect M2A and Moki Depth Maps....27
Figure 6-8 Maari 2P + Best Estimate Gross Production Forecast - Whio Prospect 28
Figure 6-9 Gross Capex and Opex - Whio Prospect....28
Figure 7-1 Location Map – Beibu Block 22-12....30
Figure 7-2 Well locations and schematic North, South and “Sliver” Block Field Areas....32
Figure 7-3 Structural relationship of WZ 6-12 South, “Sliver” and North Fields....33
Figure 7-4 Final well tied top J2 reservoir depth structure map (post development drilling) 34
Figure 7-5 WZ12-8 East reservoir depth structure maps and field limits....35
Figure 7-6 Gross 2P Oil Production Forecast - Beibu WZ6-12 N, 6-12 S and 12-8 W 36
Figure 7-7 Gross 2P+2C Gross Production Forecast – 2P Plus WZ12-8E 37
Figure 7-8 2P+2C Cost Forecast – 2P Plus WZ12-8E....38
Figure 7-9 Beibu Gulf Exploration Prospects (subject to approval of license boundary extension shown in dotted red line)....38
Figure 7-10 Gross Production Forecast: 2P Plus 2C Plus Prospect-3....39
Figure 7-11 Cost Forecast 2P + 2C + Prospect-3....40
Figure 7-12 Location Map – Bohai Bay 41
Figure 7-13 Zhao Dong and C4 oil accumulation map....42
Figure 7-14 Schematic cross-section showing typical plays 43
Figure 7-15 2P Gross Oil Production Forecast - C&D Fields 45
Figure 7-16 2P Gross Oil Production Forecast - C-4 Field....46
Figure 7-17 2P+2C Gross Oil Production Forecast - All Fields 47
Figure 7-18 2P+2C Gross Gas Sales Forecast - All Fields....47
Figure 7-19 Gross 2P Costs - Bohai Bay 48
Figure 7-20 Gross 2P+2C Costs - Bohai Bay....49
Figure 7-21 Map showing Zhaghai and Chenghai Blocks, Zhao Dong wells and Discoveries....50
Figure 8-1 Horizon PNG Interest Location Map....52
Figure 8-2 Stanley 2P Liquids Stripping Gross Cost Forecast - RISC Estimate 55
Figure 8-3 Stanley 2P Gross Production Forecast – Condensate stripping only....56
Figure 8-4 2P+2C Gross Production Forecast – Condensate stripping and gas export 57

Figure 8-5 Elevala Field Elevala Reservoir Depth Structure Map 58
Figure 8-6 Ketu Field Elevala Reservoir Depth Structure Map 59
Figure 8-7 Elevela-Ketu Gross Cost Forecast - Liquids Stripping Only 1/1/2018 Start Up...............................61
Figure 8-8 Elevela-Ketu Gross Cost Forecast - Liquids Stripping Only 1/1/2019 Start Up................................62
Figure 8-9 Elevala-Ketu 2C Gross Production Forecast – Condensate stripping only 62
Figure 8-10 Elevala-Ketu 2C Gross Production Forecast – Condensate stripping and gas export 63
Figure 8-11 Horizon PNG Exploration Acreage..65
Figure 8-12 PPL 259 Block Location and Prospects 67
Figure 8-13 PPL 259 Nama Prospect Toro Depth Structure Map 68
Figure 9-1 Location Map – Malaysian Fields, offshore Sarawak 71
Figure 9-2 Gross oil production forecast, D35/J4/D21- Roc estimates 73
Figure 9-3 D35/D21/J4 Gross Capex Phasing – Roc estimates 77
Figure 9-4 D35/D21/J4 Gross Opex Phasing – Roc estimates 78
Figure 10-1 Myanmar Block M7 Location Map 80
Figure 10-2 M7 Block Prospectivity 81

LIST OF TABLES

Table 1-1 Roc Gross and Working Interest 2P Reserves at 1/1/2014 2
Table 1-2 Roc Gross and Working Interest 2C Contingent Resources at 1/1/2014 3
Table 1-3 Horizon Gross and Working Interest 2P Reserves at 1/1/2014.....3
Table 1-4 Horizon Gross and Working Interest 2C Contingent Resources at 1/1/2014.....3
Table 1-5 Exploration Valuation - Horizon Net Working Interest.....4
Table 1-6 Exploration Valuation - Roc Net Working Interest 4
Table 4-1 Gross Reserve Estimate at 1 January 2014 - Cliff Head 11
Table 4-2 Gross 2C Contingent Resource Estimate at 1 January 2014 - Cliff Head 11
Table 4-3 Gross Best Estimate Prospective Resources as at 1 January 2014 - Mentelle Prospect 12
Table 5-1 Gross Reserves as at 1 January 2014 - Blane and Enoch 17
Table 5-2 Gross 2C Contingent Resources at 1 January 2014 - Blane and Enoch 18
Table 5-3 2C Gross Contingent Resources Estimate at 1 January 2014 - 16/13e J1 19
Table 6-1 Maari and Manaia Field STOIIP Estimates 23
Table 6-2 Gross Reserves as at 1 January 2014 - Maari and Manaia Fields 23
Table 6-3 Gross 2C Contingent Resources as at 1 January, 2014 - Maari M2A.....23
Table 6-4 Gross Oil Production Forecast - No Benefit from Water Injection at Maari Moki Upper 24
Table 7-1 Discovered STOIIP as at 1 January 2014 - Beibu Gulf 31
Table 7-2 Gross Reserves as at 1 January 2014 - Beibu Gulf 32
Table 7-3 Gross 2C Contingent Resources as at 1 January 2014 - WZ12-8E RISC Estimate 32
Table 7-4 Gross 2P Cost Forecast - Beibu WZ6-12, 6-12 S and 12-8 W.....37
Table 7-5 Beibu Gulf Exploration Fair Market Value - Net Horizon and Roc Working Interest.....40
Table 7-6 STOIIP as at 1 January 2014 - Bohai Bay 44
Table 7-7 Gross Reserves as at 1 January 2014 - Bohai Bay 44
Table 7-8 Gross 2C Contingent Resources as at 1 January 2014 - Bohai Bay 44
Table 7-9 2P Gross Sales Gas Production Forecast - C&D Fields 45
Table 7-10 2P Gross Gas Production Forecast - C-4 Field.....46
Table 8-1 Stanley Field Gross Reserves and Resources as at 30 June 2012 53
Table 8-2 Stanley Gross Capital and Operating Costs as at 1.1.2014 - RISC estimate.....55
Table 8-3 Elevala and Ketu Gross 2C Contingent Resource Estimates as at 1 January 2014 59
Table 8-4 Elevala-Ketu Gross Capital and Operating Costs - RISC estimate 61
Table 8-5 Gas Export Infrastructure Gross Costs - RISC Estimate.....64
Table 8-6 Tingu Toro Gross Best Estimate Prospective Resources as at 1 January 2014.....66
Table 8-7 Nama Prospect Gross Best Estimate Prospective Resources as at 1 January 2014 68
Table 8-8 PNG Exploration Fair Market Value - Net Horizon Working Interest 70
Table 9-1 D35/J4/D21 further development stages.....72
Table 9-2 D35/J4/D21 Gross Reserves and Resources - Roc estimates as at 1 January 2014.....74
Table 9-3 D35/D21/J4 Gross Capex Summary – Roc estimates 77
Table 9-4 Gross Abandonment Cost Summary – Roc estimates 77
Table 9-5 Malaysia D35 Exploration Fair Market Value - Net Roc Working Interest 79
Table 10-1 Myanmar M7 Block Exploration Fair Market Value - Net Roc Working Interest.....81

1. SUMMARY

1.1. OVERVIEW

The document comprises the Independent Technical Specialists Report by RISC Operations Pty Ltd (RISC) to assist the Independent Expert Grant Samuel & Associates Pty Ltd (Grant Samuel) in the preparation of an Independent Expert's Report to the Directors of Roc Oil Company Limited (Roc) on the proposed merger of Roc and Horizon Oil 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.

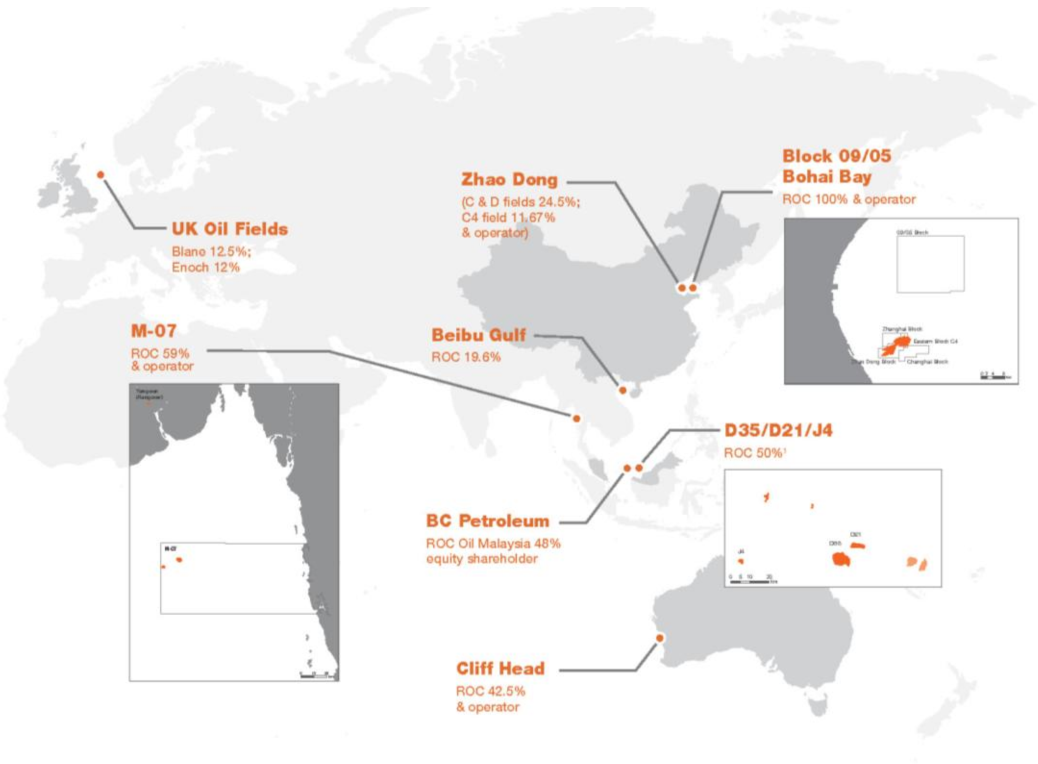


Figure 1-1 Location Map Roc Oil and Gas Properties

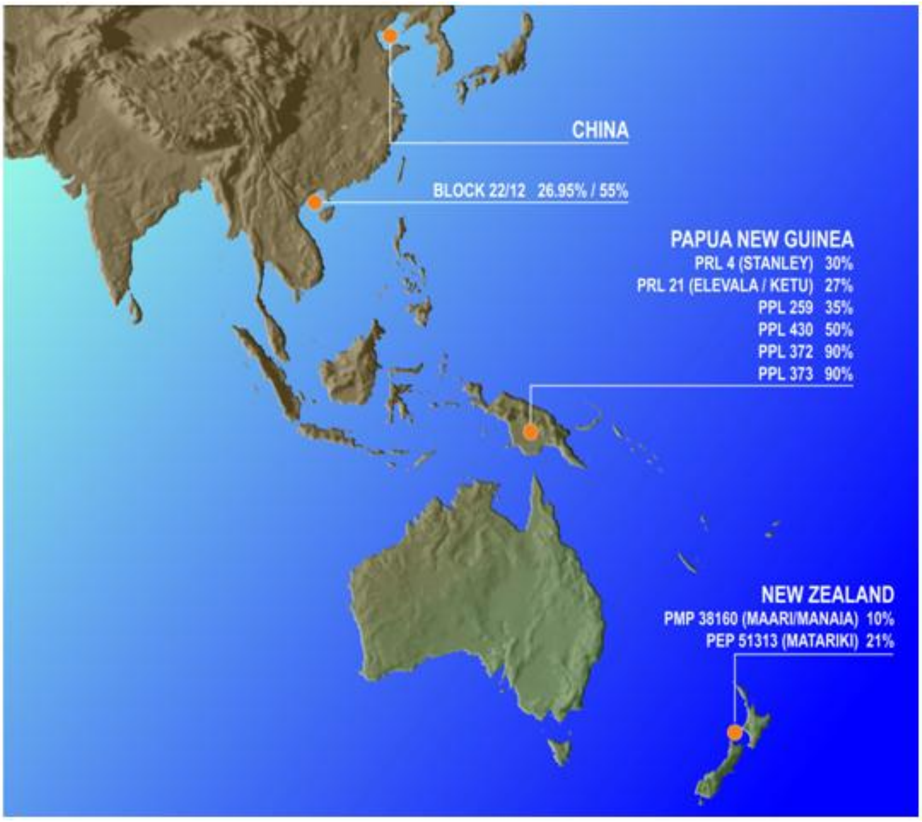


Figure 1-2 Location Map Horizon Oil and Gas Properties

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	372.1
Total	**63.3**	**1378.0**		**20.2**	**372.1**
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 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 and Horizons 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

Grant Samuel has appointed RISC Operations Pty Ltd ("RISC") to provide technical advice to Grant Samuel in relation to the Assignment (the "Subsidiary Assignment").

The purpose of the Subsidiary Assignment is for RISC to provide Grant Samuel with advice in relation to the technical judgments required to complete the Assignment. In particular, RISC is to prepare or, if already available, review estimates of reserves and resources, capital costs, production profiles and operating costs for the producing and development operations of Roc and Horizon and advise Grant Samuel as to whether these assumptions are reasonable for valuation purposes. Grant Samuel may wish to consider a number of development / production scenarios in valuing each of the assets of Roc and Horizon. These scenarios will vary depending upon the specific issues relating to each asset but may be based on extensions to current reserves and/or the potential for variations in future production rates. RISC and Grant Samuel will work together to jointly specify and define the valuation scenarios for each relevant asset. In respect of each valuation scenario, RISC will provide to Grant Samuel the input parameters for Grant Samuel's financial modelling. These parameters will typically consist of production profiles and annual estimates of capital and operating costs. In addition, RISC will review the portfolio of exploration interests of both Roc and Horizon and prepare valuations of those interests.

Grant Samuel expects that the work to be performed by RISC will need to comply with the requirements of the Valmin Code, as appropriate for the Subsidiary Assignment. RISC will be required to prepare a technical specialist's report, setting out the scope of its engagement, the nature of the work performed, a description of the assets and their planned development, and RISC's conclusions as to the technical assumptions regarding reserves, capital costs, production profiles, and operating costs for each of the valuation scenarios. In addition, the report will need to set out RISC's estimates of value for the exploration interests of Horizon and Roc. The technical specialist's report will be appended to Grant Samuel's report.

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.

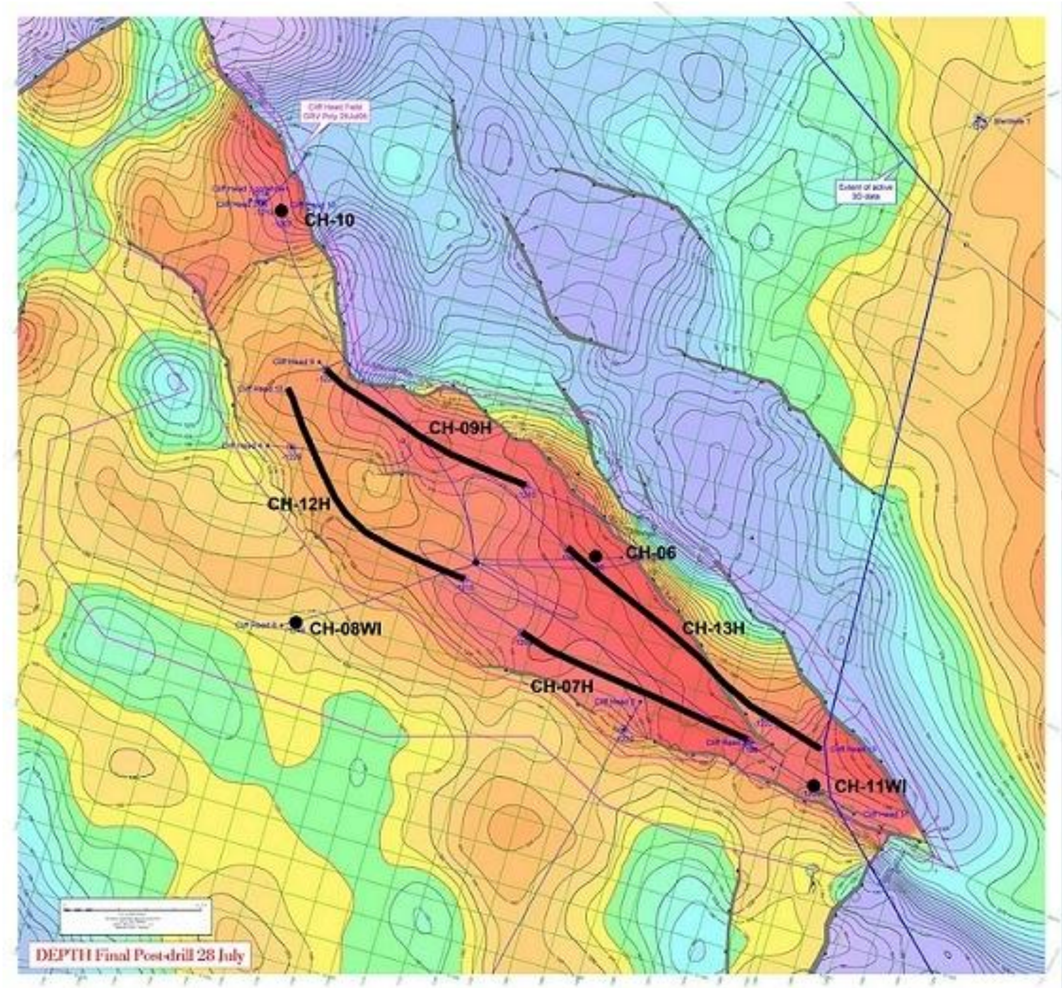


Figure 4-2 Top Reservoir Map - Cliff Head

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.

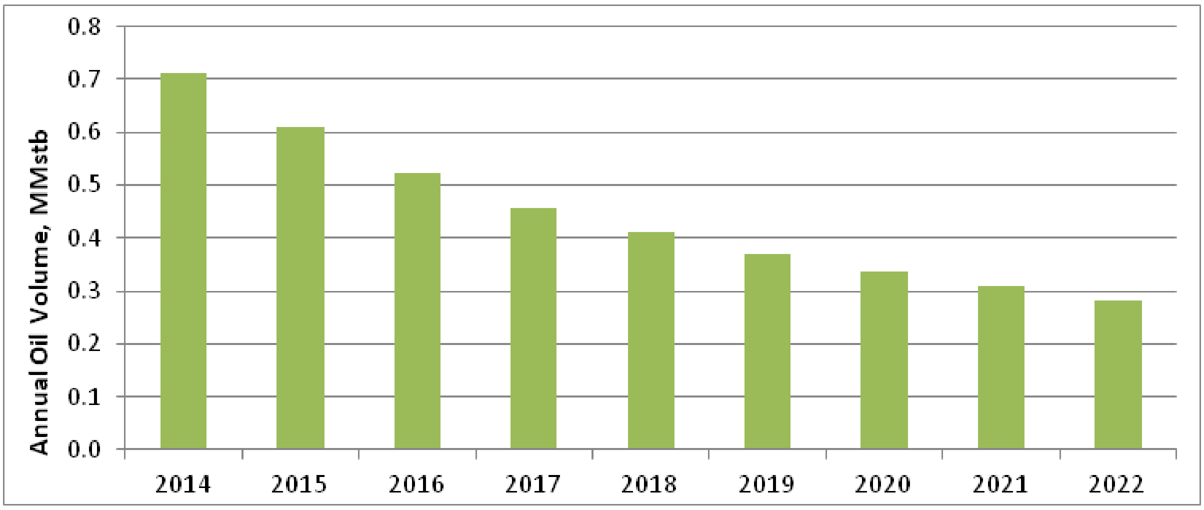


Figure 4-3 Gross 2P Production Forecast - Cliff Head

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

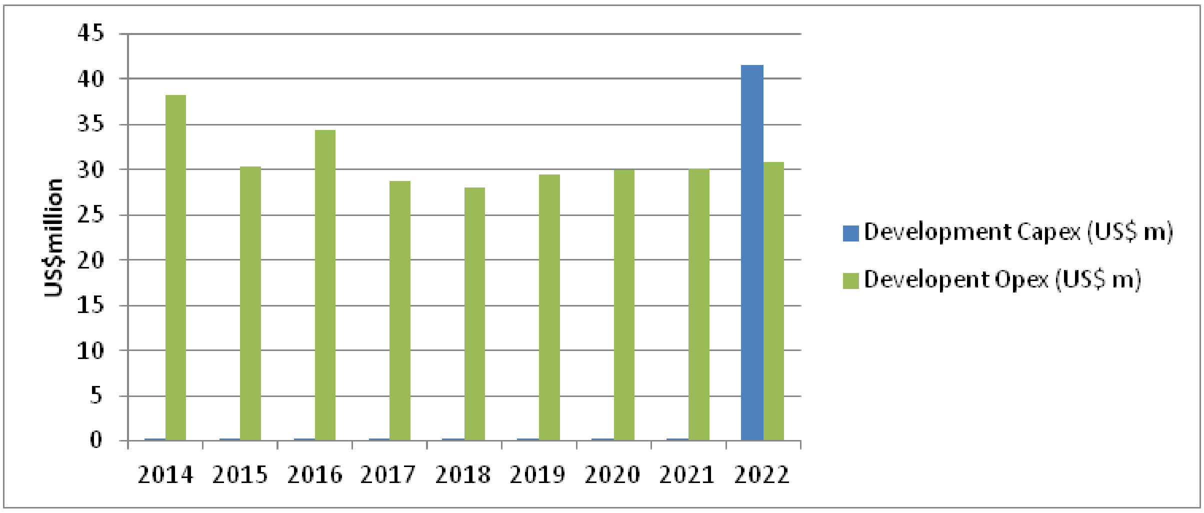


Figure 4-4 Gross Operating Cost Forecast - Cliff Head

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.

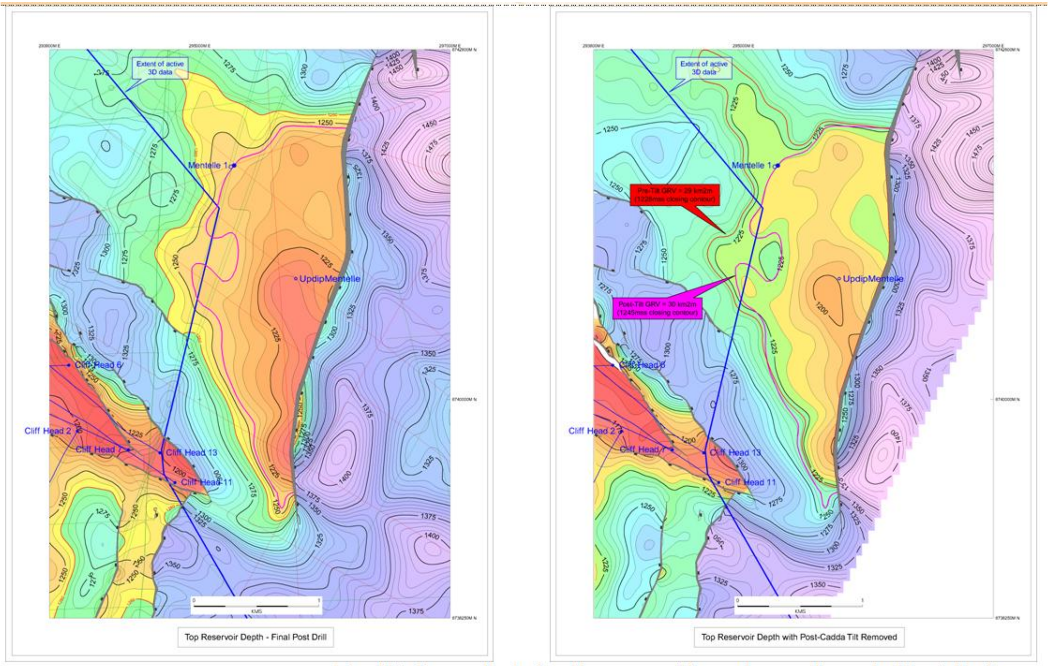


Figure 4-5 Mentelle depth maps post and pre-tilt

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.

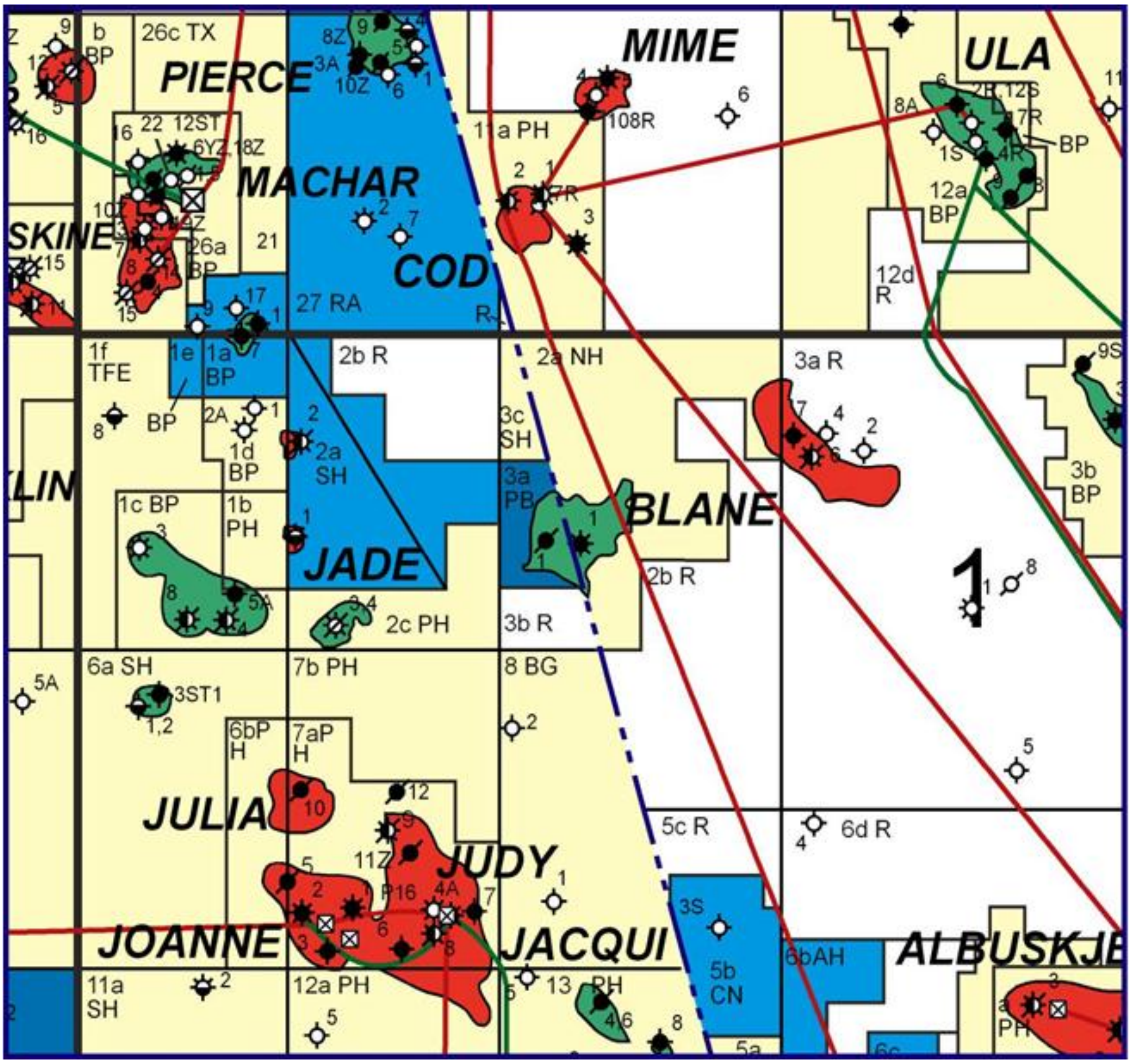


Figure 5-1 Location Map - Blane

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.

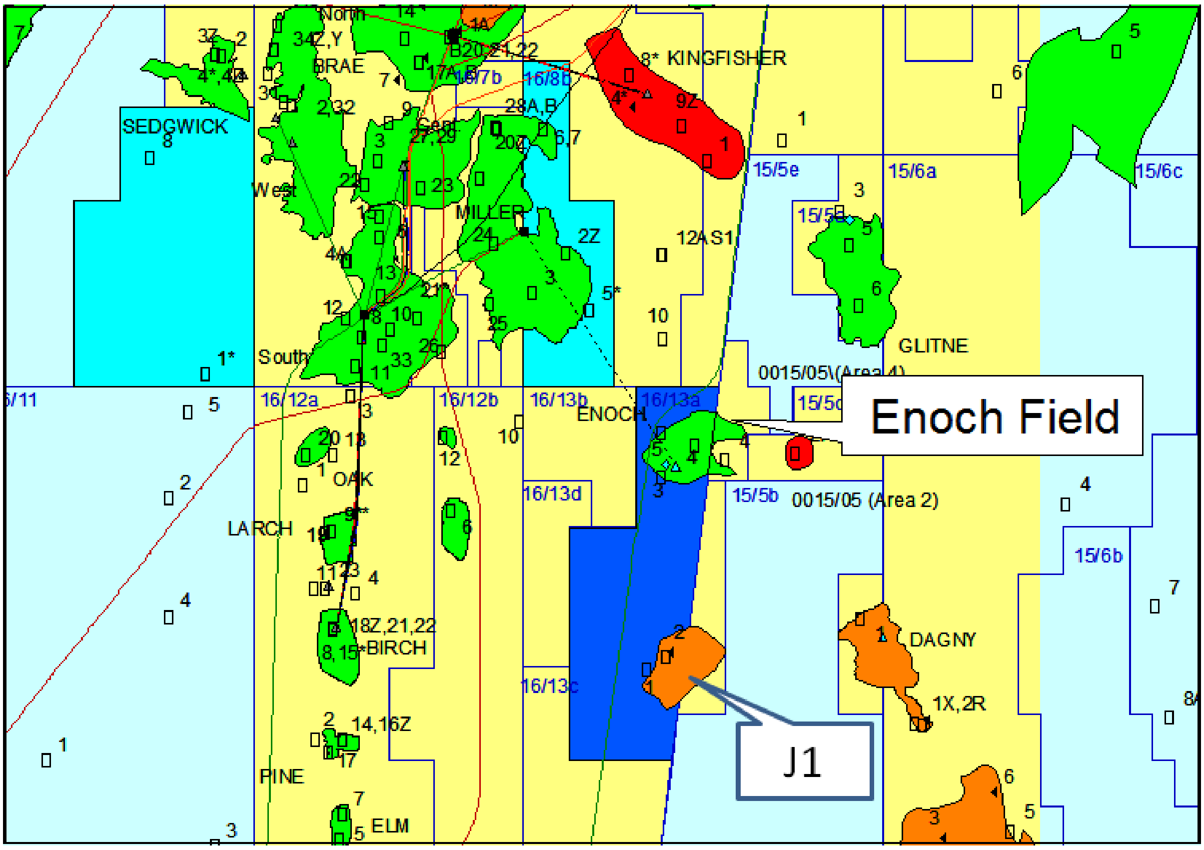


Figure 5-2 Location Map - Enoch Field and J1 discovery

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.

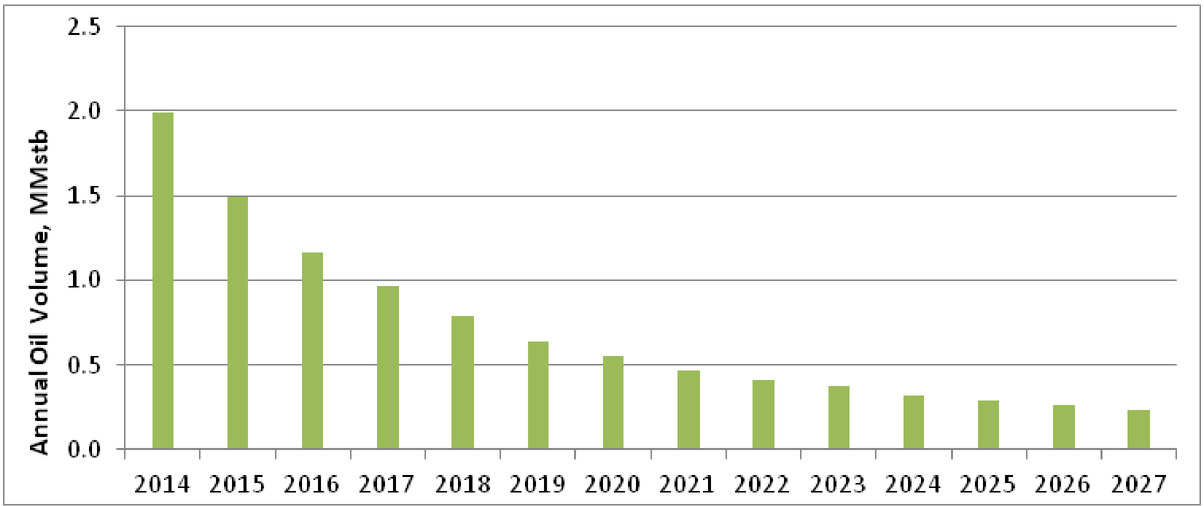


Figure 5-3 Gross 2P Oil Production Forecast - Blane

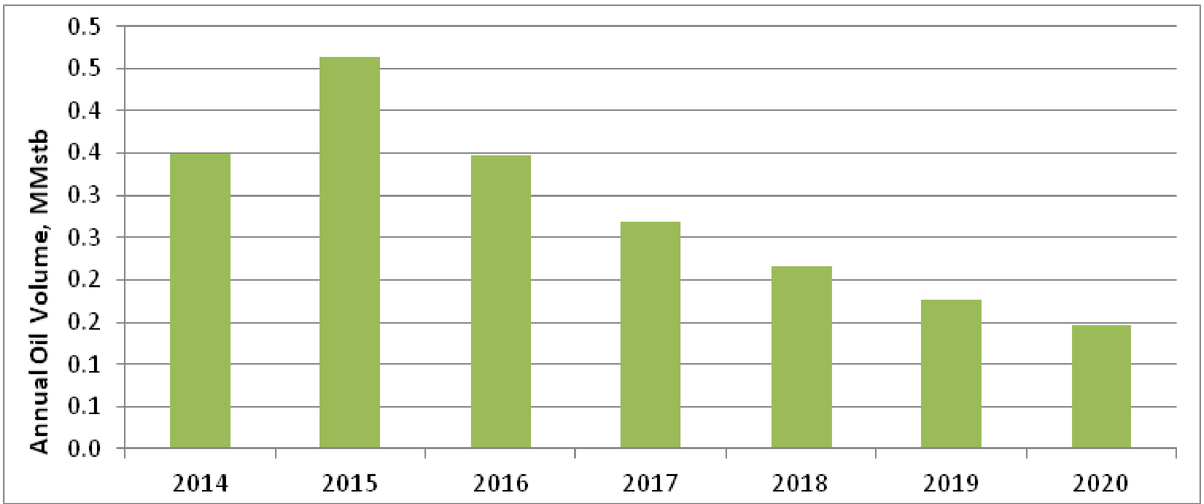


Figure 5-4 Gross 2P Production Forecast - Enoch

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.

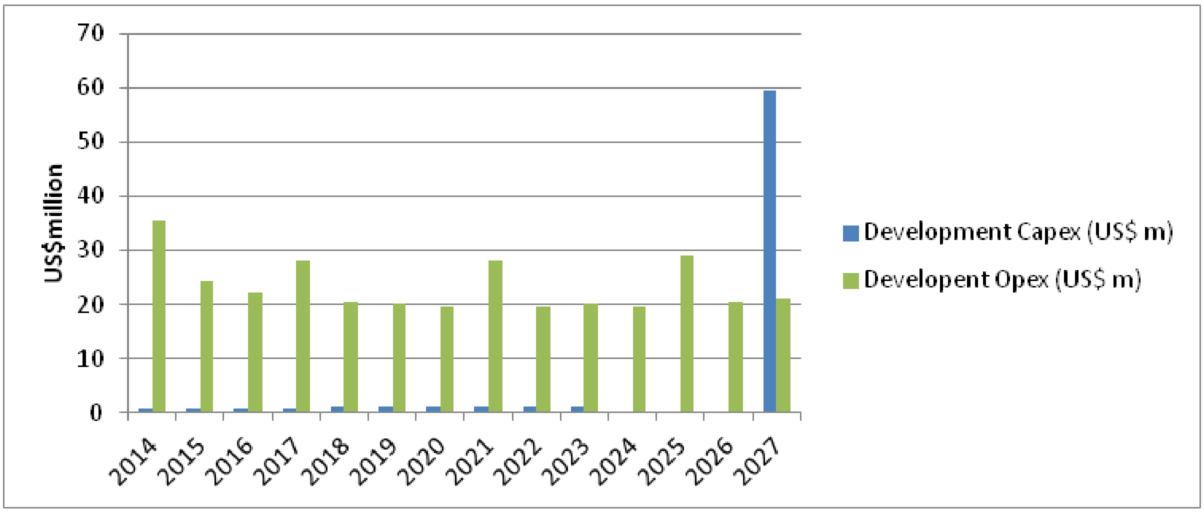


Figure 5-5 Gross Operating Cost Forecast - Blane

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.

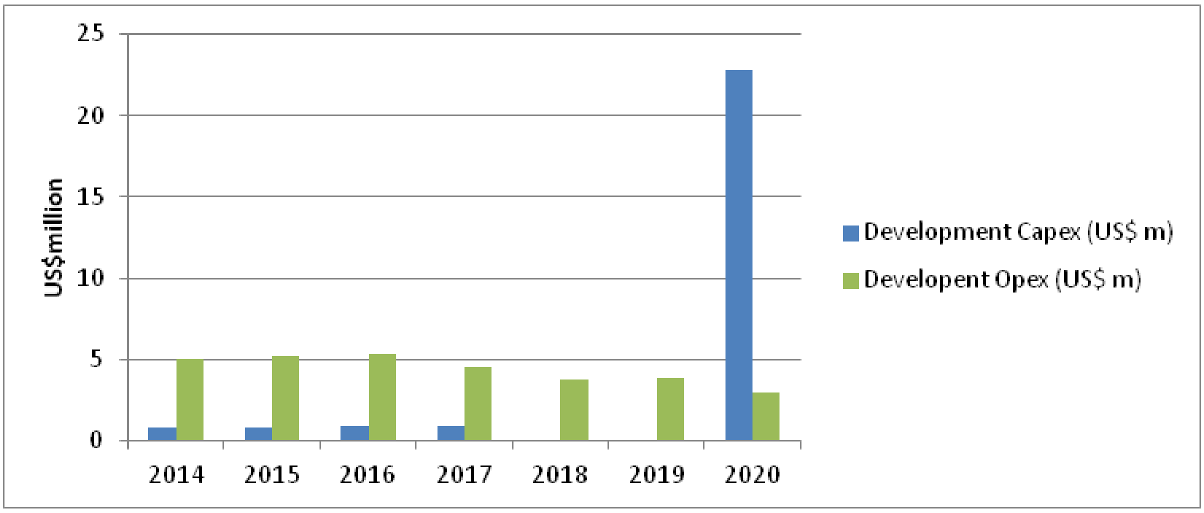


Figure 5-6 Gross Operating Cost Forecast - Enoch

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.

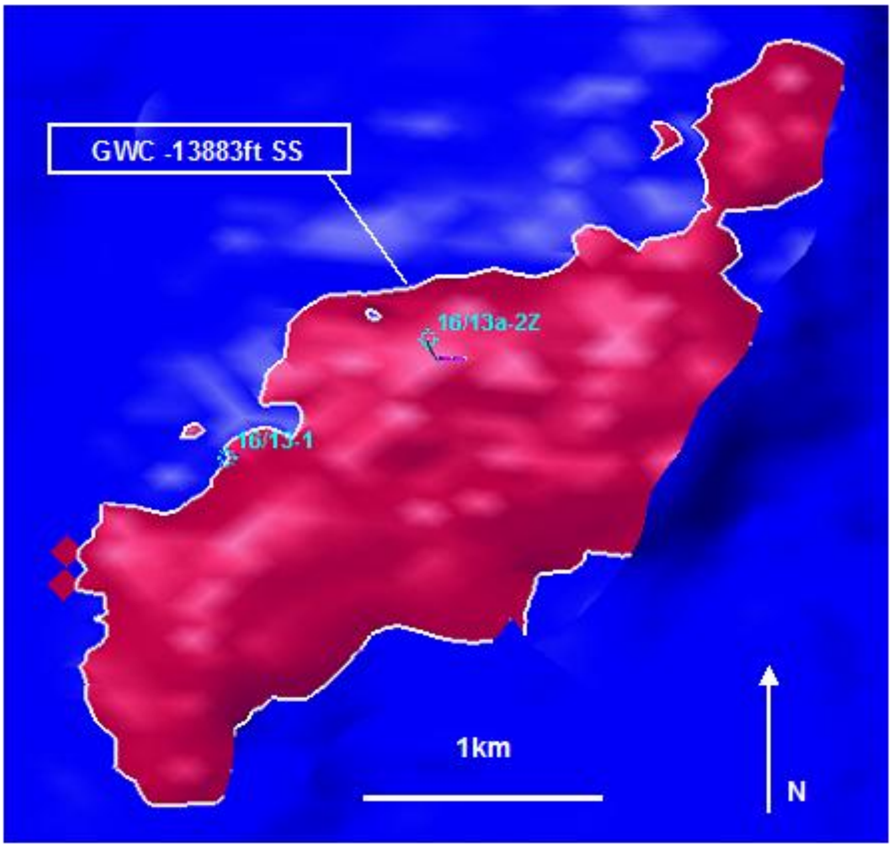


Figure 5-7 Field Outline - J1

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.

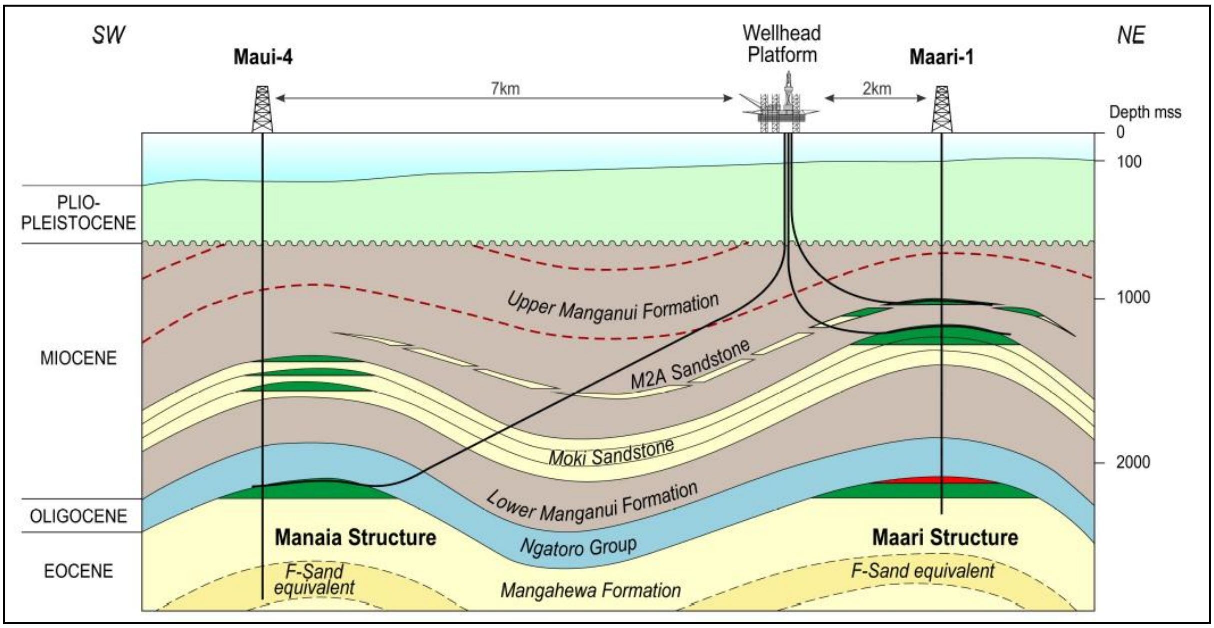


Figure 6-2 Maari Manaia Structural Section (from Horizon)

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.

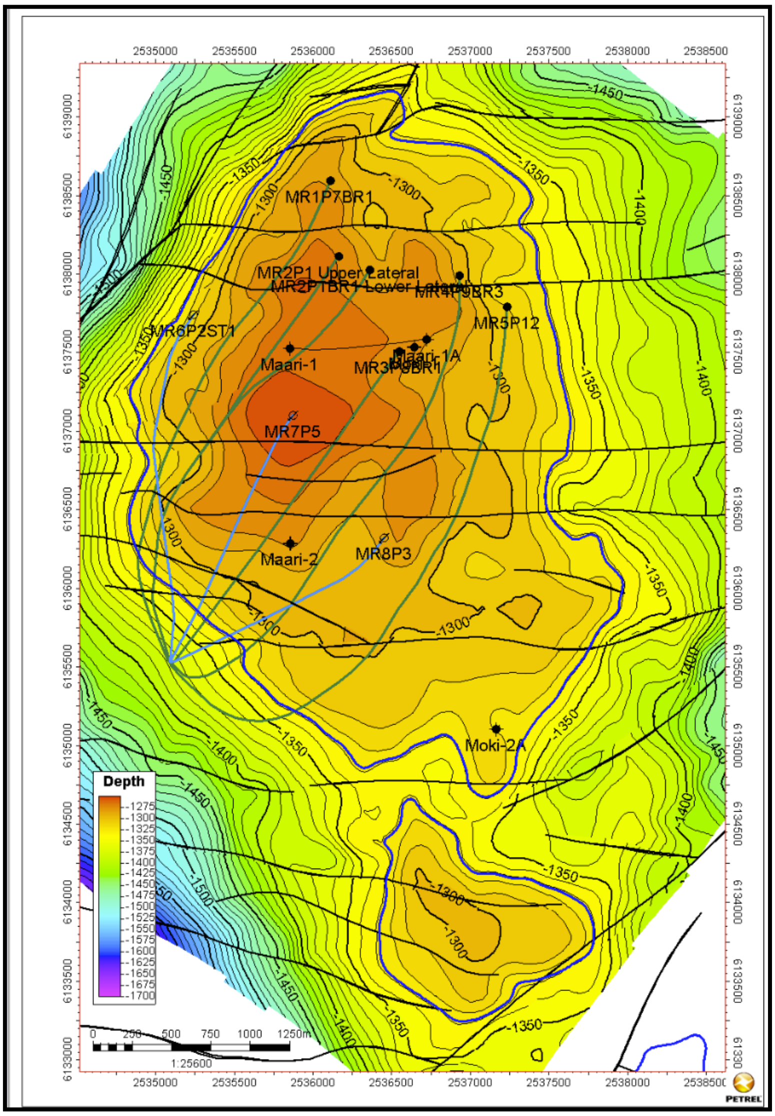


Figure 6-3 Maari Moki Depth Map

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.

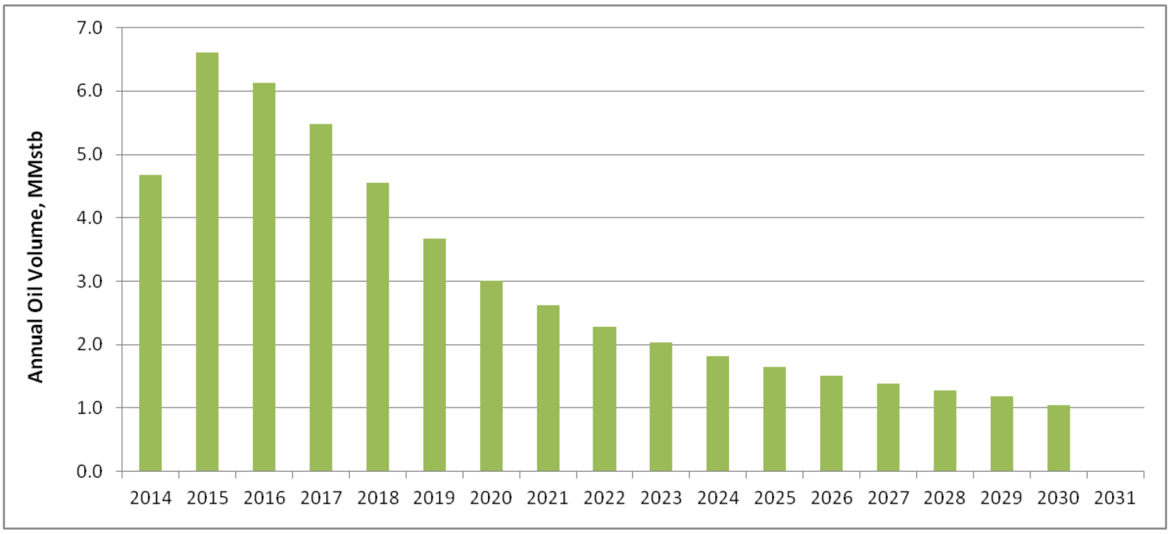


Figure 6-4 Gross 2P Oil Production Forecast - Maari and Manaia

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.

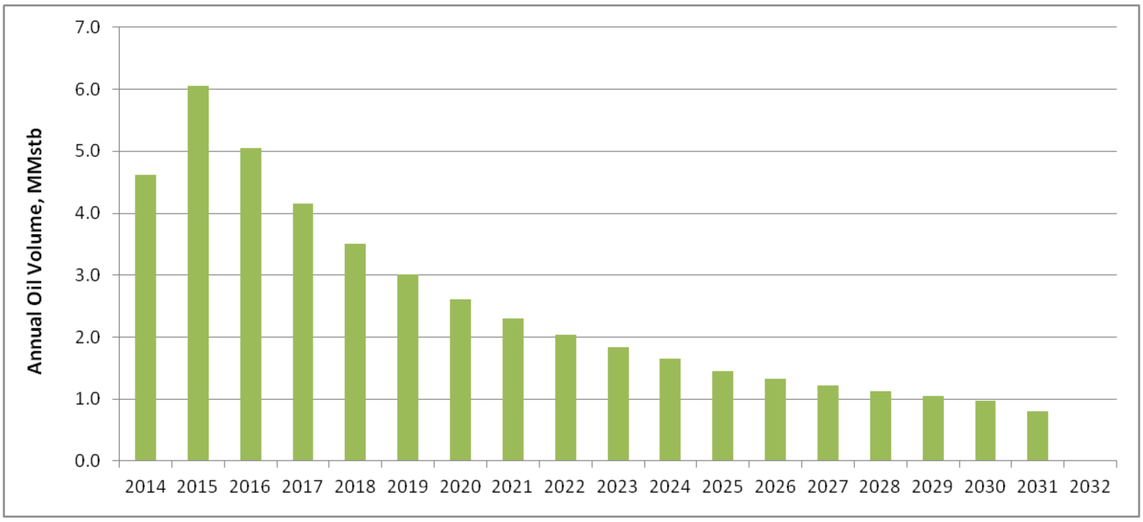


Table 6-4 Gross Oil Production Forecast - No Benefit from Water Injection at Maari Moki Upper

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.

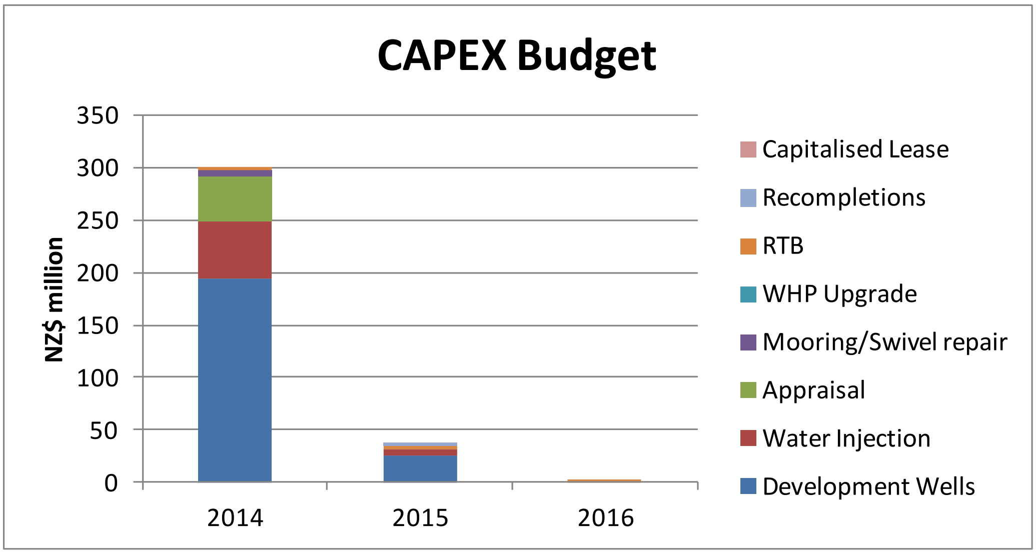


Figure 6-5 Gross Capital Budget - Maari and Manaia Fields

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.

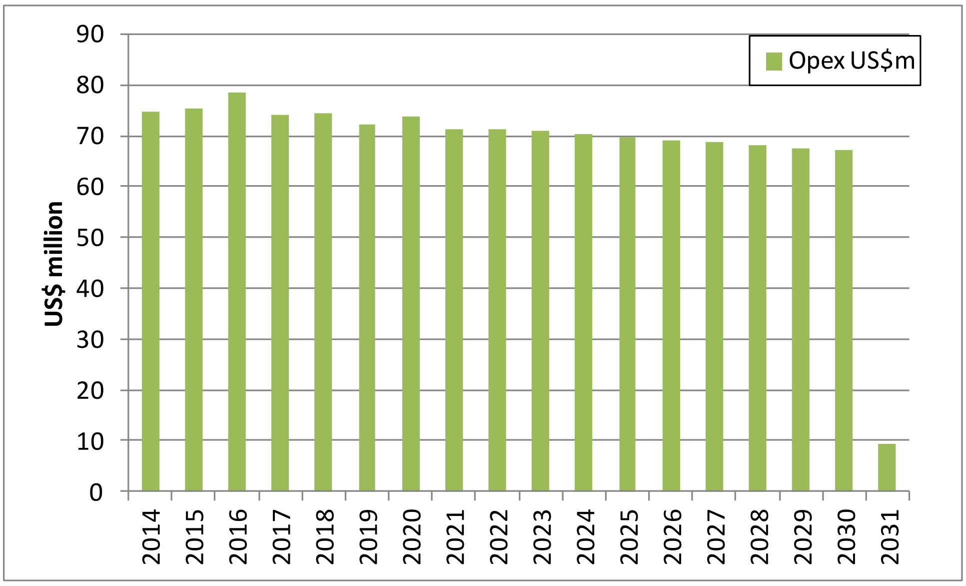


Figure 6-6 Gross Operating Cost Budget - Maari and Manaia Fields

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.

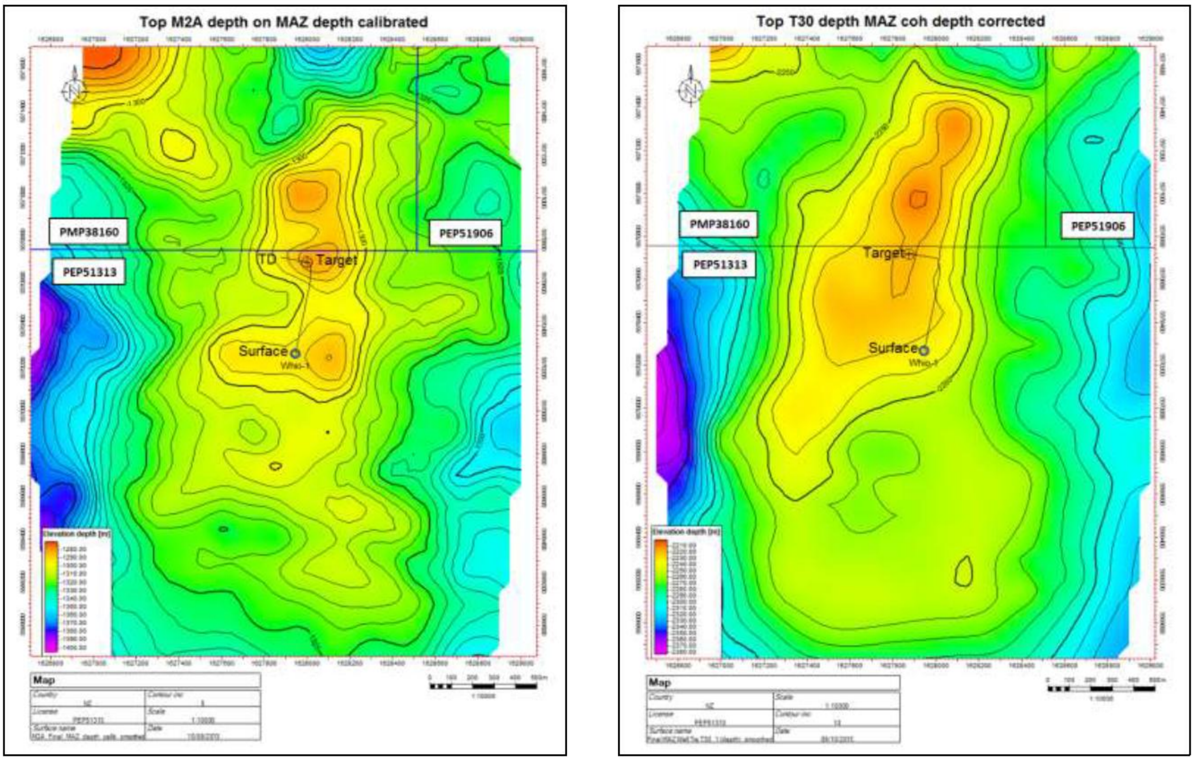


Figure 6-7 Whio Prospect M2A and Moki Depth Maps

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.

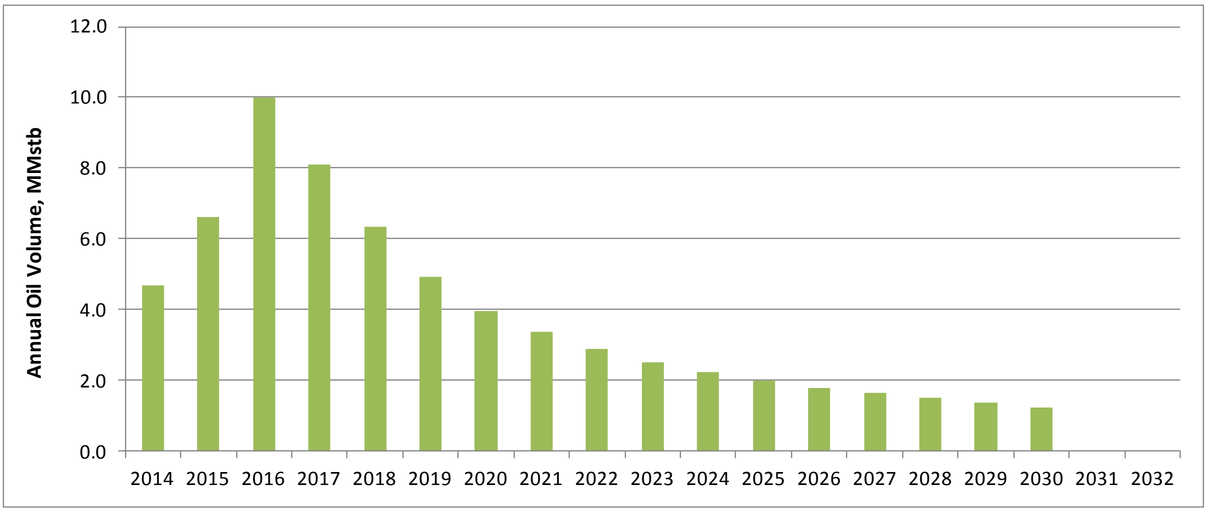


Figure 6-8 Maari 2P + Best Estimate Gross Production Forecast - Whio Prospect

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.

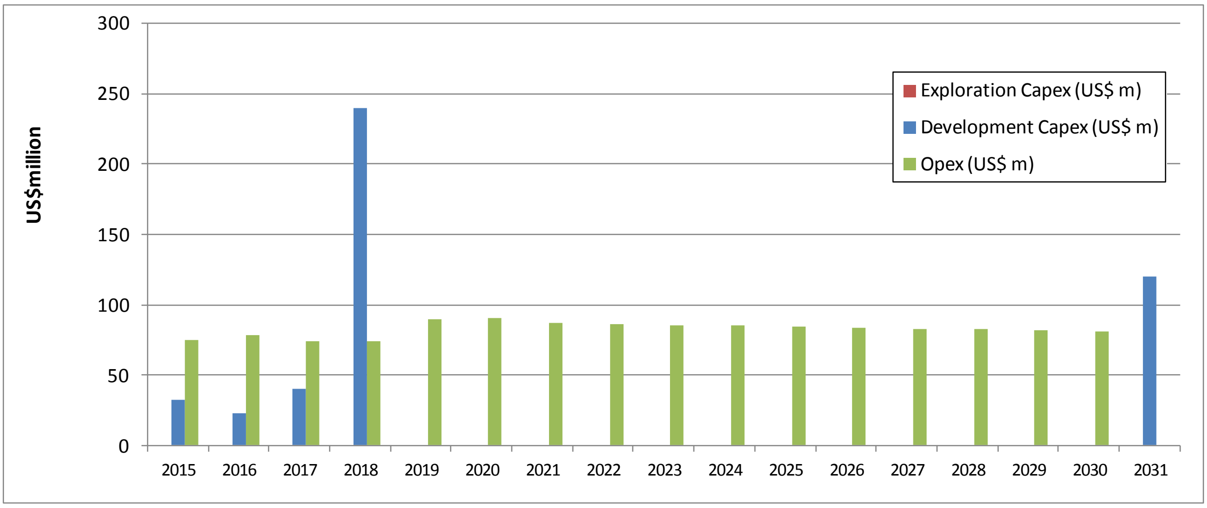


Figure 6-9 Gross Capex and Opex - Whio Prospect

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.

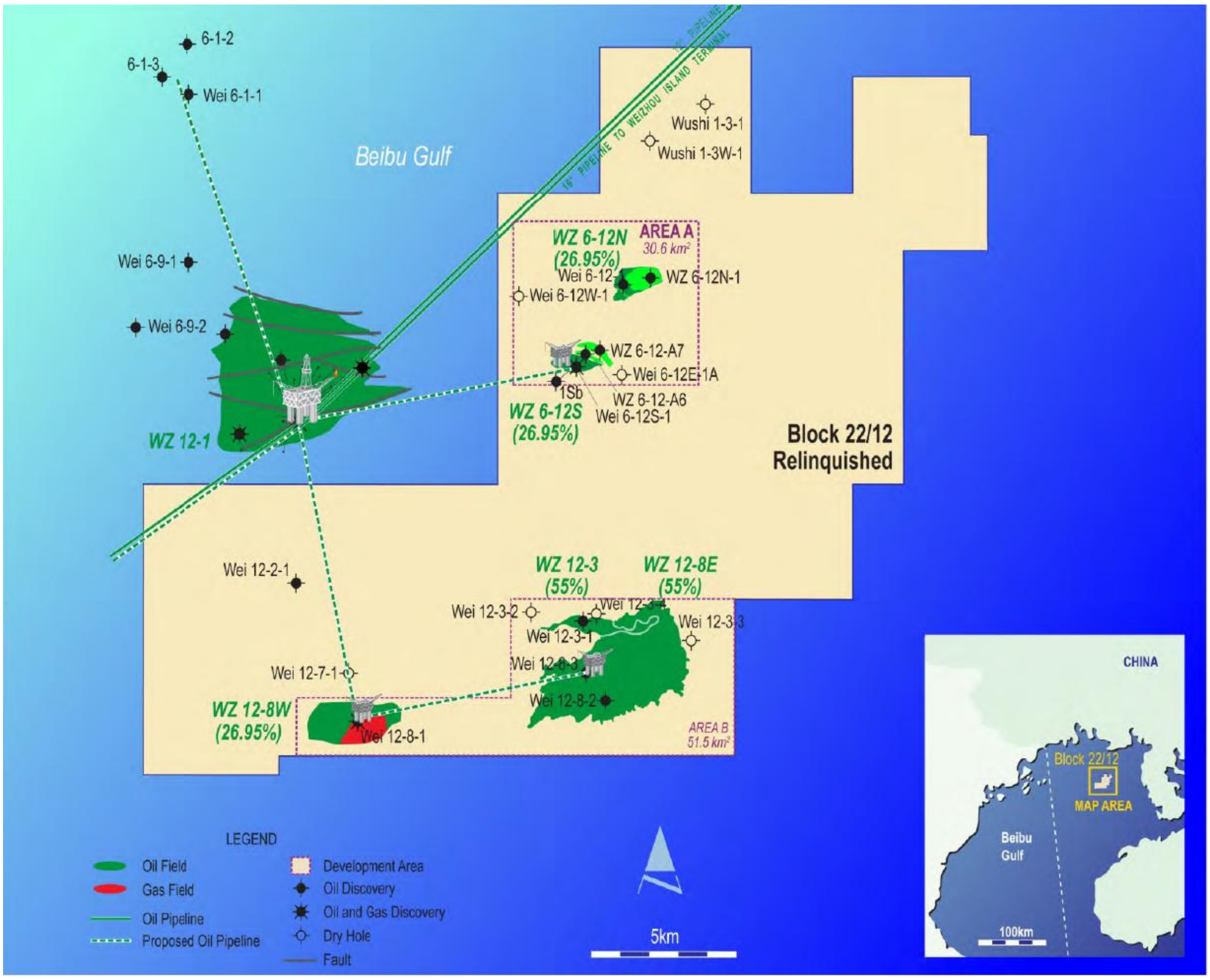


Figure 7-1 Location Map – Beibu Block 22-12

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

Field	Reserves (MMstb)	
	1P	2P
WZ 6-12 South and Sliver Block	7.1	8.9
WZ 6-12 North	8.7	10.1
WZ 12-8 West	4.1	5.4
Total	19.9	24.4

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.

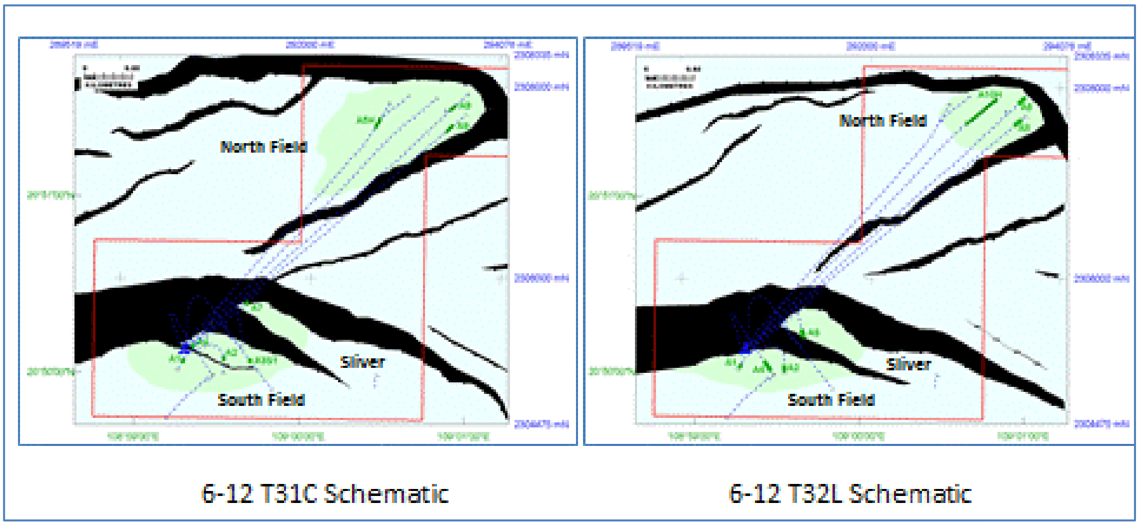


Figure 7-2 Well locations and schematic North, South and "Sliver" Block Field Areas

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.

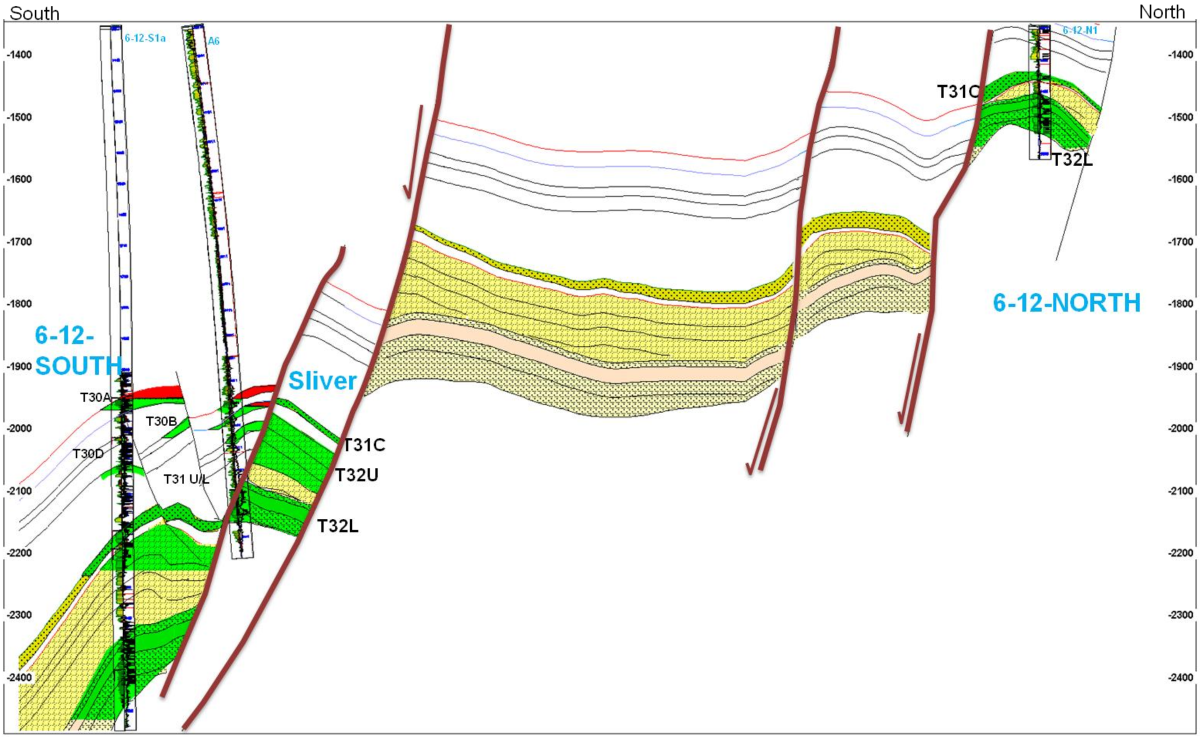


Figure 7-3 Structural relationship of WZ 6-12 South, "Sliver" and North Fields

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.

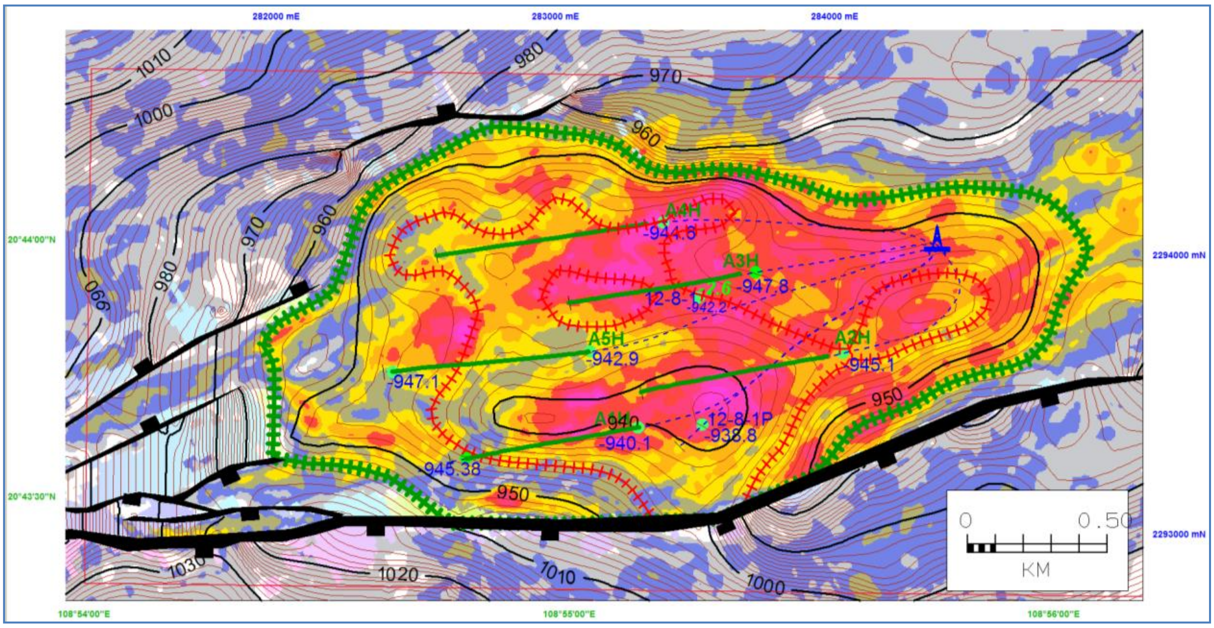


Figure 7-4 Final well tied top J2 reservoir depth structure map (post development drilling)

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.

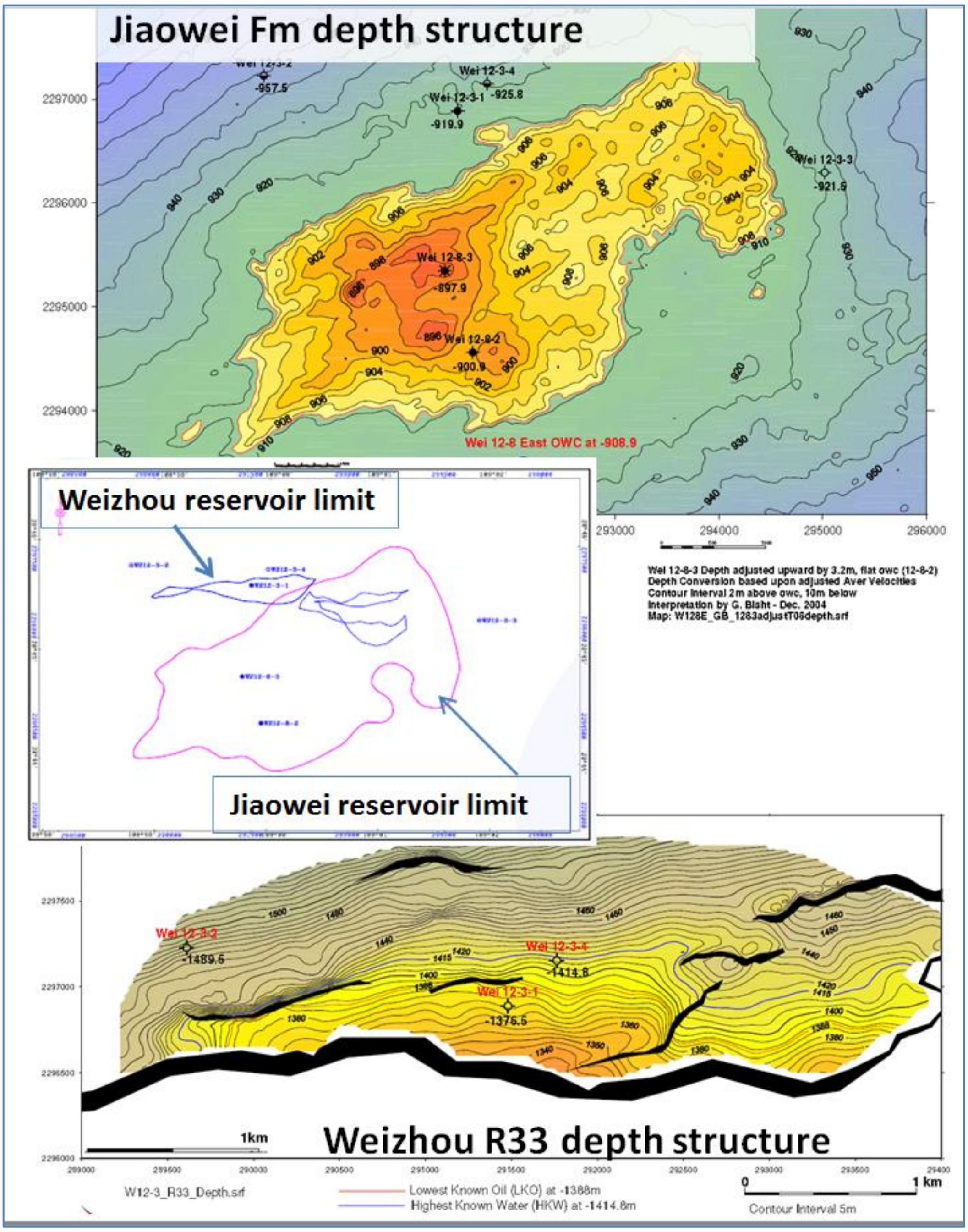


Figure 7-5 WZ12-8 East reservoir depth structure maps and field limits

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.

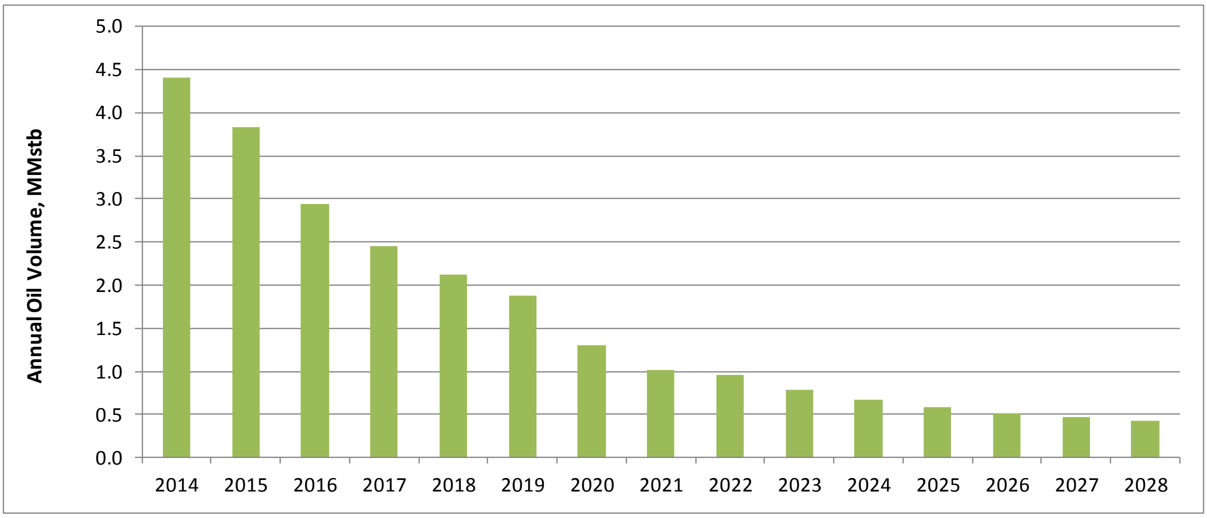


Figure 7-6 Gross 2P Oil Production Forecast - Beibu WZ6-12 N, 6-12 S and 12-8 W

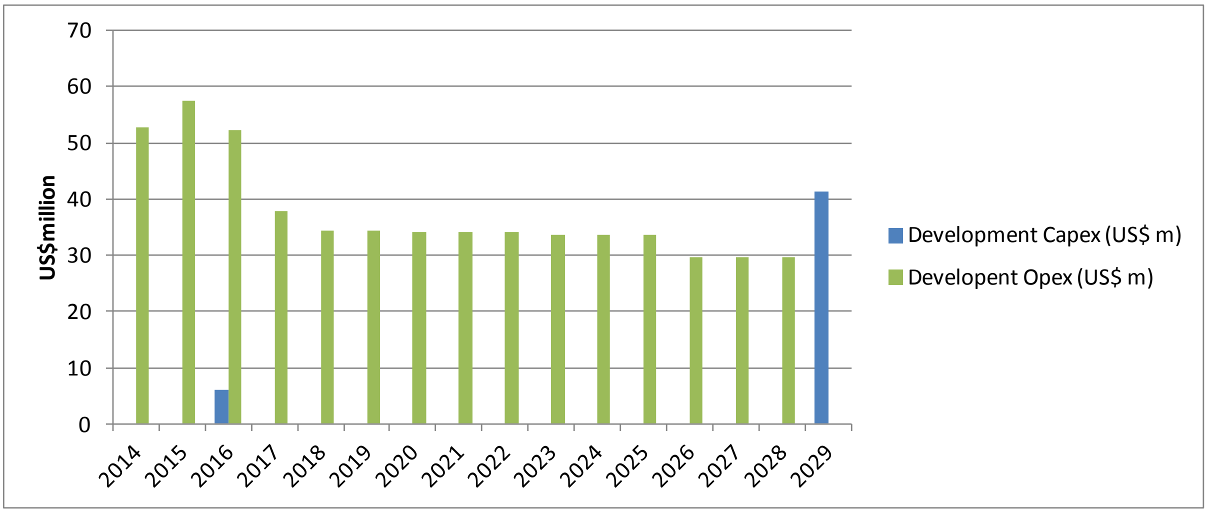


Table 7-4 Gross 2P Cost Forecast - Beibu WZ6-12, 6-12 S and 12-8 W

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.

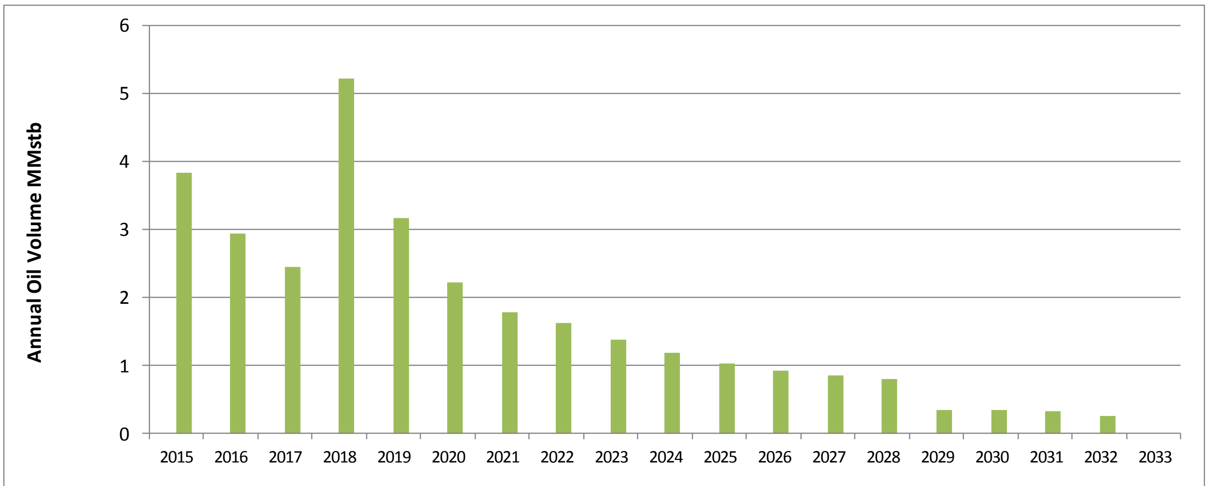


Figure 7-7 Gross 2P+2C Gross Production Forecast – 2P Plus WZ12-8E

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.

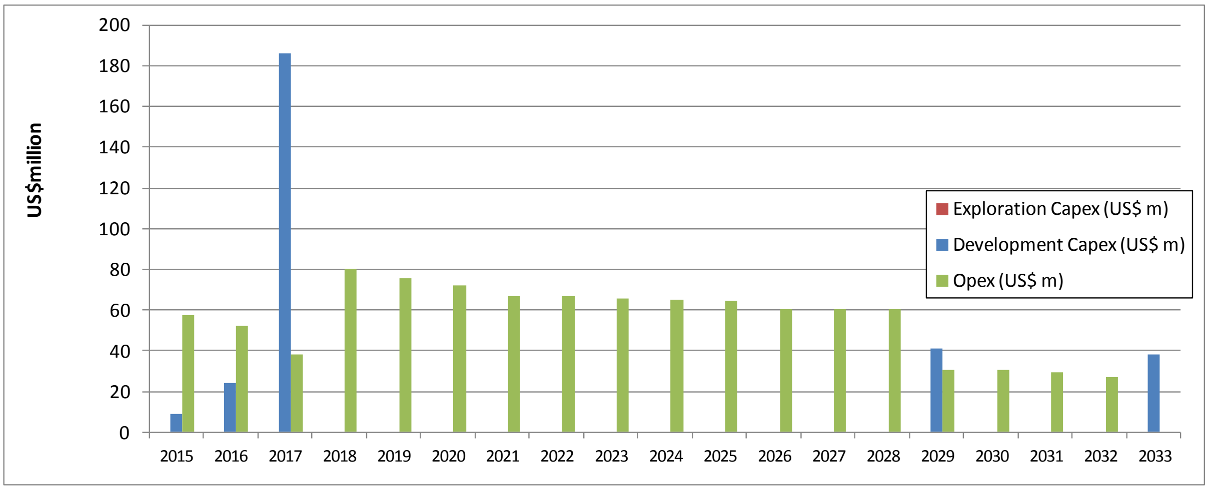


Figure 7-8 2P+2C Cost Forecast – 2P Plus WZ12-8E

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.

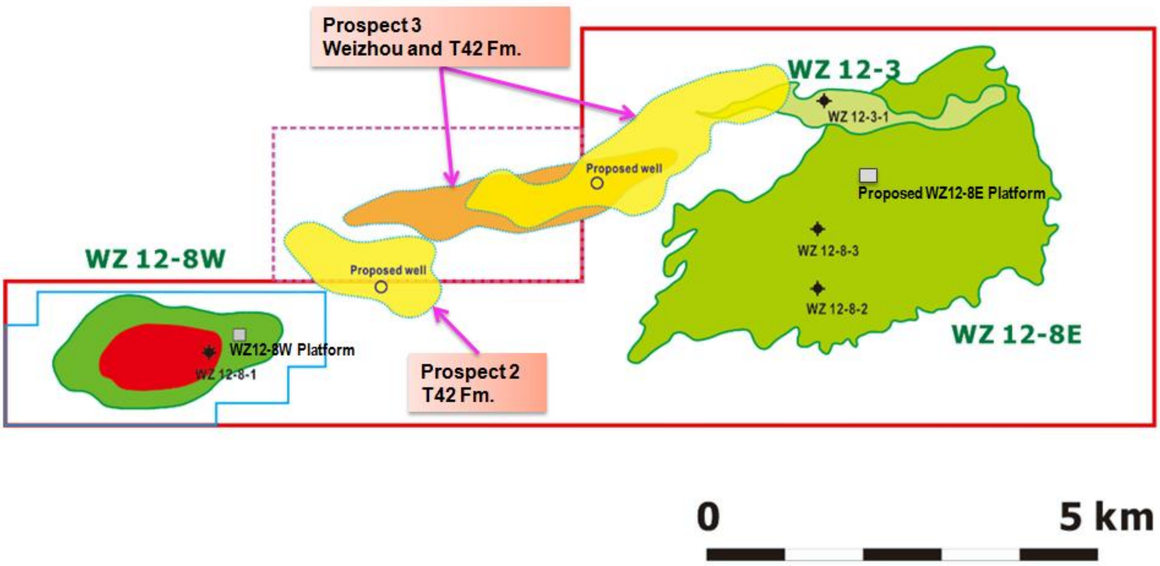


Figure 7-9 Beibu Gulf Exploration Prospects (subject to approval of license boundary extension shown in dotted red line)

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.

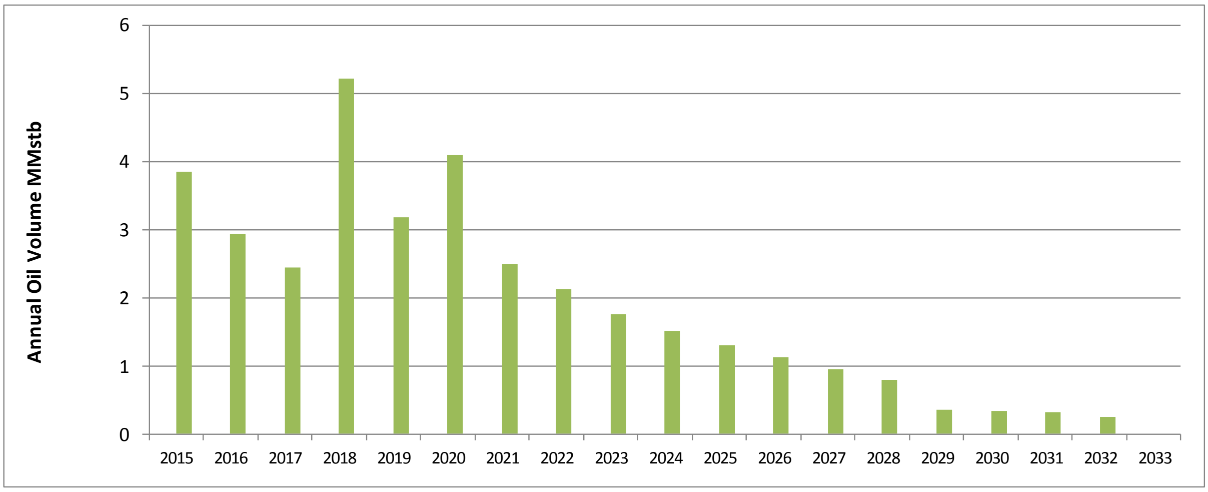


Figure 7-10 Gross Production Forecast: 2P Plus 2C Plus Prospect-3

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.

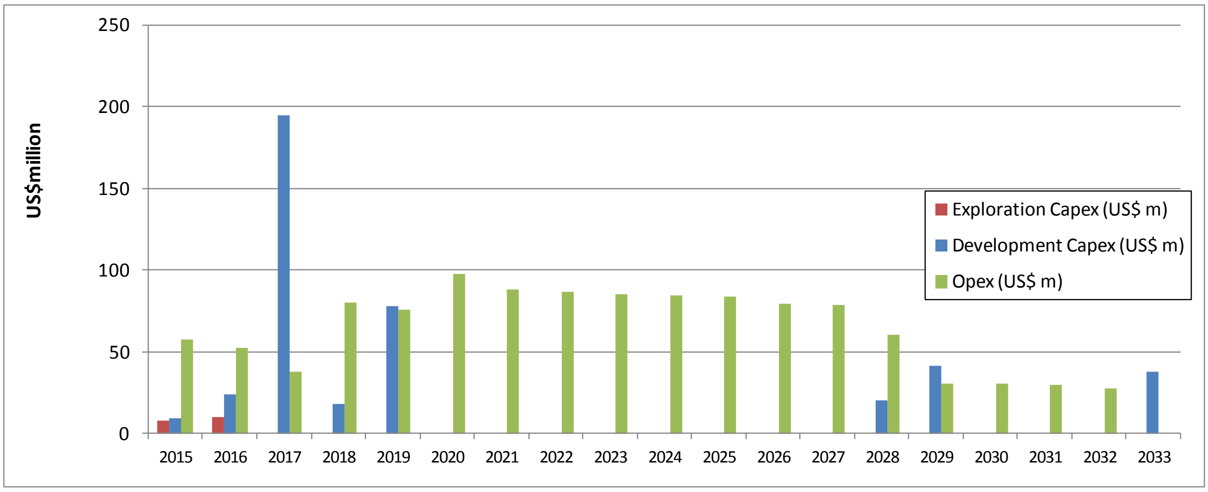


Figure 7-11 Cost Forecast 2P + 2C + Prospect-3

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

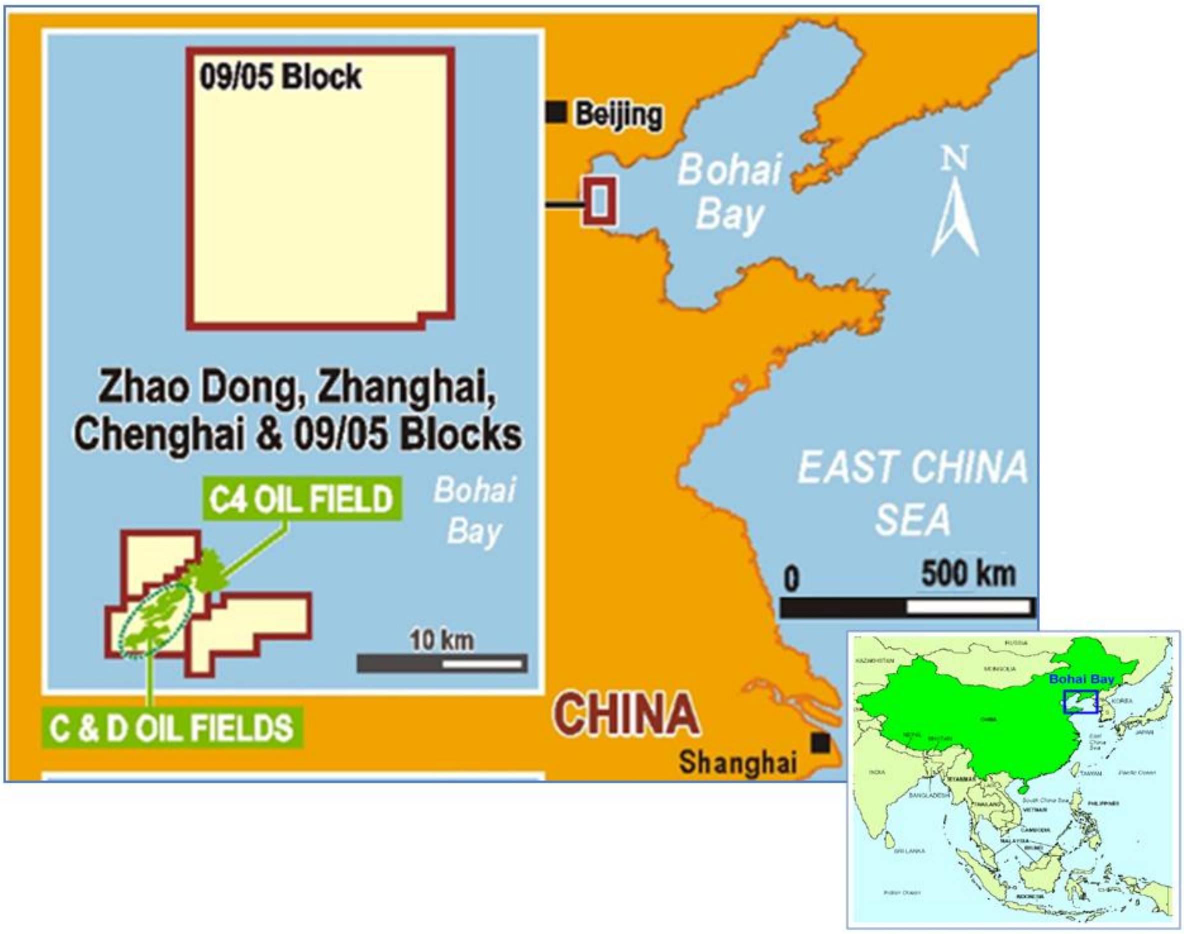


Figure 7-12 Location Map – Bohai Bay

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.

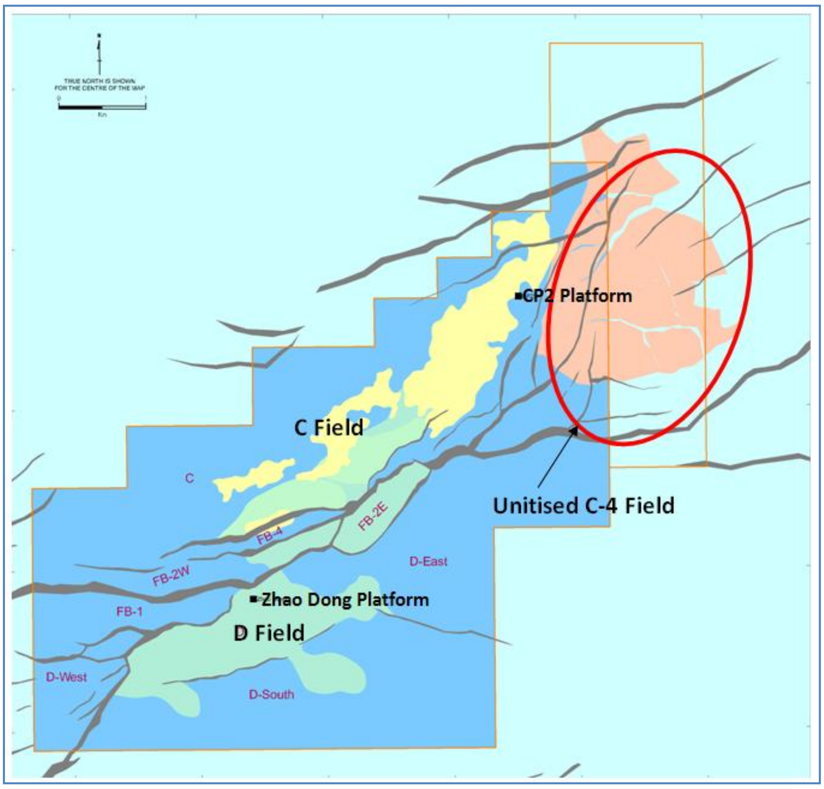


Figure 7-13 Zhao Dong and C4 oil accumulation map

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.

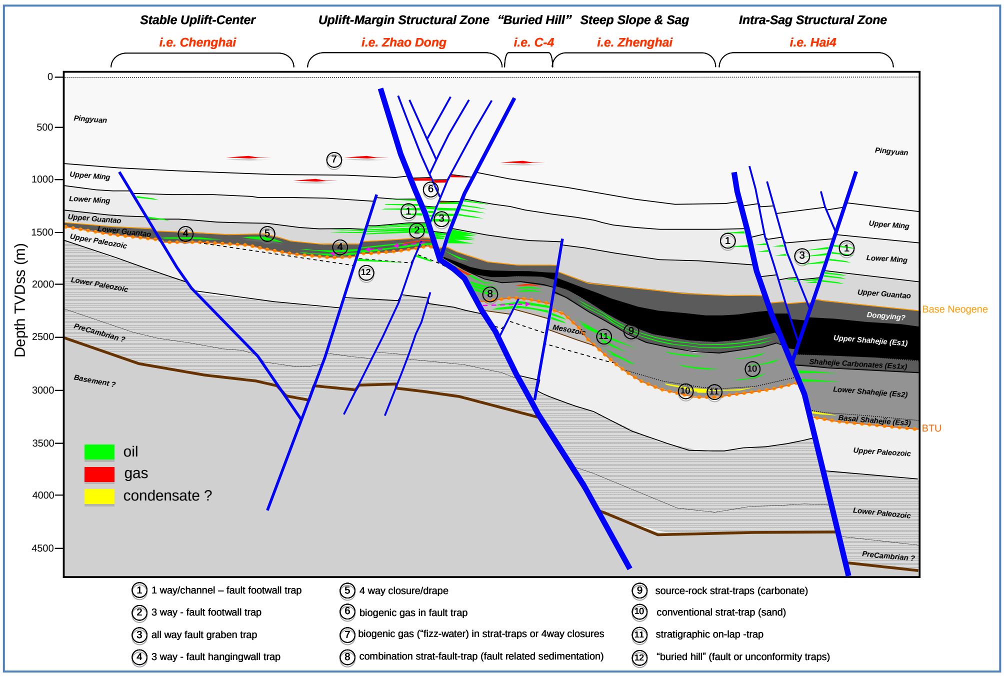


Figure 7-14 Schematic cross-section showing typical plays

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.

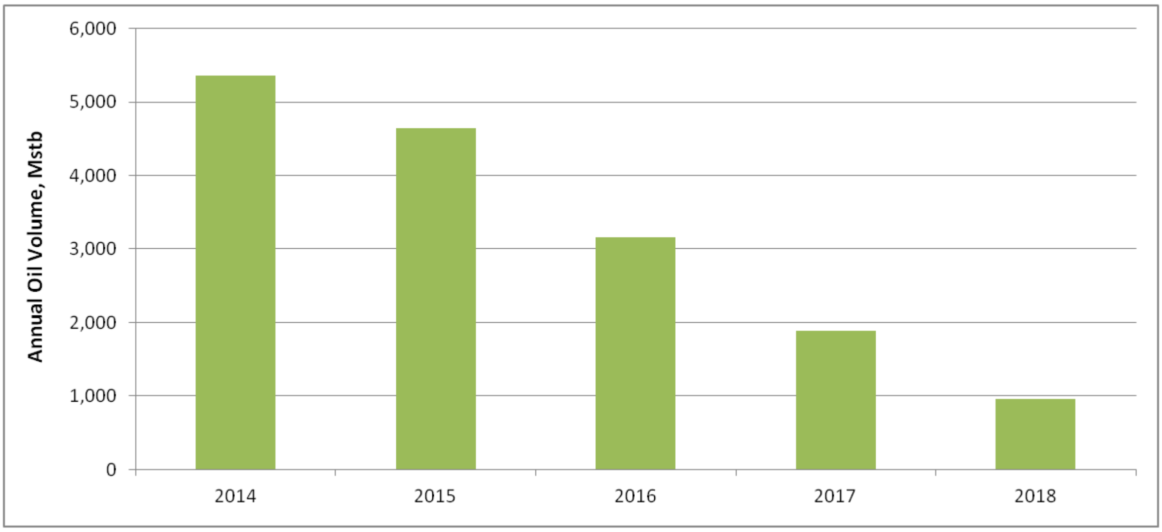


Figure 7-15 2P Gross Oil Production Forecast - C&D Fields

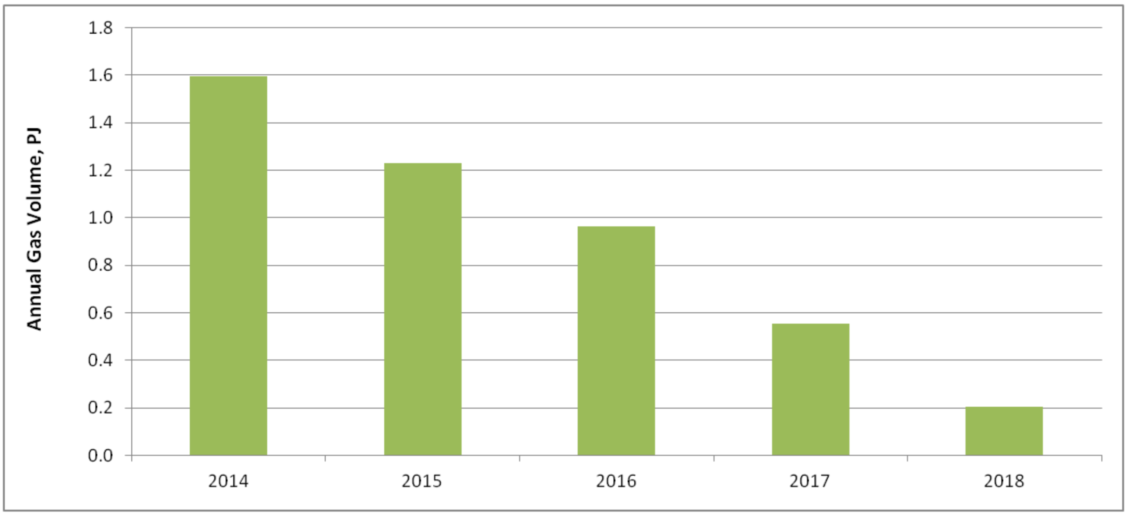


Table 7-9 2P Gross Sales Gas Production Forecast - C&D Fields

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.

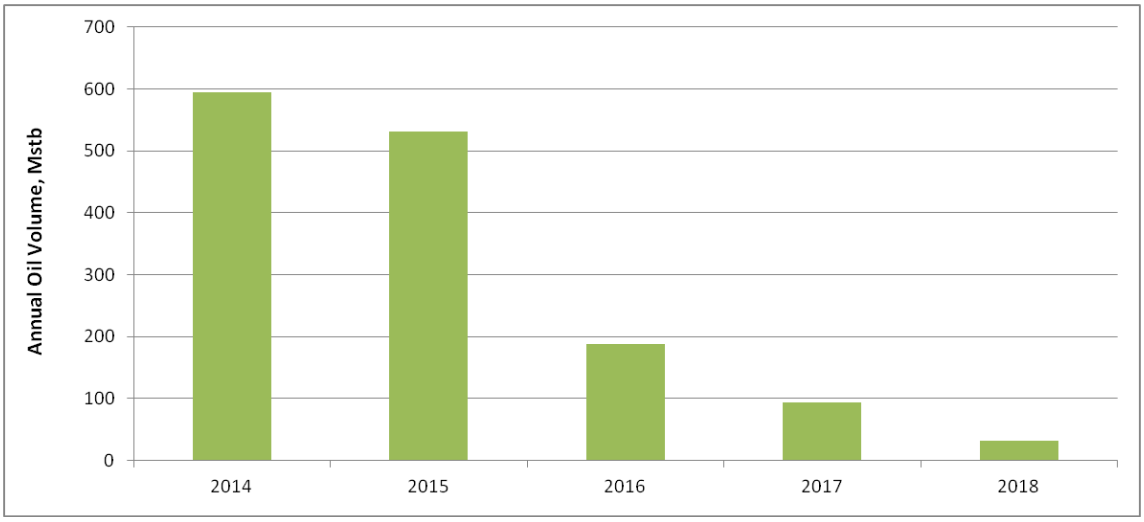


Figure 7-16 2P Gross Oil Production Forecast - C-4 Field

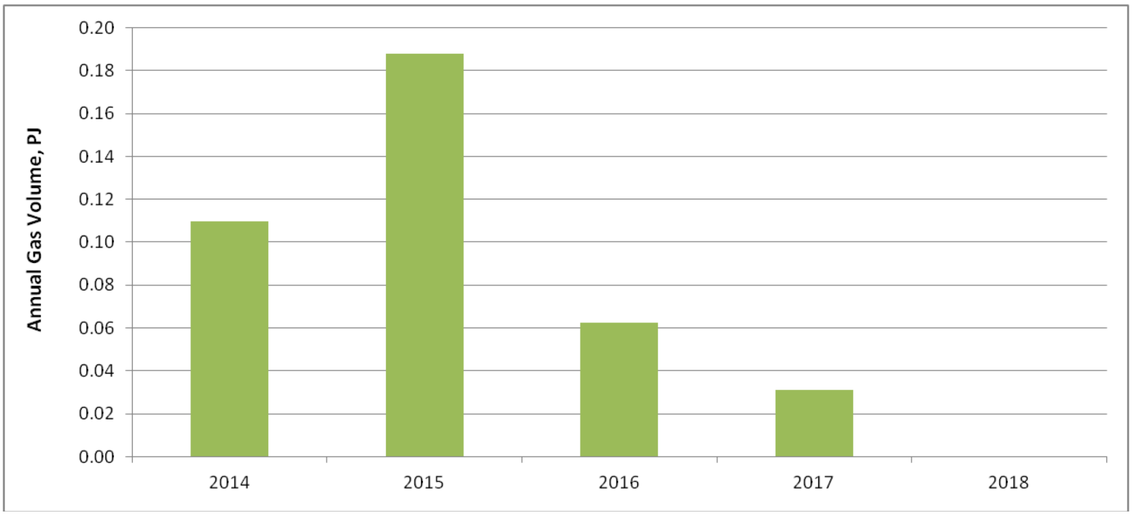


Table 7-10 2P Gross Gas Production Forecast - C-4 Field

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.

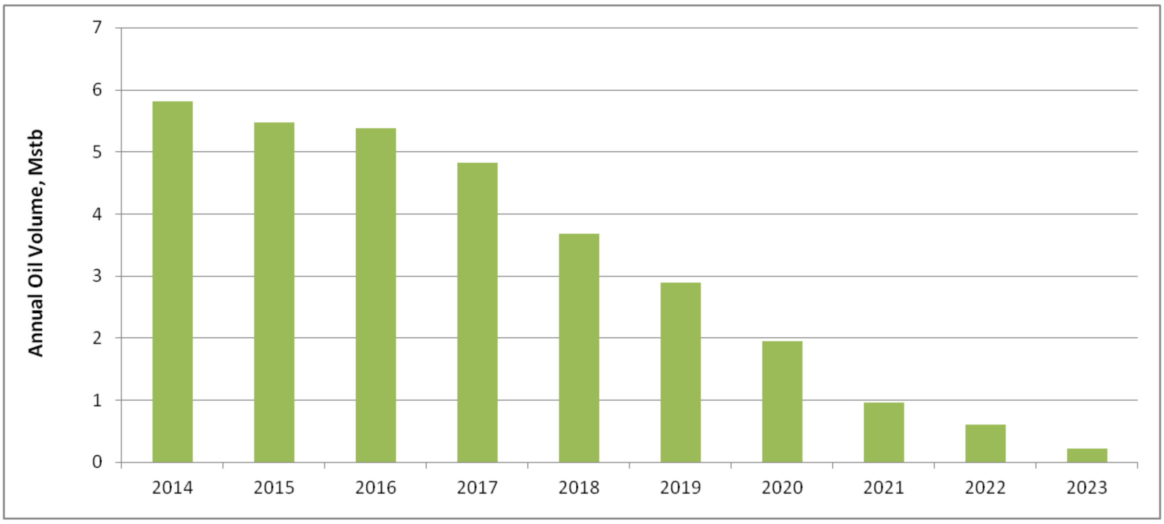


Figure 7-17 2P+2C Gross Oil Production Forecast - All Fields

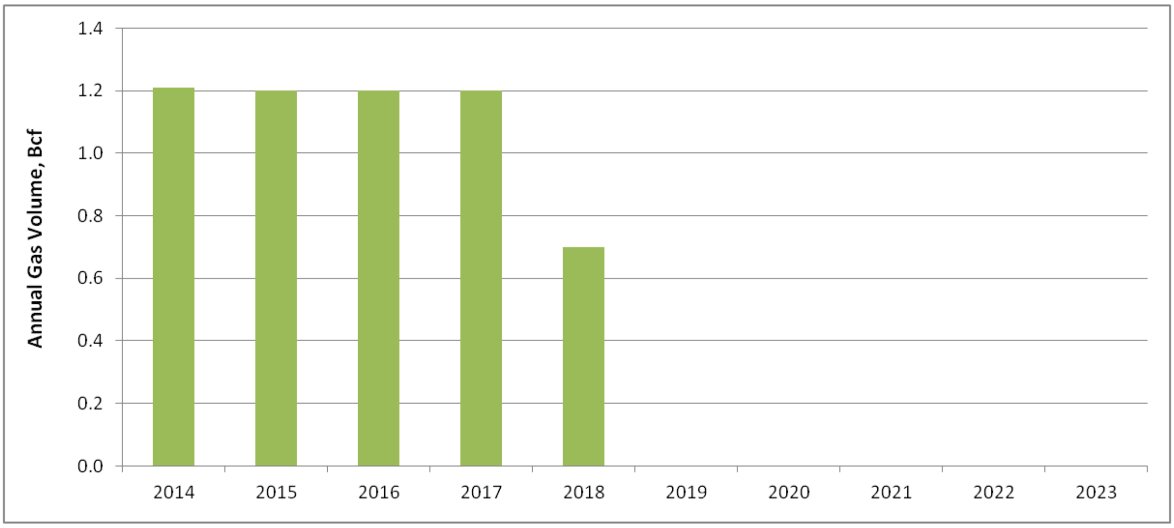


Figure 7-18 2P+2C Gross Gas Sales Forecast - All Fields

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.

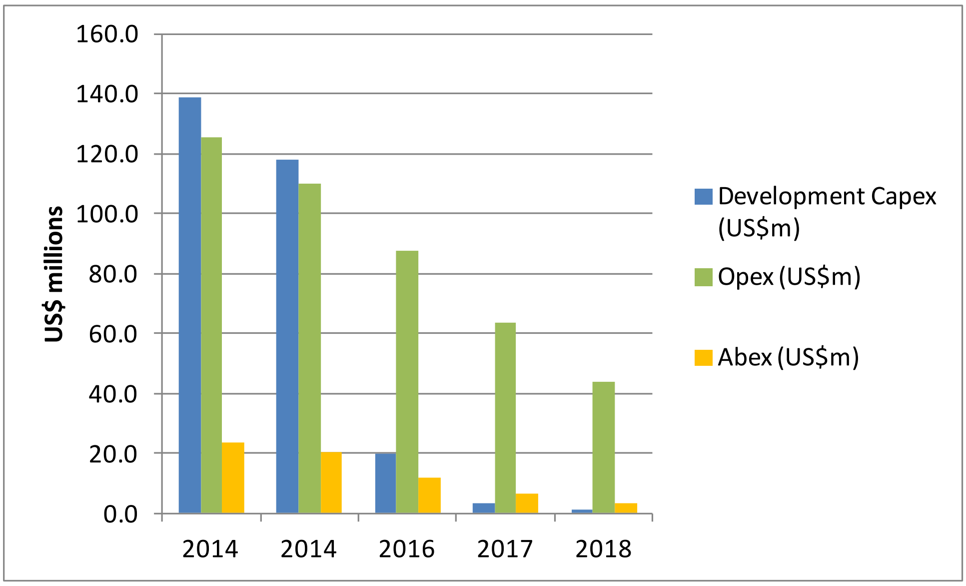


Figure 7-19 Gross 2P Costs - Bohai Bay

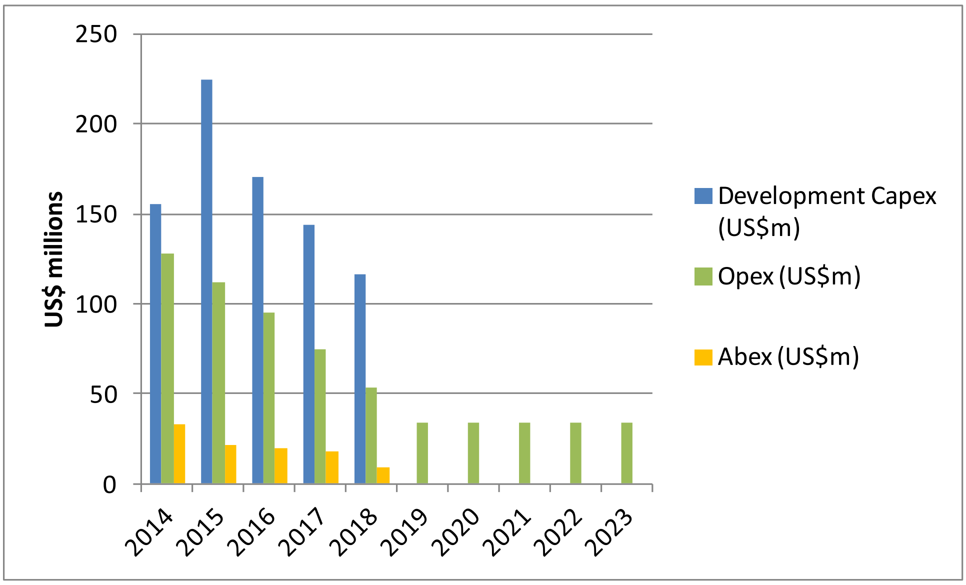


Figure 7-20 Gross 2P+2C Costs - Bohai Bay

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.

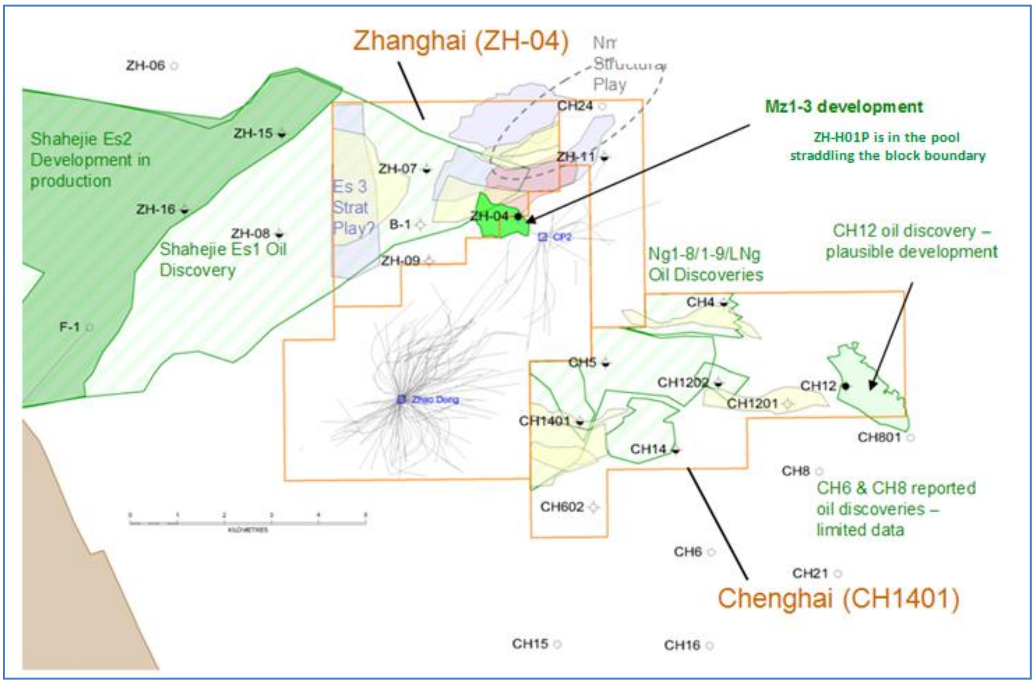


Figure 7-21 Map showing Zhaghai and Chenghai Blocks, Zhao Dong wells and Discoveries

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.

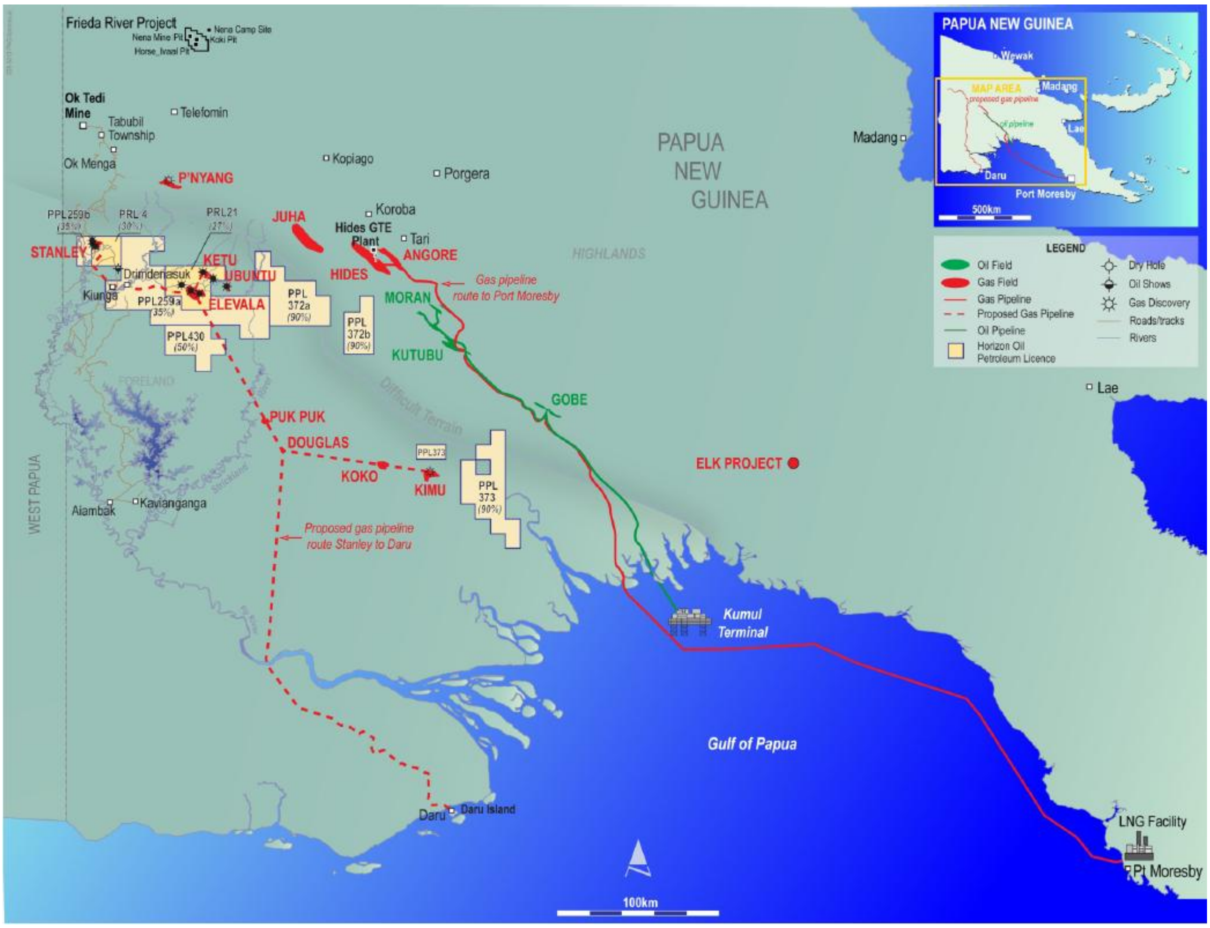


Figure 8-1 Horizon PNG Interest Location Map

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.

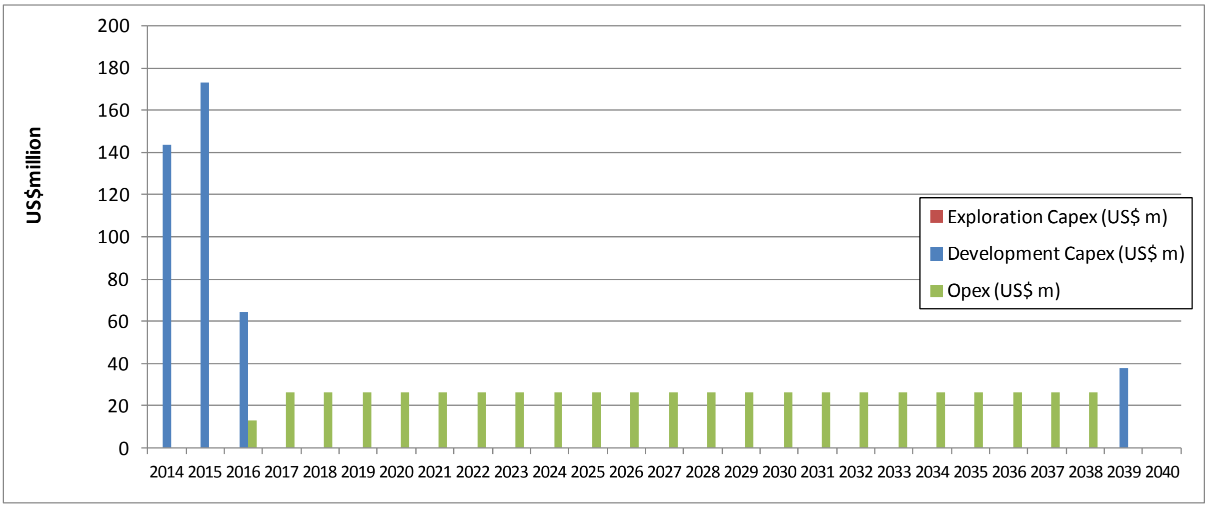


Figure 8-2 Stanley 2P Liquids Stripping Gross Cost Forecast - RISC Estimate

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.

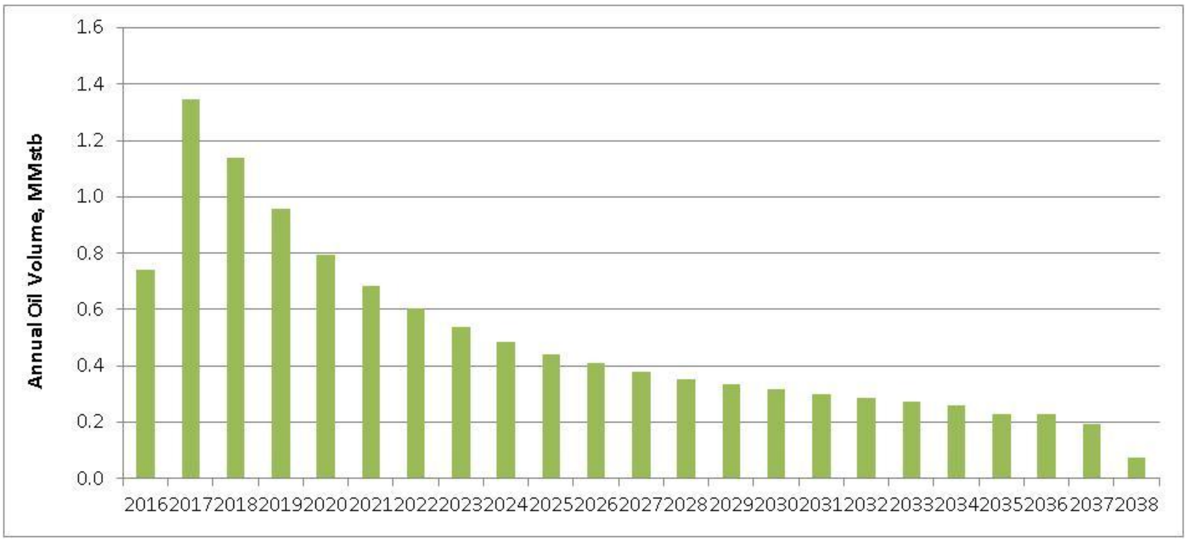


Figure 8-3 Stanley 2P Gross Production Forecast – Condensate stripping only

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.

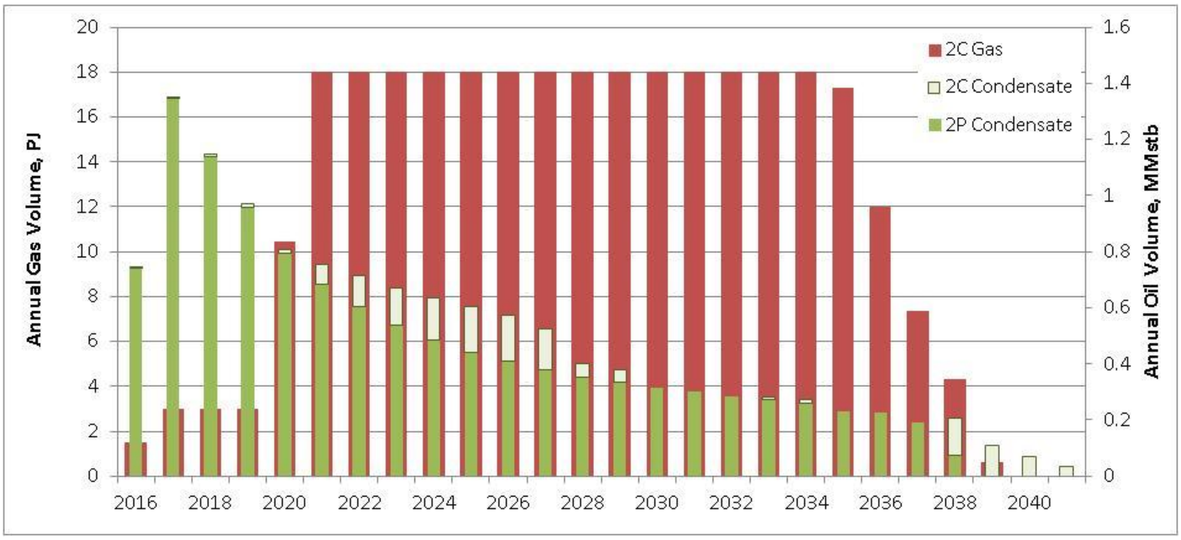


Figure 8-4 2P+2C Gross Production Forecast – Condensate stripping and gas export

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).

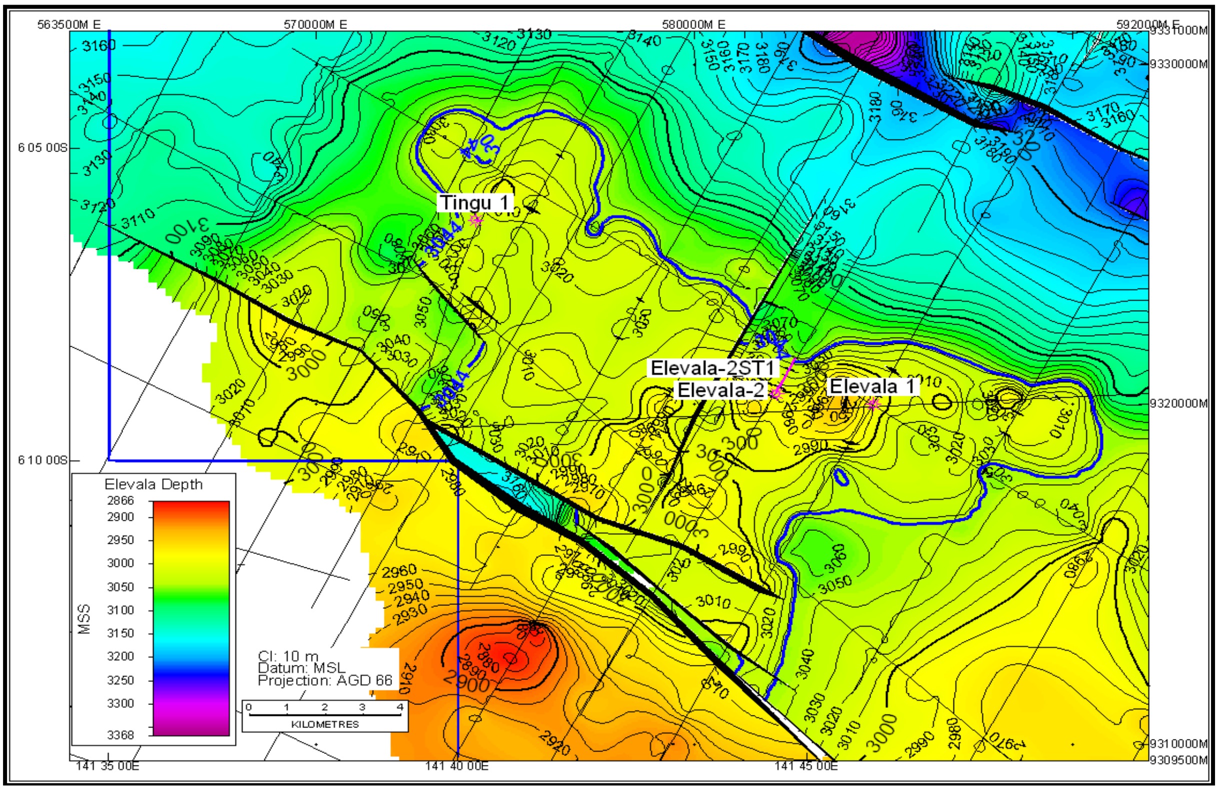


Figure 8-5 Elevala Field Elevala Reservoir Depth Structure Map

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.

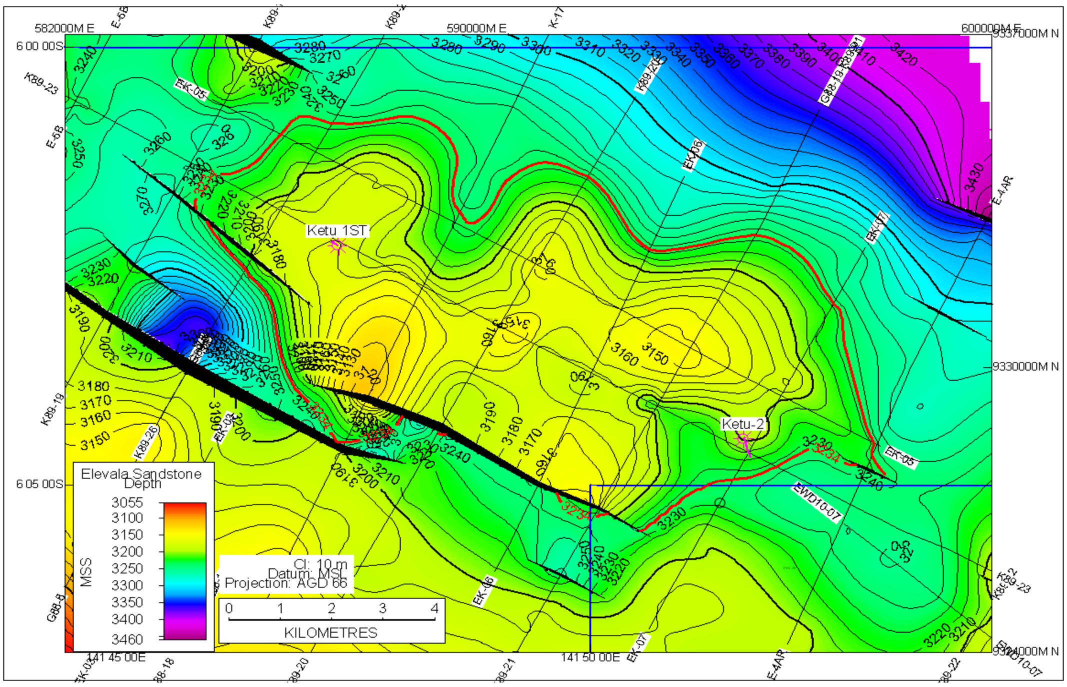


Figure 8-6 Ketu Field Elevala Reservoir Depth Structure Map

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.

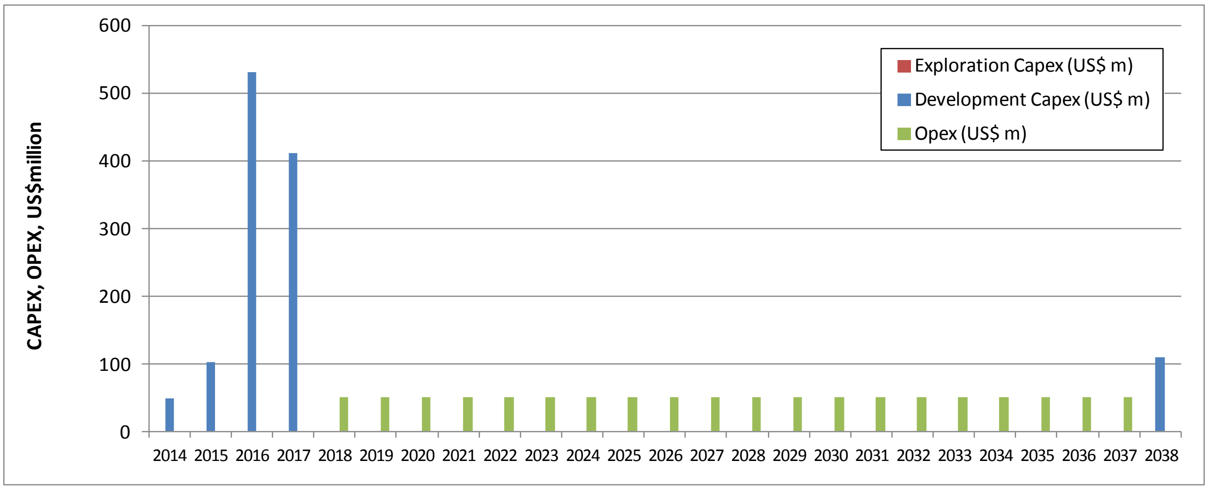


Figure 8-7 Elevela-Ketu Gross Cost Forecast - Liquids Stripping Only 1/1/2018 Start Up

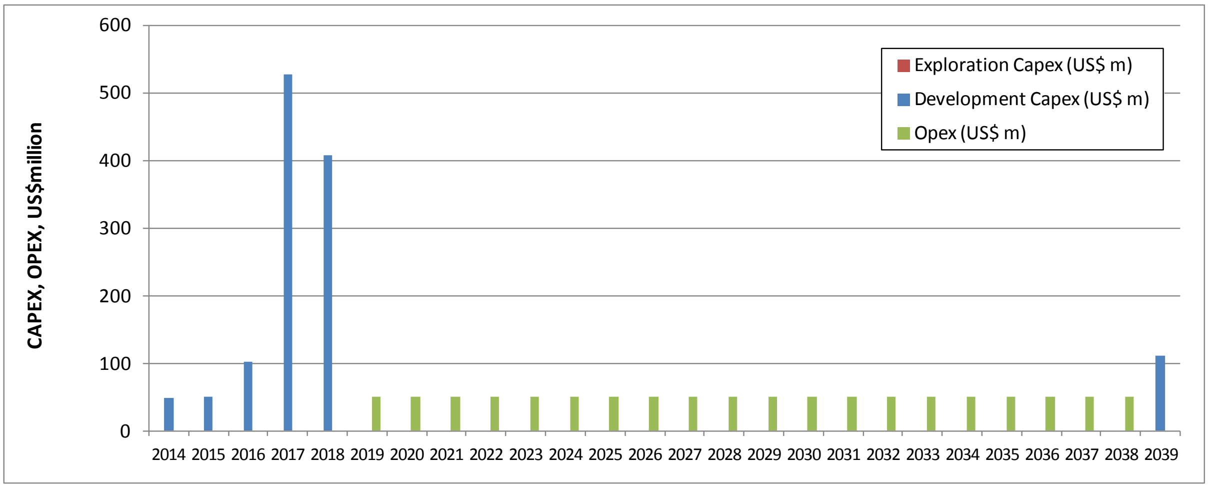


Figure 8-8 Elevela-Ketu Gross Cost Forecast - Liquids Stripping Only 1/1/2019 Start Up

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.

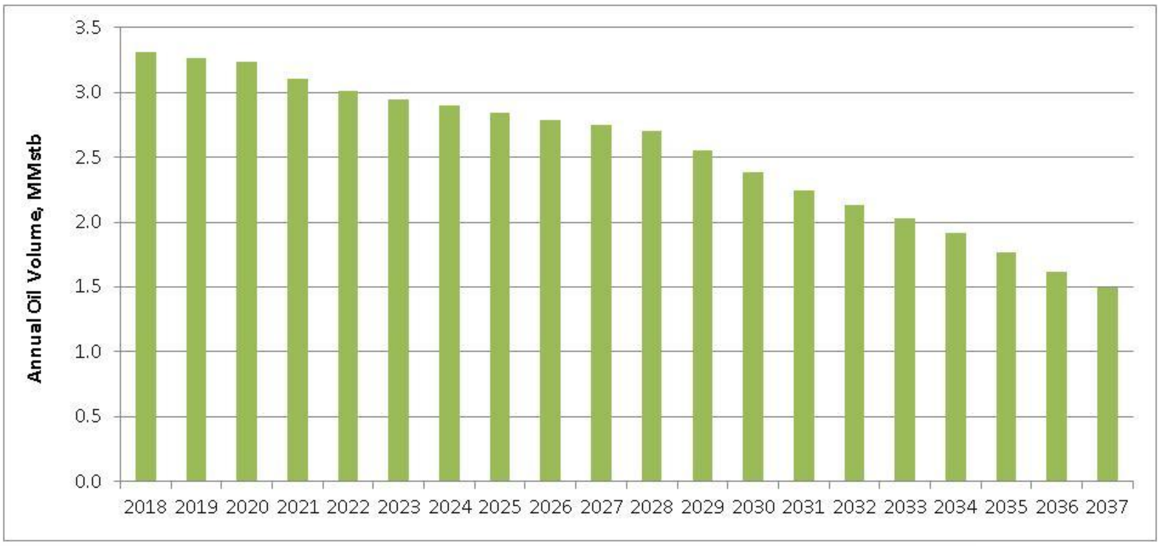


Figure 8-9 Elevala-Ketu 2C Gross Production Forecast – Condensate stripping only

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.

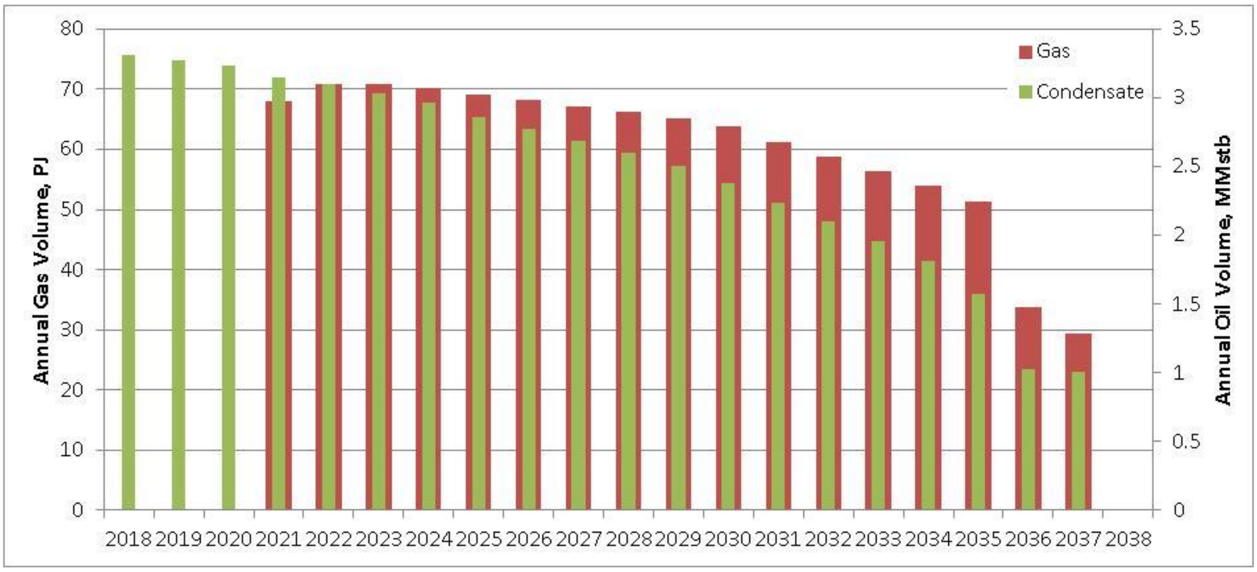


Figure 8-10 Elevala-Ketu 2C Gross Production Forecast – Condensate stripping and gas export

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).

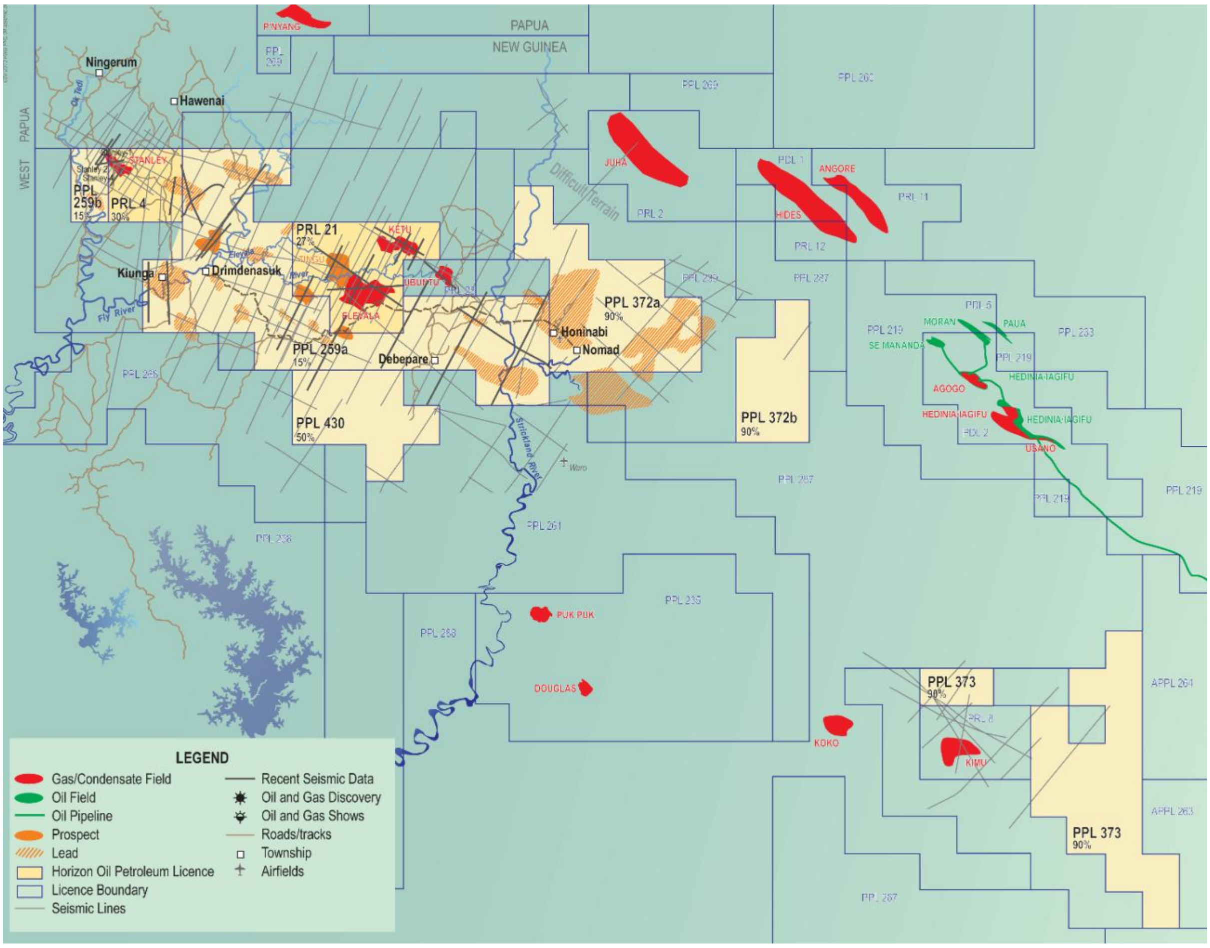


Figure 8-11 Horizon PNG Exploration Acreage

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.

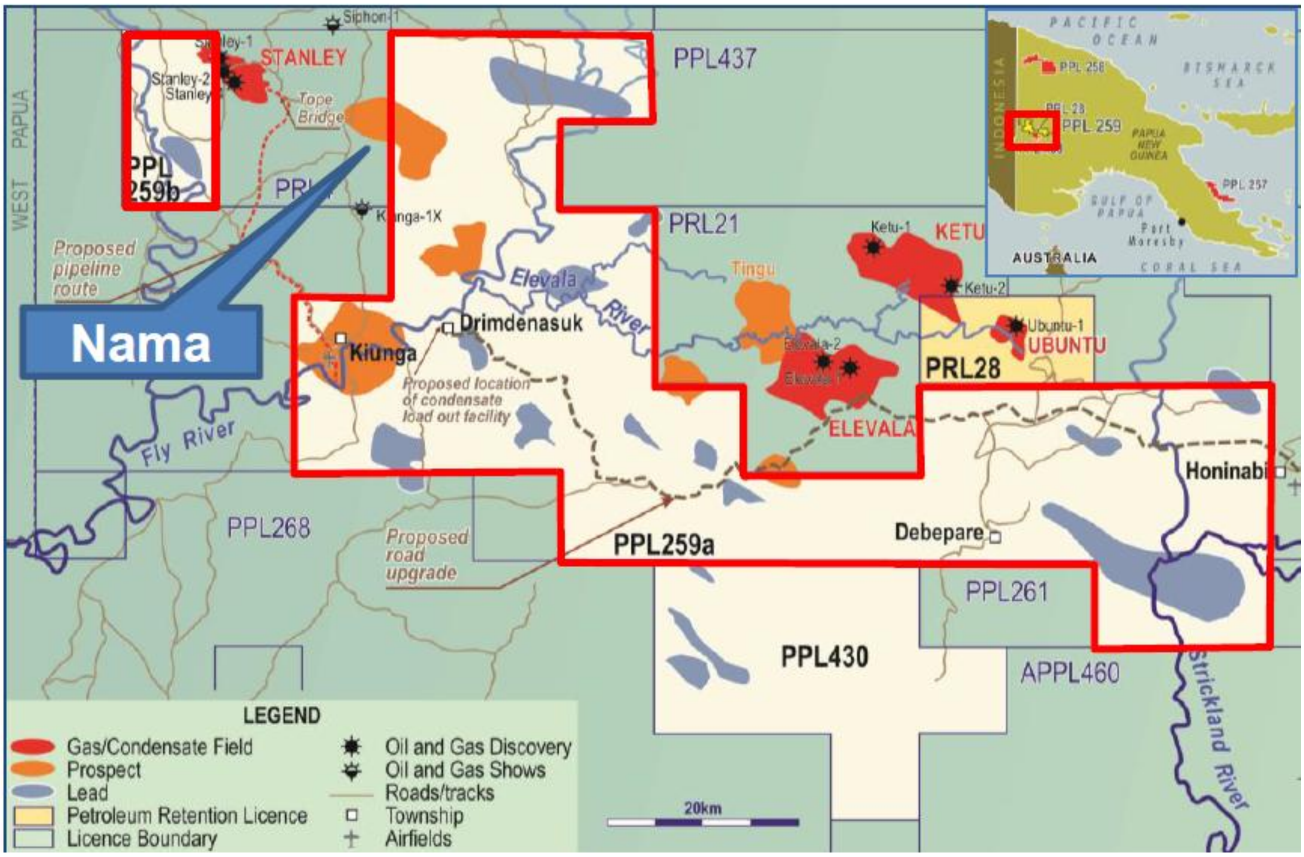


Figure 8-12 PPL 259 Block Location and Prospects

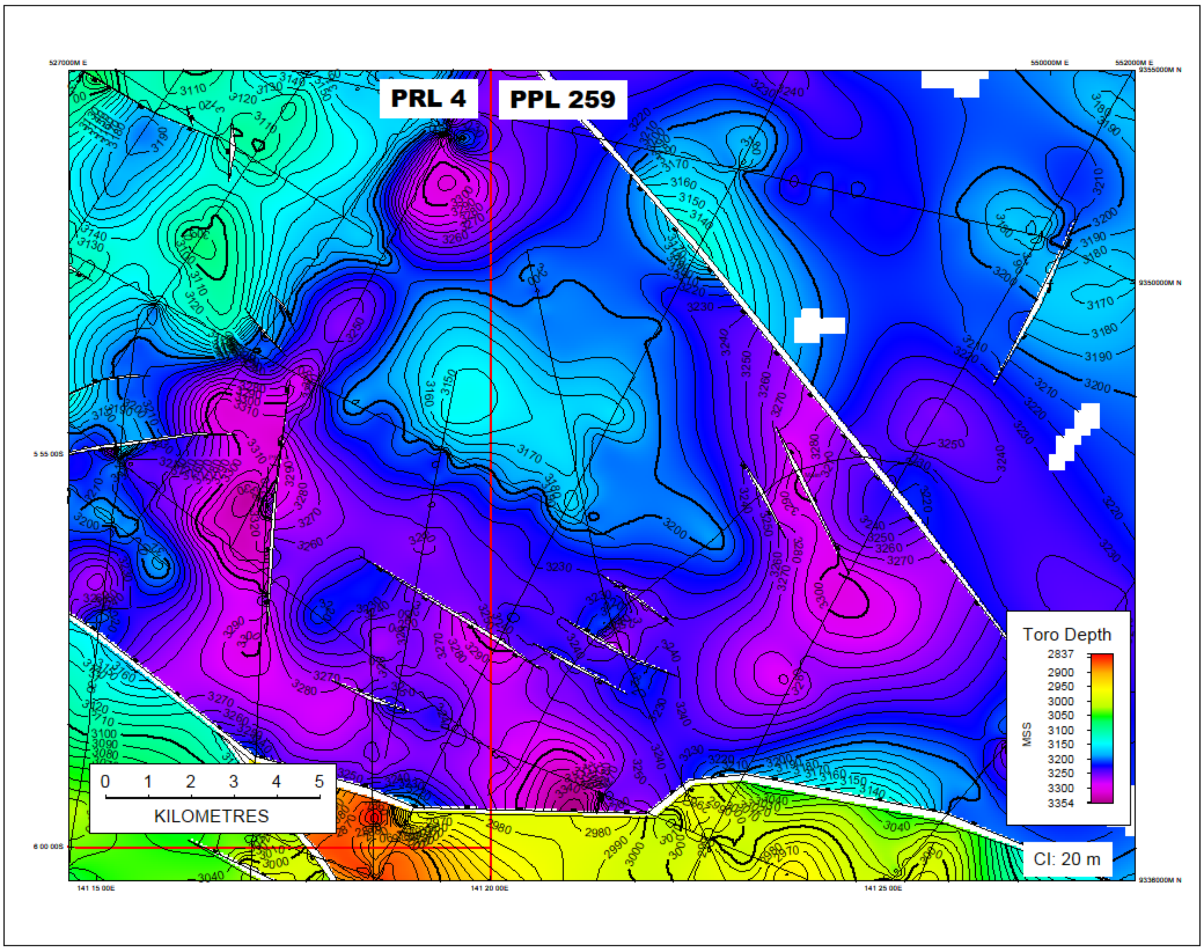


Figure 8-13 PPL 259 Nama Prospect Toro Depth Structure Map

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.

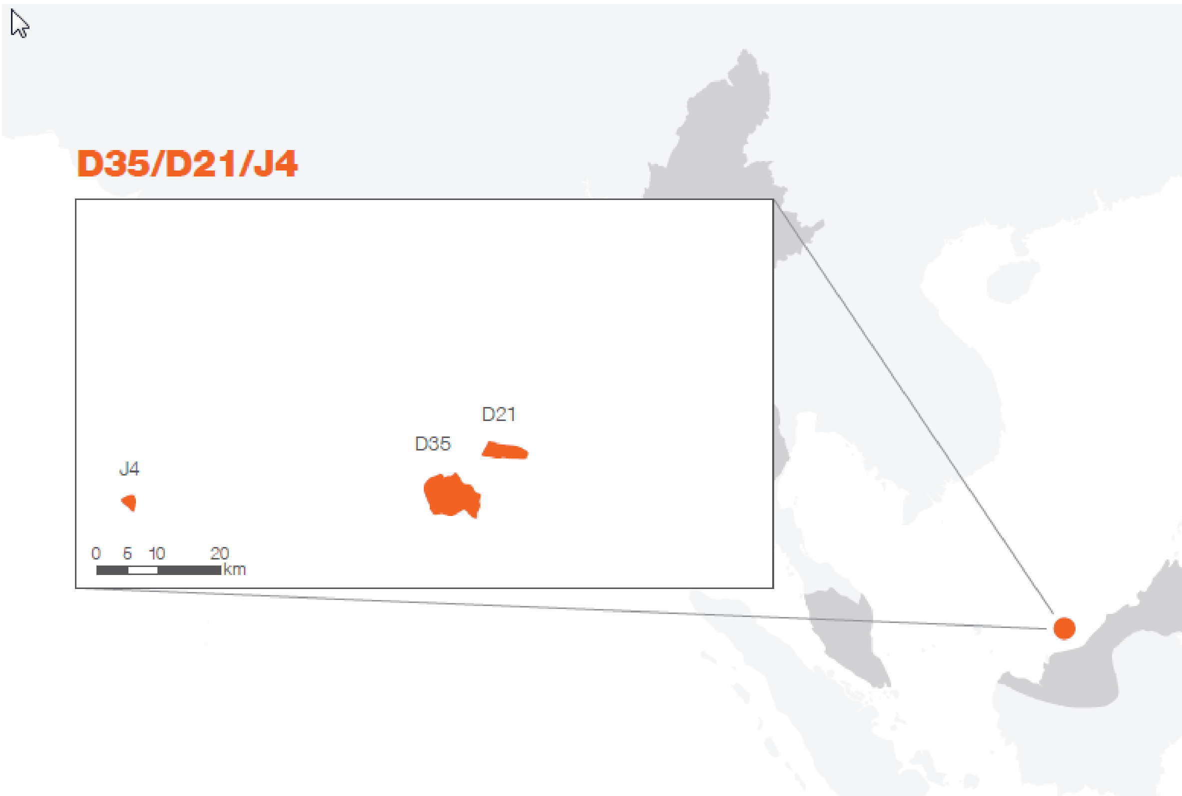


Figure 9-1 Location Map – Malaysian Fields, offshore Sarawak

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.

ROC's estimates are based on its own feasibility study of the fields or development area. Hence, the estimates presented herein should not be construed as being estimates supported or endorsed 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.

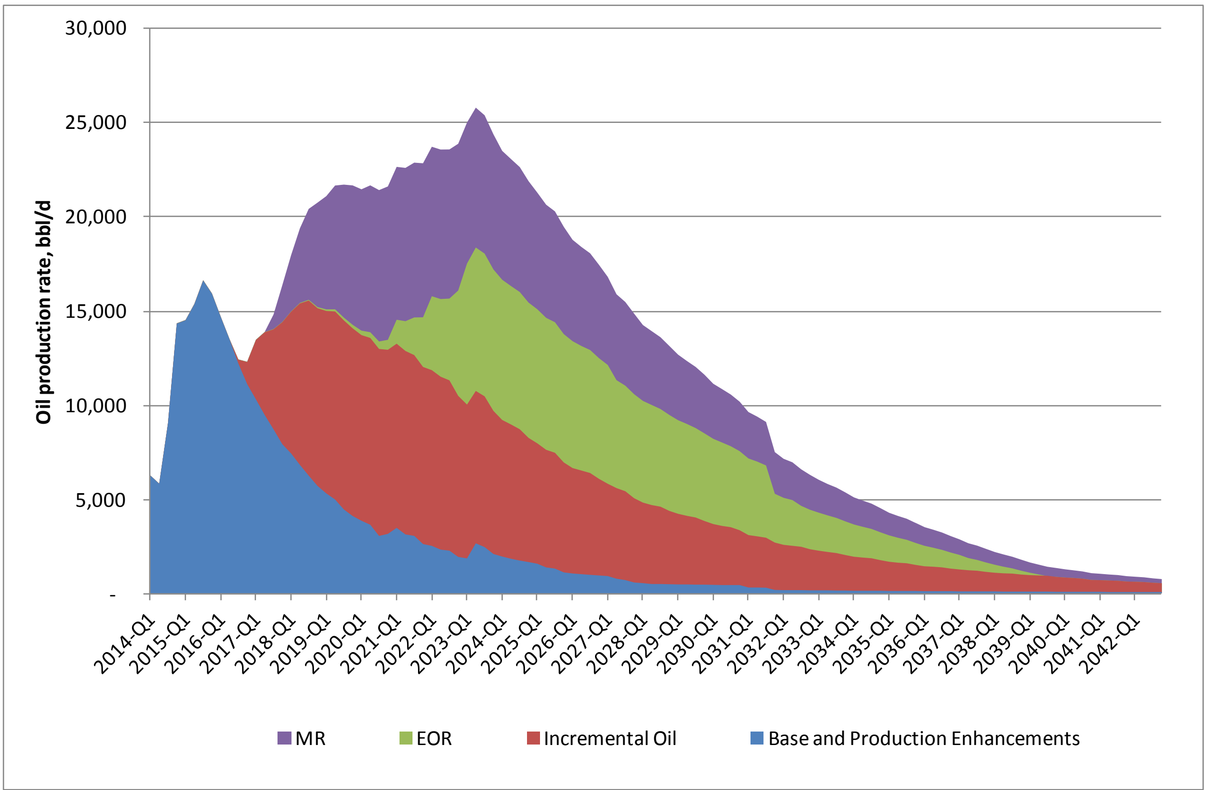


Figure 9-2 Gross oil production forecast, D35/J4/D21- Roc estimates

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

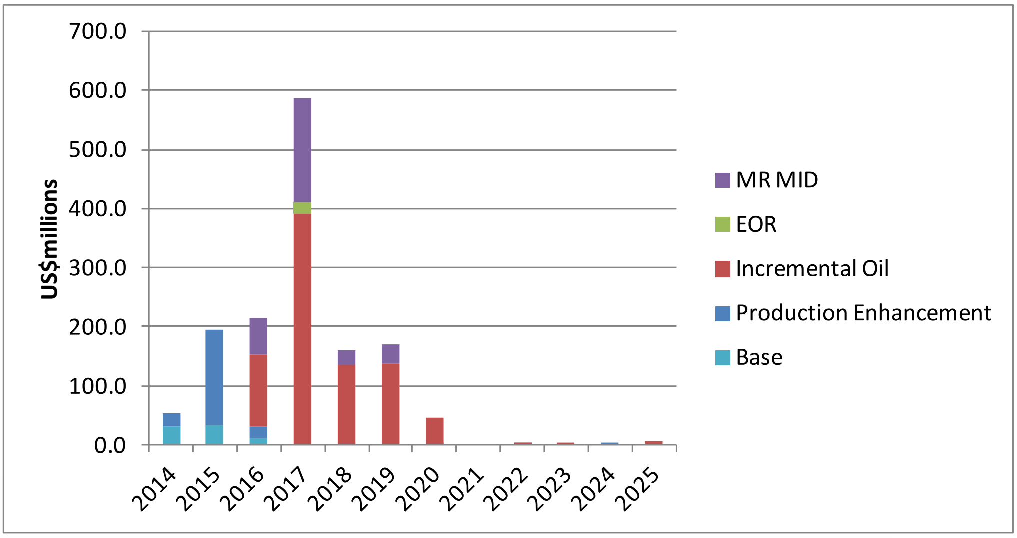


Figure 9-3 D35/D21/J4 Gross Capex Phasing – Roc estimates

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.

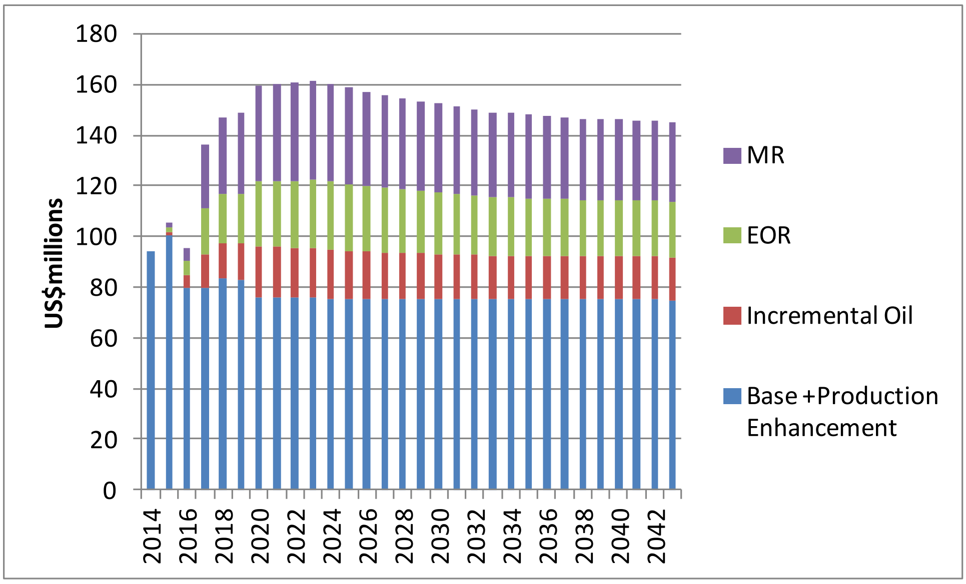


Figure 9-4 D35/D21/J4 Gross Opex Phasing – Roc estimates

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.

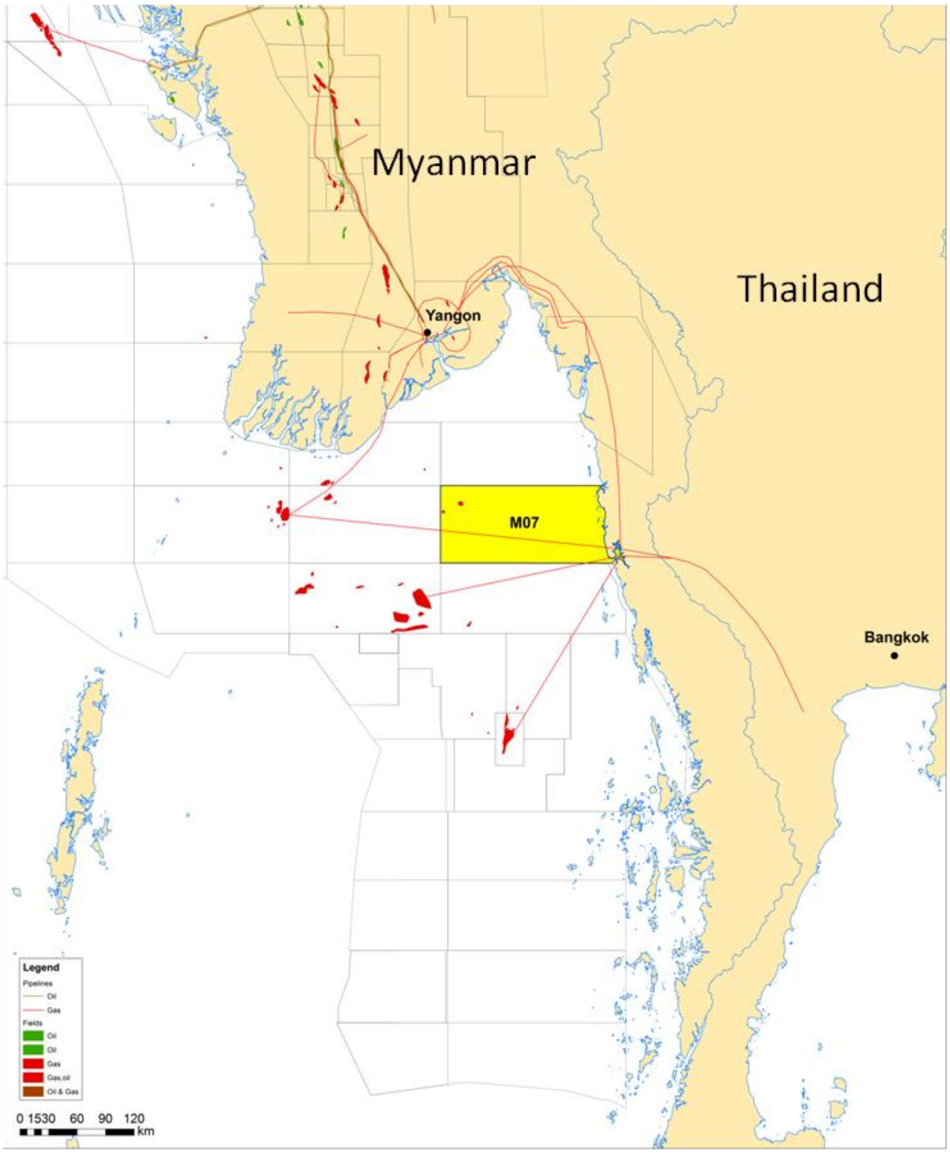


Figure 10-1 Myanmar Block M7 Location Map

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.

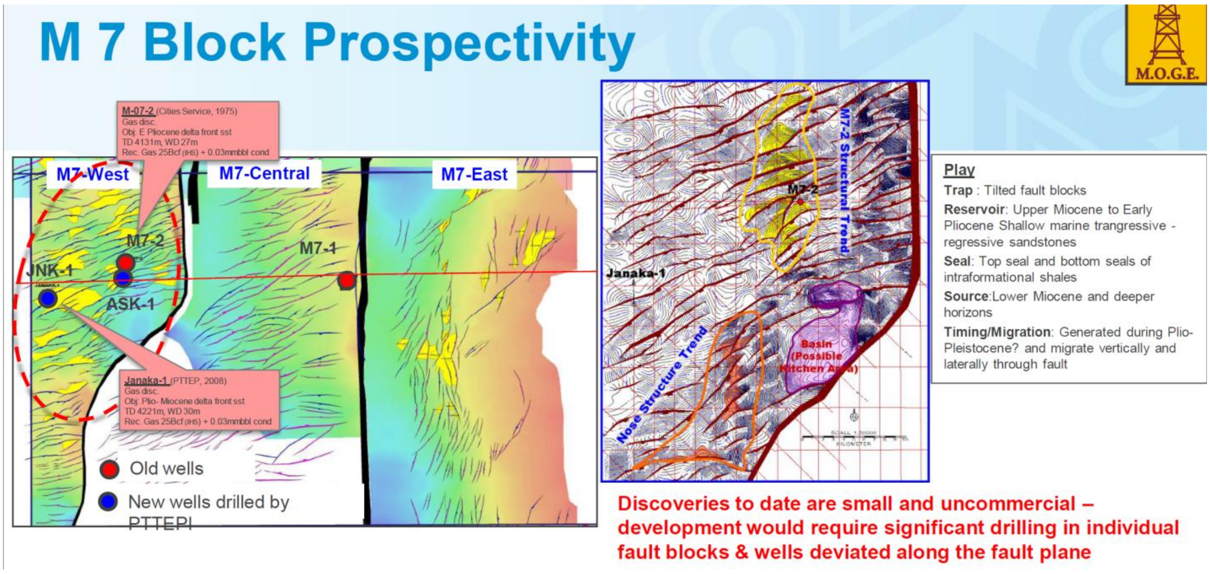


Figure 10-2 M7 Block Prospectivity

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 Grant Samuel and Associates Pty Limited (Grant Samuel) acting as the Independent Expert. RISC Operations Pty Ltd (RISC) acknowledges that Grant Samuel and the Directors of Roc Oil Company Limited (Roc) will use and place reliance on this Report in evaluating the proposed merger with Horizon Oil Limited (Horizon).

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 Roc 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 Roc and Grant Samuel and confirms that there is no conflict of interest with any party involved in the assignment;
- Under the terms of engagement between RISC and Grant Samuel for the provision of this report RISC will receive a fee, based on time expended and our current standard terms and conditions, payable by Roc. The payment of this fee is not contingent on the outcome of any transaction between, Horizon, Roc and other party;
- The Directors and staff of RISC involved in the preparation of this report hold no interest in 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 Grant Samuel, 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 Appendix 2 to the Independent Expert's Report prepared by Grant Samuel & Associates Pty Limited for Roc Oil Company 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

Appendix 3

Selection of Discount Rate

1 Overview

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

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

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

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

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

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

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

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

- the CAPM theory is based on expectations but uses historical data as a proxy. The future is not necessarily the same as the past;
- the measurement of historical data such as risk premia and beta factors is subject to very high levels of statistical error. Measurements vary widely depending on factors such as source, time period and sampling frequency;
- the measurement of beta is often based on comparisons with other companies. None of these companies is likely to be directly comparable to the entity for which the discount rate is being calculated and may operate in widely varying markets;

- parameters such as the debt/equity ratio and risk premium are based on subjective judgements; and
- there is not unanimous agreement as to how the model should adjust for factors such as taxation. The CAPM was developed in the context of a "classical" tax system. Australia's system of dividend imputation has a significant impact on the measurement of net returns to investors.

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

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

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

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

2 Definition and Limitations of the CAPM and WACC

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

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

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

Systematic risk is affected by the following factors:

- financial leverage: additional debt will increase the impact of changes in returns on underlying assets and therefore increase systematic risk;
- cyclicality of revenue: projects and companies with cyclical revenues will generally be subject to greater systematic risk than those with non-cyclical revenues; and
- operating leverage: projects and companies with greater proportions of fixed costs in their cost structure will generally be subject to more systematic risk than those with lesser proportions of fixed costs.

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

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

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

Where:

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

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

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

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

Where:

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

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

- **Risk Free Rate**

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

  The ten year bond rate is a widely used and accepted benchmark for the risk free rate. Where the forecast period exceeds ten years, an issue arises as to the appropriate bond to use. While longer term bond rates are available, the ten year bond market is the deepest long term bond market in Australia and is a widely used and recognised benchmark. There is a very limited market for bonds of more than ten years. In the United States, there are deeper markets for longer term bonds. The 30 year bond rate is a widely used benchmark. However, long term rates accentuate the distortions of the yield curve on cash flows in early years. In any event, a single long term bond rate matching the term of the cash flows is no more theoretically correct than using a ten year rate. More importantly, the ten year rate is the standard benchmark used in practice.

- **Market Risk Premium**

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

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

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

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

- **Beta Factor**

The beta factor is a measure of the expected covariance (i.e. volatility and correlation of returns) between the return on an investment and the return from the market as a whole. The expected beta factor cannot be observed. The conventional practice is to calculate an historical beta from past share price data and use it as a proxy for the future but it must be recognised that the expected beta is not necessarily the same as the historical beta. A company's relative risk does change over time.

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

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

- over the last three years ROC's beta as measured by SIRCA Limited ("SIRCA") has varied between 0.99 and 1.57 and was measured at 1.57 at 31 March 2014; and
- the standard error of SIRCA's estimate of ROC's beta has generally been in the order of 0.53 meaning that for a beta of, say, 1.57 even at a 68% confidence level, the range is 1.04 to 2.10.

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

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

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

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

- **Debt/Equity Mix**

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

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

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

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

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

- **Specific Risk**

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

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

3 Calculation of WACC

3.1 Cost of Equity Capital

The cost of equity capital has been estimated by reference to the CAPM. Grant Samuel has adopted a cost of equity capital in the range 9.7-10.3%.

- **Risk Free Rate**

  Grant Samuel has adopted a risk free rate of 2.5%. The risk free rate approximates the current yield to maturity on ten year United States Government bonds.

- **Market Risk Premium**

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

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

- **Beta Factor**

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

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

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

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

Equity Beta Factors for Selected Listed Upstream Oil and Gas Companies

Company	Market Capital-isation[5] (millions)	Monthly Observations over 5 years (Barra)[6]	Monthly Observations over 4 years			Weekly Observations over 2 years	
			SIRCA[7]	Bloomberg[8]		Bloomberg	
				Local	MSCI[9]	Local	MSCI
Australia							
ROC	**A$313**		**1.57**	**1.24**	**1.02**	**0.96**	**0.65**
Horizon	**A$482**		**2.18**	**1.70**	**1.59**	**0.92**	**0.70**
Production, Exploration and Development							
AWE	A$988		1.64	1.17	1.12	1.21	1.12
Senex Energy	A$828		1.73	1.28	1.38	1.48	1.13
Drillsearch	A$633		2.03	1.33	1.38	1.33	0.66
Cue Energy	A$80		1.57	0.84	0.79	0.87	0.59
Exploration and Development							
Karoon Gas	A$852		2.63	2.07	2.31	2.12	1.64
Buru Energy	A$336		0.20	0.30	0.46	1.12	1.01
Sino Gas & Energy	A$222		1.94	1.75	1.96	0.57	0.96
Cooper Energy	A$166		1.41	1.03	1.09	0.92	0.99
Tap Oil	A$108		1.73	1.47	1.41	0.88	0.78
Kina Petroleum[10]	A$91		na[11]	na	na	0.62	0.67

5 Based on share prices as at 12 June 2014 except for ROC and Horizon which are based on share prices as at 23 April 2014 (the last trading day prior to the announcement of the Merger).

6 Barra, Inc. ("Barra") beta factors calculated as at 30 April 2014 over a period of 60 months using ordinary least squares regression or the Scholes-Williams technique (including lag) where the stock is thinly traded.

7 The Australian beta factors calculated by SIRCA as at 31 March 2014 over a period of 48 months using ordinary least squares regression or the Scholes-Williams technique where the stock is thinly traded (i.e. for Cue Energy).

8 Bloomberg betas have been calculated up to 12 June 2014. Grant Samuel understands that betas estimated by Bloomberg are not calculated strictly in conformity with accepted theoretical approaches to the estimation of betas (i.e. they are based on regressing total returns rather than the excess return over the risk free rate). However, in Grant Samuel's view the Bloomberg beta estimates can still provide a useful insight into the systematic risks associated with companies and industries. The figures used are the Bloomberg "adjusted" betas.

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

Equity Beta Factors for Selected Listed Upstream Oil and Gas Companies							
Company	Market Capital-isation (millions)	Monthly Observations over 5 years (Barra)	Monthly Observations over 4 years			Weekly Observations over 2 years	
			SIRCA	Bloomberg		Bloomberg	
				Local	MSCI	Local	MSCI
International							
Production, Exploration and Development							
PT Medco Energi	IR10,980,427	0.88		0.62	0.72	0.63	0.44
Salamander Energy	£351	0.31		0.97	0.97	0.81	0.74
KrisEnergy[10]	S$853	na		na	na	na	na
RH Petrogas	S$661	0.90		1.00	1.02	0.84	0.57
PT Energi Mega	IR4,062,470	1.30		1.92	1.50	1.27	0.55
Exploration and Development							
Rex International[10]	S$717	na		na	na	na	na

Source: SIRCA, Barra, Bloomberg

In Grant Samuel's view, it is not clear that beta calculations based on share market data for the last two year period provide reliable estimates of expected systematic riskiness. Over the last two years, energy companies (including upstream oil and gas companies) have generally underperformed broader measures of equity market performance (increasing by less than the overall market) suggesting a beta of less than 1. In Grant Samuel's view this is potentially misleading. To the extent that the underperformance of energy companies reflects a one-off shift, the calculated betas may reflect a specific risk factor rather than systematic risk. Therefore, two year betas (in particular) may be understated. Grant Samuel has placed more reliance on the betas observed over a four year period.

In relation to the beta estimates:

- the beta estimates suggest that upstream oil and gas companies with investments in Australia and the Asia Pacific region generally have betas over 1.0 (indicating more systematic risk than the overall market);
- Cue Energy is relatively thinly traded and therefore betas calculated using the ordinary least squares regression technique may be less reliable. SIRCA also provides betas based on the Scholes-Williams technique which may compensate for the effects of thin trading (1.57 for Cue Energy). Bloomberg makes no such adjustment and therefore its betas for Cue Energy may be less reliable;
- Buru Energy Limited ("Buru") was thinly traded until January 2012, when the share price was rerated following the major discovery of the Ungani oilfield in offshore Western Australia. Therefore, its four year betas are not considered reliable;
- PT Medco Energi Internasional Tbk ("PT Medco Energi") is engaged in both upstream and downstream activities and therefore it is not directly comparable to either ROC or Horizon;
- upstream oil and gas companies which have substantial producing assets generally have lower betas than companies which do not have producing. Bloomberg Four Year Monthly MSCI betas for companies with producing assets in the range 1.1-1.4 (ASX) (excluding Cue Energy) and 1.0-1.5 (international) (excluding PT Medco Energi) whereas betas for ASX listed companies which do not have producing assets are in the range 1.1-2.3 (excluding Buru). No betas have been observed for overseas listed oil and gas companies that do not have producing assets; and
- betas are inextricably linked to gearing. Horizon's Bloomberg Four Year Monthly MSCI beta of 1.59 is substantially higher than that of ROC (1.02), likely as a result of its gearing. The companies that are most comparable to ROC and Horizon (AWE, Senex Energy and Drillsearch) have comparatively low levels of gearing.

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

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

11 na = not available

- **Calculation**

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

Low			**High**		
Re	=	*Rf + Beta (Rm-Rf)*	*Re*	=	*Rf + Beta (Rm-Rf)*
	=	*2.5% + (1.2 x 6.0%)*		=	*2.5% + (1.3 x 6.0%)*
	=	***9.7%***		**=**	***10.3%***

3.2 Cost of Debt

A cost of debt of 4.0% has been adopted having regard to the margins reflected in ROC and Horizon's existing debt facilities over the London Interbank Rate ("LIBOR") (around 3.5%)[12]. Grant Samuel believes that this would be a reasonable estimate of an average interest rate, including a margin that would match the duration of the cash flows assuming that the operations were funded with a mixture of short term and long term debt.

3.3 Debt/Equity Mix

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

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

Gearing Levels for Selected Listed Upstream Oil and Gas Companies

	Net Debt/(Net Debt + Market Capitalisation)							
	Financial Year Ended					Current[13]	*4 Year Average*	*5 Year Average*
	Historical 5	Historical 4	Historical 3	Historical 2	Historical 1			
Australia								
ROC	**(4.3%)**	**(11.7%)**	**(17.5%)**	**(22.2%)**	**(27.7%)**	**(28.9%)**	**(19.8%)**	**(16.7%)**
Horizon	**6.2%**	**2.2%**	**13.0%**	**21.1%**	**33.2%**	**28.8%**	**17.4%**	**15.1%**
Production, Exploration and Development								
AWE	(25.4%)	(7.5%)	(32.4%)	7.5%	(12.6%)	(8.3%)	(11.2%)	(14.1%)
Senex Energy	(22.8%)	(2.9%)	(18.3%)	(23.3%)	(13.8%)	(12.4%)	(14.6%)	(16.2%)
Drillsearch	(8.1%)	(16.4%)	(15.9%)	5.4%	11.7%	10.7%	(3.8%)	(4.7%)
Cue Energy[14]	0.4%	(16.9%)	(49.2%)	(83.3%)	(113.8%)	(166.4%)	(65.8%)	(52.5%)
Exploration and Development								
Karoon Gas	(11.7%)	(25.0%)	(36.4%)	(24.1%)	(19.4%)	(1.0%)	(26.2%)	(23.3%)
Buru Energy	nmf[15]	(61.4%)	(11.6%)	(6.8%)	(19.7%)	(34.5%)	(24.9%)	(24.9%)
Sino Gas & Energy	30.4%	(15.5%)	(12.4%)	(5.6%)	(28.2%)	(40.7%)	(15.4%)	(6.3%)
Cooper Energy	(172.2%)	(27.0%)	(199.0%)	(29.5%)	(32.6%)	(32.2%)	(72.0%)	(92.0%)
Tap Oil	(48.1%)	(97.8%)	(132.9%)	(177.1%)	(55.2%)	6.4%	(115.7%)	(102.2%)
Kina Petroleum[16]	na	na	nmf	(22.7%)	(7.5%)	(8.5%)	(15.1%)	(15.1%)
International								
Production, Exploration and Development								
PT Medco Energi	30.8%	36.6%	30.8%	50.9%	50.4%	37.1%	42.2%	39.9%
Salamander Energy	14.8%	22.0%	31.1%	18.5%	4.5%	29.3%	19.0%	18.2%
KrisEnergy[16]	na	na	na	na	(8.8%)	(14.0%)	(8.8%)	(8.8%)
RH Petrogas	(12.6%)	16.1%	25.2%	4.9%	(1.5%)	2.5%	11.2%	6.4%
PT Energi Mega	61.9%	36.3%	46.0%	50.6%	35.3%	58.3%	42.0%	46.0%
Exploration and Development								
Rex International[16]	na	na	na	na	(21.1%)	(16.7%)	(21.1%)	(21.1%)

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

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12 At 31 December 2013 ROC's undrawn debt facility had an effective interest rate of 3.7% (based on a fixed margin over LIBOR) and Horizon's reserves based debt facility was based on LIBOR and a weighted average margin of 3.5%.

13 Current gearing levels are based on the most recent balance sheet information and on sharemarket prices as at 12 June 2014, except for ROC and Horizon which are based on share prices as at 23 April 2014 (the trading day prior to the announcement of the Merger).

14 Cue Energy's relatively high level of cash in recent years reflects the scale of its production relative to exploration in FY13.

15 nmf = not meaningful

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

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

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

3.4 WACC

On the basis of the parameters outlined and assuming a corporate tax rate of 40%[17], the nominal WACC is calculated to be in the range 8.2-9.5%.

Low

WACC = (Re x E/V) + (Rd x (1-t) x D/V)
= (9.7% x 80%) + (4.0% x 70% x 20%)
= 8.2%

High

WACC = (Re x E/V) + (Rd x (1-t) x D/V)
= (10.3% x 90%) + (4.0% x 70% x 10%)
= 9.5%

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

- anecdotal information suggests that equity investors have repriced risk since the global financial crisis in 2007 and that acquirers are pricing offers on the basis of hurdle rates above those implied by theoretical models. However, this has yet to be translated into the measures of market risk premium (at least those based on longer term historical data). In this regard, an increase in the market risk premium of 1% (i.e. from 6% to 7%) would increase the calculated WACC range to 9.2-10.7%;
- global interest rates, including long term bond rates, are at low levels by comparison with historical norms reflecting the liquidity still being pumped into many advanced economies to stimulate economic activity. Effective real interest rates remain low. Grant Samuel does not believe this position is sustainable and the risk is clearly towards a rise in bond yields. Conceptually, the interest rates used to calculate the discount rate should recognise this expectation (i.e. they should be forecast for each future period) but for practical ease market practice is that a single average rate based on the long term bond rate is generally adopted for valuation purposes. Some academics/valuation practitioners consider it to be inappropriate to add a "normal" market risk premium (e.g. 6%) to a temporarily depressed bond yield and therefore advocate that a "normalised" risk free rate should be used. On this basis, an increase in the risk free rate to (say) 4% would increase the calculated WACC range to 9.6-11.0%; and
- analysis of research reports on ROC and Horizon indicates that brokers are currently adopting WACCs in the range 9-10.4% with a median of 10.0%.

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

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

4 Dividend Imputation

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

Under Australia's dividend imputation system, domestic equity investors now receive a taxation credit (franking credit) for any tax paid by a company. The franking credit attaches to any dividends paid out by a company and the franking credit offsets personal tax. To the extent the investor can utilise the franking credit to offset personal tax, then the corporate tax is not a real impost. It is best considered as a withholding tax for personal taxes. It can therefore be argued that the benefit of dividend imputation should be added into any analysis of value.

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

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

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

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

Appendix 4

Market Evidence

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

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

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

Company	Market Capital-isation[1] (millions)	Reserves and Resources (mmboe)		Multiple of Reserves and Resources (US$/mmboe)		Production (mmboe)		Multiple of Production (US$/mmboe)	
		2P[2]	2P+2C[3]	2P[4]	2P+2C[5]	Historical	Forecast	Historical	Forecast
Australia									
Production, Exploration and Development									
AWE	A$988	91.1	188.6	9.4	4.6	5.0	5.3	172.0	163.8
Senex Energy	A$828	37.4	408.2	18.3	1.7	1.2	1.4	564.2	487.6
Drillsearch	A$633	29.1	49.1	22.9	13.6	1.1	3.2	605.5	211.5
Cue Energy	A$80	5.3	24.8	5.4	1.1	0.9	0.8	31.6	35.5
Exploration and Development									
Karoon Gas	A$852	-	135.0	nmf[6]	5.9	-	-	nmf	nmf
Buru Energy	A$336	9.9	9.9	23.4	23.4	-	0.6	nmf	385.7
Sino	A$222	51.9	203.6	2.0	0.5	-	-	nmf	nmf
Cooper Energy	A$166	2.2	19.2	25.6	2.9	-	0.6	nmf	92.1
Tap Oil	A$108	6.1	28.7	17.8	3.8	-	1.6	nmf	67.8
Kina	A$91	-	25.9	nmf	3.0	-	-	nmf	nmf
International									
Production, Exploration and Development									
PT Medco Energi	IR10,980,427	294.0	452.0	4.4	2.8	20.5	19.7[7]	62.6	65.1
Salamander Energy	£383	65.3	186.3	12.8	4.5	5.2	5.3	161.4	158.3
KrisEnergy	S$769	32.3	100.9	18.5	5.9	7.1	na[8]	84.4	na
RH Petrogas	S$665	11.9	82.7	45.7	6.6	1.5	1.6[7]	362.3	331.4
PT Energi Mega	IR4,062,470	230.0	230.0	2.8	2.8	18.0	na	35.4	na
Exploration and Development									
Rex International	S$777	4.6	26.1	87.4	15.4	-	-	nmf	nmf

Source: Grant Samuel analysis[9]

1 Market capitalisation based on sharemarket prices as at 12 June 2014.
2 2P = proven and probable reserves
3 2C = contingent resources
4 Represents gross capitalisation (that is, the sum of the market capitalisation adjusted for minorities, plus borrowings less cash as at the latest balance date) divided by 2P reserves.
5 Represents gross capitalisation dividend by the sum of 2P reserves and 2C contingent resources.
6 nmf = not meaningful
7 Broker estimate
8 na = not available
9 Grant Samuel analysis based on data obtained from IRESS, Capital IQ, company announcements and, in the absence of company published financial forecasts, brokers' reports. Where company financial forecasts are not available, the median of the financial forecasts prepared by a range of brokers has generally been used to derive relevant forecast value parameters. The source, date and number of broker reports utilised for each company depends on analyst coverage, availability and recent corporate activity.

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

- are relatively imprecise valuation metrics and are limited in that they are calculated on publicly available information;
- are based on sharemarket prices as at 12 June 2014 and do not reflect a premium for control.

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

A brief description of each company is set out below:

AWE Limited

AWE is an ASX listed energy company focused on upstream oil and gas production, exploration and development. It has interests in producing assets in Australia, New Zealand and the United States, which it expects will produce 5-5.5 mmboe in FY14. It also has interests in development/appraisal/ exploration assets in Australia, New Zealand, Indonesia and the United States. As at 31 March 2014, it had 91.1mmboe of 2P reserves and 97.5mmboe of 2C resources.

Senex Energy Limited

Senex Energy Limited ("Senex") is an ASX listed energy company focused on upstream oil and gas production, exploration and development in Australia's Cooper, Eromanga and Surat Basins, as well as coal seam gas acreage in Queensland. It expects to produce 1.4 mmboe of oil in FY14. As at 31 March 2014, Senex had 37.4mmboe of 2P reserves and 370.8mmboe of 2C resources.

Drillsearch Limited

Drillsearch Limited ("Drillsearch") is an ASX listed energy company focused on upstream oil and gas production, exploration and development in Australia's Cooper Basin. It expects to produce 3-3.3mmboe in FY14. As at 31 March 2014, it had 29.1mmboe of 2P reserves and 20mmboe of 2C resources. On 28 May 2014, Drillsearch announced the acquisition of Ambassador Oil and Gas Limited ("Ambassador") for approximately $33 million, consolidating Drillsearch's 80% interest in PEL 101 in the Northern Cooper basin with Ambassador's adjacent 47.5% interest in PEL570. The multiples have not been adjusted for the impact of the transaction.

Cue Energy limited

Cue Energy is an ASX listed energy company focused on upstream oil and gas production, exploration and development. It has interests in producing assets in the Taranaki Basin in New Zealand and offshore East Java in Indonesia and interests in development/appraisal/exploration assets in the Carnarvon Basin in Australia, Taranaki Basin in New Zealand, Kutei Basin in Indonesia and Papuan Basin in Papua New Guinea. It produced approximately 0.9mmboe in the year to 31 December 2013 and expects to produce around 0.8mmboe in 2014. As at 31 December 2012, Cue Energy reported 5.2mmbbl of 2P reserves and 19.5mmboe of 2C resources.

Karoon Gas Australia Ltd

Karoon Gas is an ASX listed energy company focused on upstream oil and gas exploration and development. It does not have producing assets. It has interests in development/appraisal/exploration assets in the Browse and Carnarvon basins in Australia and in Peru and Brazil. In August 2013, Karoon Gas reported 135mmboe (net) of 2C resources. On 2 June 2014, it announced the sale of its 40% interest in Browse Basin permits WA-315-P and WA-398-P to Origin Energy for a US$600 million upfront cash payment and deferred cash payments of up to US$200 million. The multiples are calculated prior to the impact of the transaction.

Buru Energy Limited

Buru Energy Limited ("Buru Energy") is an ASX listed energy company focused on exploring and developing oil and gas resources in the Canning Basin and in the southwest Kimberley region of Western Australia. Production at the Ungani oilfield has recently commenced and is ramping up throughout FY14 and FY15. The Ungani oilfield is estimated to have 10mmboe of 2P reserves. No 2C resource has been certified but RISC Operations Pty Ltd has concluded that the best estimate (P50) for the Laurel Formation tight gas accumulation is that it contains, net to Buru Energy, 47tcf of gas and 1,177 million bbls of condensate (excluding hydrocarbon liquids). The significant potential of this resource is reflected in Buru Energy's relatively high multiple.

Sino Gas & Energy Holdings

Sino is an ASX listed energy company focused on exploring and developing Chinese unconventional gas assets. Sino does not currently have producing assets. It holds a 49% interest in Sino Gas & Energy Limited ("SGE") through the strategic partnership with MIE Holdings Corporation. SGE is the operator of the Linxing and Sanjiaobei Production Sharing Contracts in the Ordos Basin, Shanxi province. As at 31 March 2014, Sino reported 51.9mmbbl of 2P reserves and 151.7mmboe of 2C resources.

Cooper Energy Limited

Cooper Energy is an ASX listed energy company focused on upstream oil and gas exploration and development. It has interests in assets which have recently commenced production in the Cooper Basin and Indonesia and interests in development/appraisal/exploration assets in the Cooper Basin, Otway Basin, Gippsland Basin and Indonesia. In FY14, it is expected to produce around 0.6mmbl per annum. As at 31 March 2014, Cooper Energy had 2.2mmboe of 2P reserves and 17.0mmboe of 2C resources.

Tap Oil Limited

Tap Oil is an ASX listed energy company focused on upstream oil and gas exploration and development. It has interests in development/appraisal/exploration assets in the Carnarvon Basin and Otway Basin in Australia, Manora Oil Development in the Northern Gulf of Thailand and Myanmar. Although it is not currently producing, production at the Manora Oil Development in Thailand is expected to commence late in the September quarter of 2014 at around 1.6mmboe per annum. As at 31 March 2014, Tap Oil had 6.1mmboe of 2P reserves and 22.6mmboe of 2C resources.

Kina Petroleum Limited

Kina Petroleum Limited ("Kina") is an energy company focused on upstream oil and gas exploration and development in Papua New Guinea. It was listed on the ASX in December 2011. Kina does not currently have producing assets. Kina has interests in seven onshore Petroleum Prospecting Licences and a 15% interest in PRL 21, which contains two wet gas discoveries, Elevala and Ketu, and Tingu. Initially awarded 20% of PRL 21, Kina divested 5% of PRL21 in 2011 for US$5.5 million. As at 31 December 2013, it reported 25.9mmboe of 2C resources within PRL 21 (Elevala and Ketu) (net to Kina).

PT Medco Energi Internasional Tbk

PT Medco Energi Internasional Tbk ("Medco Energi") is an integrated energy company listed on the Jakarta Stock Exchange. Its business comprises upstream oil and gas production, exploration and development operations and downstream operations (e.g. power generation, LPG processing, diesel marketing, storage and transportation, gas transportation and coal mining). It has interests in oil and gas assets in Indonesia, Libya, Yeman, Oman and the United States. As at 31 December 2012, it had 294.0mmboe of 2P reserves and 158mmboe of 2C resources. In the 12 months to 31 December 2013, Medco Energi produced 20.5mmboe of oil and gas.

Salmander Energy plc

Salamander Energy plc ("Salamander") is a London Stock Exchange listed energy company focused on upstream oil and gas production, exploration and development. It has interests in development/appraisal/exploration assets in onshore Korat and offshore Bualuang, Thailand, Melaka Strait, Malaysia and Greater Kerendan, Indonesia. As at 31 December 2013, it had 65.3mmboe of 2P reserves and 121.0mmboe of 2C resources. Production for the year ended 31 December 2013 from its operations in Thailand was 5.2mmboe and Salamander expects to produce 5.3mmboe in 2014.

KrisEnergy Limited

KrisEnergy Limited ("KrisEnergy") is an energy company focused predominantly on upstream oil and gas production, exploration and development. It was listed on the Singapore Exchange in July 2013. It has an extensive portfolio of licences throughout Asia, including in Bangladesh, Cambodia, Indonesia, Thailand and Vietnam. As at 31 December 2013, it reported 32.3mmboe of 2P reserves and 68.6mmboe of 2C resources. KrisEnergy also has two offshore producing assets in the Gulf of Thailand and the onshore Bangora gas field in Bangladesh which produced 7.1mmboe in the year to 31 December 2013.

RH Petrogas Limited

RH Petrogas Limited ("RH Petrogas") is a Singapore Exchange listed energy company focused on upstream oil and gas production, exploration and development. It has interests in assets primarily in Indonesia as well as in China and Malaysia. In the 12 months to 31 December 2013, it produced 1.5mmboe of oil and gas and production is expected to increase further in FY14. As at 31 December 2013, RH Petrogas had 11.9mmboe of 2P reserves and 70.8mmboe of 2C resources.

PT Energi Mega Persada Tbk

PT Energi Mega Persada Tbk ("Energi Mega Persada") is a Jakarta Stock Exchange listed energy company focused on upstream oil and gas production, exploration and development throughout Indonesia (including Kangean Island, East Java province, Riau, Jambi, North Sumatra, East Kalimantan and West Java). It operates 12 oil, gas and coal bed methane assets with 2P reserves of 230mmboe. In the year to 31 December 2013, Energi Mega Persada produced 18.0mmboe of oil and gas.

Rex International Holding Limited

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