# MIRACH ENERGY LIMITED

**Competent Person's Report**
**Kampung Minyak, Indonesia**
**As of December 31, 2013**

McDaniel & Associates Consultants Ltd.

# MIRACH ENERGY LIMITED

**Competent Person's Report**
**Kampung Minyak, Indonesia**
**As of December 31, 2013**

**Prepared For:**

**Mirach Energy Limited**
**3902 Cosco Tower**
**183 Queen's Road Central**
**Hong Kong, China**

**Prepared By:**

**McDaniel & Associates Consultants Ltd.**
**2200, 255 – 5th Avenue SW**
**Calgary, Alberta**
**T2P 3G6**

**March 2014**

# MIRACH ENERGY LIMITED

## TABLE OF CONTENTS

## TABLES



## FIGURES

## APPENDIX – ADDITIONAL TABLES AND FIGURES

McDaniel & Associates Consultants Ltd.

March 18, 2014

**Mirach Energy Limited**
3902 Cosco Tower
183 Queen's Road Central
Hong Kong, China

Reference: **Mirach Energy Limited**
**Competent Person's Report as of December 31, 2013 for Kampung Minyak field in Indonesia**

Dear Sirs

Pursuant to your request, we have prepared an independent evaluation of the crude oil and natural gas contingent and prospective resources for the interests of Mirach Energy Limited ("Mirach") in the Kampung Minyak ("KM") Field in Indonesia as of December 31, 2013.

This Competent Person's Report ("CPR") was prepared for securities reporting, banking and financing, and corporate transactions. The contingent and prospective resources have been prepared in accordance with the 2007 SPE/WPC/AAPG/SPEE Petroleum Resource Management System ("PRMS"). McDaniel & Associates Consultants Ltd. ("McDaniel") previously evaluated this asset for Mirach as part of a CPR issued in March 2013 with an effective date of December 31, 2012.

This updated CPR was prepared during the period from February to March 2014 and was based on technical data to the end of December 2013. In preparing this report, we relied upon factual information including ownership, technical well and seismic data, contracts, and other relevant data supplied by Mirach. The extent and character of all factual information supplied were relied upon by us in preparing this report and has been accepted as represented. Mirach has provided McDaniel with written representation that no new data or information has been acquired between December 31, 2013 and the date of this report, which might materially impact our opinions in this report.

## 1 EXECUTIVE SUMMARY

Mirach has the following interest in the subject block in Indonesia as summarized in Table 1 below. A regional map showing the location of the Blocks is presented in Figure 1.

| Contract | Country | Operating Company | Mirach Interest | Status | Contract Expiry (1) | Area (sq.km) | Comment |
|---|---|---|---|---|---|---|---|
| Kampung Minyak KSO | Indonesia | Prisma Kampung Minyak | 100% | Production Enhancement | July 2026 | 45 | Producing |

(1) The contract expiry date shown does not include possible extension periods.

**Table 1 - Mirach Asset Summary**


**Figure 1 – Regional Location Map for the Kampung Minyak Block**

The Kampung Minyak KSO Contract came into effect on July 15, 2011 and is a production enhancement type contract covering a 15-year production period. Mirach is entitled to a share of the oil above a baseline oil forecast as defined in the contract. Both contingent and prospective resources have been assigned to the KM Field as part of this evaluation.

### 1.1 Contingent Resources

Contingent Resources have been assigned to the KM Block. A summary of Mirach's share of the resources estimates, as of December 31, 2013, is presented below:

| Crude Oil, Mbbl | Low Estimate (1C) | Best Estimate (2C) | High Estimate (3C) |
|---|---|---|---|
| Property Gross (1) | 601 | 2,623 | 5,813 |
| Company Gross (2) | 441 | 2,453 | 5,643 |
| Company Net (3) | 356 | 1,134 | 2,209 |

(1) Property gross resources include the baseline production
(2) Company gross resources are based on the Mirach working interest share of the property gross resources less the baseline production.
(3) Company Net resources are based on the Mirach share of Cost Oil and Profit Oil revenues.

**Table 2 – Mirach Contingent Resources Summary**

Contingent Resources were assigned to the KM Field, as it is still too early to be able to determine whether the proposed development plans will be economic. As more results become available and commerciality is confirmed it should be possible to reclassify some, or all, of these contingent resources as reserves.

### 1.2 Net Present Values of the Contingent Resources

Mirach's share of the net present values of the contingent resources based on forecast prices and costs as of December 31, 2013 were estimated to be as follows:

| | Net Present Values at December 31, 2013 (US$ M) (1) (2) Discounted At | | | | |
|---|---|---|---|---|---|
| | 0% | 5% | 10% | 15% | 20% |
| **Kampung Minyak** | | | | | |
| Low Estimate Case | 3,852 | 1,962 | 675 | (222) | (860) |
| Best Estimate Case | 24,707 | 16,451 | 11,089 | 7,489 | 5,003 |
| High Estimate Case | 59,711 | 40,718 | 28,676 | 20,701 | 15,227 |

(1) Based on forecast prices and costs at January 1, 2014 (see Section 3).
(2) The net present values may not necessarily represent the fair market value of the resources.

**Table 3 – Mirach Contingent Resources Net Present Value Summary**

### 1.3 Prospective Resources

Prospective Resources were assigned to the KM Block in Indonesia for the prospects identified by Mirach. A summary of the resource estimates, as of December 31, 2013, is presented in Table 4. A more detailed description of the prospective resources calculations is included in Section 4.8. The oil and condensate (or gas) initially in-place is shown in the first column on a property gross basis for illustrative purposes only and is by definition not a recoverable volume.

**Prospective Resources: Crude Oil and Condensate (MMbbl)**

| Prospect (1) | Property Gross (Unrisked) Initially In Place (Mean) | Low Estimate (P90) | Best Estimate (P50) | Mean | High Estimate (P10) | Prospect Geological Chance of Discovery (2) | Risked Mean Property Gross (3) | Company Gross (4) | Company Net (5) |
|---|---|---|---|---|---|---|---|---|---|
| **KM** | | | | | | | | | |
| Deep | *189* | 19.6 | 34.1 | 37.9 | 59.7 | 99.7% | 21.4 | 21.4 | 7.5 |
| **Total** (6) | ***189*** | **19.6** | **34.1** | **37.9** | **59.7** | | **21.4** | **21.4** | **7.5** |

**Prospective Resources: Natural Gas (Bcf)**

| Prospect (1) | Property Gross (Unrisked) Initially In Place (Mean) | Low Estimate (P90) | Best Estimate (P50) | Mean | High Estimate (P10) | Prospect Geological Chance of Discovery (2) | Risked Mean Property Gross (3) | Company Gross (4) | Company Net (5) |
|---|---|---|---|---|---|---|---|---|---|
| **KM** | | | | | | | | | |
| Deep | *124* | 14.8 | 31.7 | 42.5 | 84.1 | 99.7% | 12.8 | 12.8 | 3.49 |
| **Total** (6) | ***124*** | **14.8** | **31.7** | **42.5** | **84.1** | | **12.8** | **12.8** | **3.5** |

(1) Separate zones within each prospect were added probabilistically using monte-carlo simulation.
(2) The prospect geological chance of discovery is based on the success of any one of the prospect zones and assumes independence and consequently is not equivalent to the [Risked Mean]/[Unrisked Mean]
(3) Prospect risked mean resources are equal to the summed product of the unrisked mean resources for each zone multiplied by the geological chance of success of each zone.
(4) Company gross prospective resources are based on the working interest share of the property gross prospective resources
(5) Company Net resources are based on the Mirach share of Cost Oil and Profit Oil revenues.
(6) The total may appear to differ from the sum of the underlying assets due to rounding differences.

**Table 4 - Mirach Prospective Resources Summary**

The geological chance of discovery for the KM deep zones is extremely high at over 99 percent; this is based on the assumption that the chance of discovery of any one of the seven prospective zones is independent of the others and where dependencies do occur the chance will be reduced.

These estimates do not include the chance of commercial success, which is very difficult to determine at this stage. The net present value estimates listed in Section 1.4 include both the crude oil and natural gas volumes in Kampung Minyak.

### 1.4 Net Present Value of the Risked Mean Prospective Resources

The net present value of the risked mean prospective resources was based on future production and revenue analyses. A corporate summary of the net present values of Mirach's share of the prospective resources, based on forecast prices and costs as of December 31, 2013, is presented in Table 5. The total net present value of the risked mean resources at a 10 percent discount rate is estimated to be US $ 136 million.

| Prospect | Net Present Values at December 31, 2013 (US$ MM)(1)(2) Discounted At | | | | |
|---|---|---|---|---|---|
| | 0% | 5% | 10% | 15% | 20% |
| KM Deep | 253 | 182 | 136 | 105 | 84 |

(1) Based on forecast prices and costs at January 1, 2014 (see Price Forecast in Section 3).
(2) The net present values may not necessarily represent the fair market value of the resources.

**Table 5 - Mirach Risked Mean Prospective Resources Net Present Value Summary**

## 2 RESERVES AND RESOURCES DEFINITIONS

The definitions employed in this evaluation conform to the 2007 Petroleum Resource Management System jointly published by the Society of Petroleum Engineers ("SPE"), World Petroleum Council ("WPC"), American Association of Petroleum Geology ("AAPG") and the Society of Petroleum Evaluation Engineers ("SPEE").

### 2.1 Resources

The term "resources" is intended to encompass all quantities of petroleum naturally occurring on or within the Earth's crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered "conventional" or "unconventional."

The resources classification framework is summarized in Figure 2 and a summary of the definitions is given below.

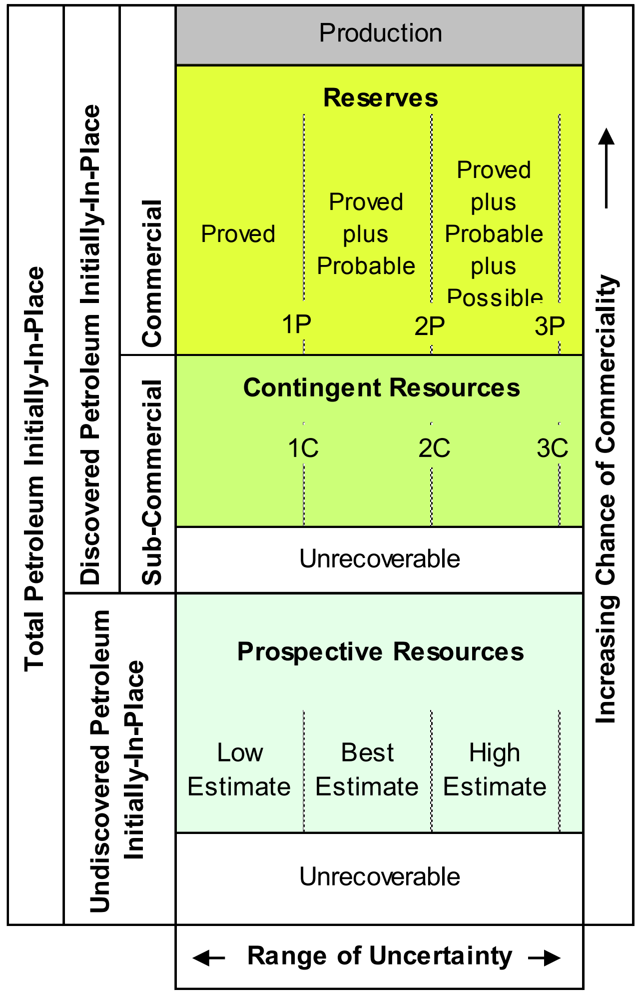



**Figure 2 – Resource Classification Framework**

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

The quantities estimated to be initially-in-place are defined as Total Petroleum-initially-in-place, Discovered Petroleum-initially-in-place and Undiscovered Petroleum-initially-in-place, and the recoverable portions are defined separately as Reserves, Contingent Resources, and Prospective Resources. Reserves constitute a subset of resources, being those quantities that are discovered (i.e. in known accumulations), recoverable, commercial and remaining.

**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 categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

The reserve classification system is covered in Section 2.3.

**Contingent Resources**

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

**Prospective Resources**

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity (see Section 2.6).

## 2.2 Range of Uncertainty

The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. When the range of uncertainty is represented by a probability distribution, a Low, Best, and High Estimate shall be provided such that:

- There should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the Low Estimate.
- There should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the Best Estimate.
- There should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the High Estimate.

When using the deterministic scenario method, typically there should also be Low, Best, and High Estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental (risk-based) approach, quantities at each level of uncertainty are estimated discretely and separately.

These same approaches to describing uncertainty may be applied to Reserves, Contingent Resources, and Prospective Resources. While there may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable quantities independently of such a risk or consideration of the resource class to which the quantities will be assigned.

## 2.3 Reserves Categories and Status

For Reserves, the general cumulative terms Low/Best/High Estimates are denoted as 1P/2P/3P, respectively. The associated incremental quantities are termed Proved, Probable and Possible. Reserves are a subset of, and must be viewed within context of, the complete resources classification system.

### Proved Reserves

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 percent probability that the quantities actually recovered will equal or exceed the estimate.

### Probable Reserves

Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50 percent probability that the actual quantities recovered will equal or exceed the 2P estimate.

### Possible Reserves

Possible Reserves are those additional Reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) Reserves, which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10 percent probability that the actual quantities recovered will equal or exceed the 3P estimate.

Reserves status categories define the development and producing status of wells and reservoirs.

**Developed Reserves**

Developed Reserves are expected quantities to be recovered from existing wells and facilities. Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.

**Developed Producing Reserves**

Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

**Developed Non-producing Reserves**

Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or, (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion prior to start of production.

**Undeveloped Reserves**

Undeveloped Reserves are expected quantities expected to be recovered through future investments: (1) from new wells on undrilled acreage, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

## 2.4 Contingent Resource Categories

For Contingent Resources, the general cumulative terms Low/Best/High Estimates are denoted as 1C/2C/3C respectively. No specific terms are defined for incremental quantities within Prospective Resources.

## 2.5 Prospective Resource Categories

For Prospective Resources, the general cumulative terms Low/Best/High Estimates apply. No specific terms are defined for incremental quantities within Prospective Resources.

## 2.6 Prospective Resource Sub Classes

Prospective resources can be sub classified in terms of project maturity into prospects, leads and plays.

**Prospect**

A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.

**Lead**

A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.

**Play**

A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.

## 3 PRICE FORECASTS

The net present value estimates were based on the McDaniel January 1, 2014 price forecast. A summary of the reference crude oil price forecasts and the export prices for the various properties is presented in Table 6. The sales gas price for Kampung Minyak is difficult to determine at this stage but is based on regional data.

| Year | Brent (1) Crude Oil Price $US/bbl | KM Oil Export Price (2) $US/bbl | Sales Gas Price $US/Mcf | Inflation Forecast % |
|---|---|---|---|---|
| 2014 | 105.00 | 104.35 | 5.00 | 2 |
| 2015 | 102.50 | 101.84 | 5.10 | 2 |
| 2016 | 100.20 | 99.52 | 5.20 | 2 |
| 2017 | 97.70 | 97.01 | 5.31 | 2 |
| 2018 | 98.00 | 97.30 | 5.41 | 2 |
| 2019 | 99.40 | 98.68 | 5.52 | 2 |
| 2020 | 101.30 | 100.57 | 5.63 | 2 |
| 2021 | 103.40 | 102.65 | 5.74 | 2 |
| 2022 | 105.40 | 104.64 | 5.86 | 2 |
| 2023 | 107.60 | 106.82 | 5.98 | 2 |
| 2024 | 109.70 | 108.91 | 6.09 | 2 |
| 2025 | 111.90 | 111.09 | 6.22 | 2 |
| 2026 | 114.20 | 113.38 | 6.34 | 2 |
| 2027 | 116.40 | 115.56 | 6.47 | 2 |
| 2028 | 118.80 | 117.94 | 6.60 | 2 |
| 2029 | 121.18 | 120.30 | 6.73 | 2 |
| 2030 | 123.60 | 122.71 | 6.86 | 2 |
| 2031 | 126.07 | 125.16 | 7.00 | 2 |
| 2032 | 128.59 | 127.66 | 7.14 | 2 |
| 2033 | 131.16 | 130.22 | 7.28 | 2 |

**Pricing Assumptions:**

(1) Brent price forecast based on the McDaniel & Associates January 1, 2014 price forecast

(2) KM Crude oil export price based on a US $0.65/bbl differential to Brent (increased with inflation) and accounts for transportations costs, quality differences and marketing fees.

**Table 6 – Price Forecast Summary**

## 4 KAMPUNG MINYAK KSO CONTRACT

### 4.1 Property Overview

The Kampung Minyak Production Enhancement KSO Contract (the "Kampung Minyak KSO Contract") covers an area of approximately 45 square kilometres within South Sumatra, Indonesia and includes the Kampung Minyak ("KM") oil field. A map of the South Sumatra Area where the block is located is shown in Figure 3.

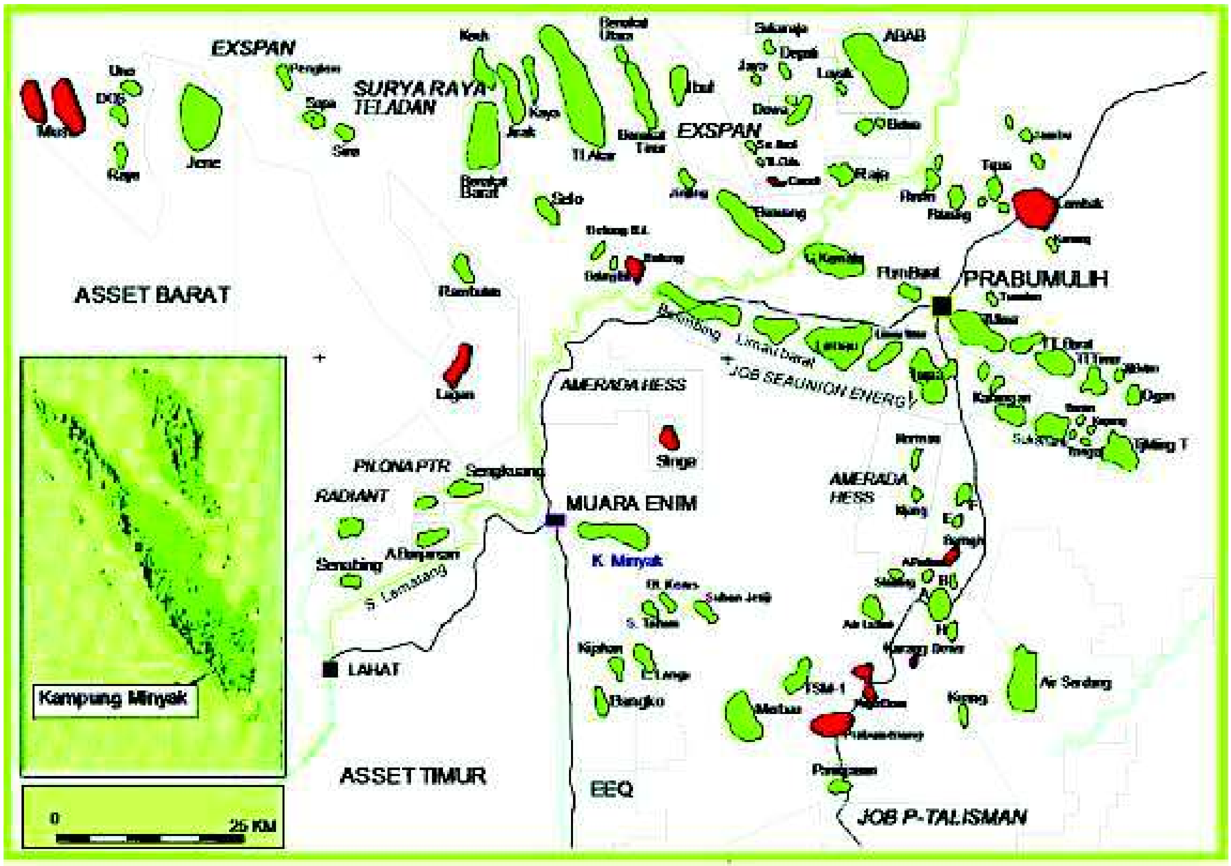



**Figure 3 – KM Field, South Sumatra Area Map**

The KM Field was discovered in 1896 by well KPM-1 drilled by the Muara Enim Petroleum Company, which later became part of Royal Dutch Shell ("Shell"). The field was produced until 1934 by Shell who drilled over 250 wells. Production records for this period are limited but indicate that approximately nine million barrels of oil were produced between 1896 and 1932. It is unclear what happened to the field during the Japanese occupation (1942 to 1945) and after Indonesia became independent in 1945. The next recorded activity at the field was in 1974 and 1975 when the Canadian company Bow Valley Energy drilled a number of appraisal wells; however, there was limited, if any, production. It is not clear when Bow Valley's involvement in the field ended. Between 1984 and 1988 Nordell International Resources ("Nordell") of the USA worked over a number of old wells and drilled approximately eight new wells. In addition, a rehabilitation and secondary contract for the Enim fields (including KM) was agreed between

Nordell and Pertamina (the Indonesian National Oil and Gas Company) which led to the startup of production in 1988. In September 1988 Triton Energy ("Triton") of the USA agreed with Nordell to take over operatorship of the field. Triton implemented a water injection project on the main STC zone and continued drilling both producers and water injection wells. Production peaked at 1,400 bopd in 1991. Water injection appears to have been stopped in 1997 at a time of low oil price and was never reintroduced. In 1996 Triton exited the field and operatorship was taken over in October 1996 by Pertamina (after briefly passing to an Indonesian company (Domestic Apex Oil and Gas Ltd)).

In total 311 wells have been drilled to date and cumulative production is estimated to be approximately 12 million barrels. In 2009 Pertamina began the process of finding another operator for the field which resulted in the signing of joint operations (KSO) contract in July 15, 2011 with Mirach.

Mirach believes there is the potential to increase production on the existing zones by installing better artificial lift, stimulating wells, recompleting wells, re-introducing water injection and carrying out infill drilling. The contingent resources associated with this activity are the focus of the evaluation. In addition, Mirach believes there may be additional potential in deeper zones below the existing productive zones, which in the case of one zone has been confirmed by recent drilling. Some records suggest that two of these deeper zones may have produced during short term tests but there is insufficient information available to verify this.

Production from groups of between 4 to 8 wells is gathered at small tanks where the gas is vented before the fluids are pumped to one of two production stations. The main production facilities consist of the two production stations, KM and KM500 where there is simple atmospheric separation and venting of the gas with an approximately 600 bbl capacity holding tank (one at each station) to allow gravity separation of the oil and water. Oil from the KM station is pumped to the KM500 station where further processing occurs to improve the BW&W quality of the export crude. In addition to the main 600 bbl tank the KM500 station has two 150 and 220 bbl tanks to allow further separation and storage of the oil prior to export. Currently an export pump is run intermittently to export crude to a Pertamina operated facility some 25 kilometres away. Demulsifier is also being added at the KM500 station to improve separation of the oil and water. Additional tanks will be required if production is to be increased to the levels envisaged in this evaluation.

Produced water is disposed of into the shallow S3 zone at two wells close to both production stations. The water injection facilities present during the early 1990s were removed and will need to be replaced before a water injection scheme to improve recovery can be implemented.

Mirach owns a 12.5 kilometre, 2.875-inch pipeline to the Batu Keras Field. Here the crude oil joins a Pertamina operated 6.9 kilometre, three-inch pipeline to the SPU66 production station where the KM Field production is metered. Ultimately further metering will need to be introduced once it becomes necessary to commingle the KM and Batu Keras production (both fields currently export intermittently). From SPU66 the crude oil joins the Pertamina local pipeline system and is transported just over 150 kilometres to the sales point. Mirach pays a pipeline tariff of US $0.65 per barrel for using this pipeline. Pertamina is responsible for sales and marketing of the crude. The current Mirach owned 2.875-inch pipeline to the Batu Keras Field should be able to handle the forecast production associated with contingent resources from the KM Field, but if prospective resources are discovered additional pipeline capacity may be required.

Travel through the field is on unmade, rutted roads which could become impassable after heavy rain. Improvements both to these in-field roads and to the access road from the town of Muara Enim some 10 kilometres away will need to be made if the scale of operations is to increase.

Since taking over the field in July 2011, Mirach has focused on optimizing production from the existing wells, carrying out basic maintenance of the existing facilities and drilling eight new wells. During 2013, the field production rate increased from 65 bopd (from 17 producing wells) at the start of the year to 135 bopd (from 22 producing wells) in December with a water cut of 80 percent.

### 4.2 Ownership and Contract Terms

The KM KSO Contract effective July 15, 2011 is between Pertamina and Prisma Kampung Minyak (the “Partner”) who is tasked with operating the field. Prisma Kampung Minyak was acquired by an affiliated company of Mirach in July 2011 and thus Mirach has a 100 percent working interest.

The contract terms are similar with other Indonesian KSO contracts. The contract period is for 15 years with a minimum work program over the first three years comprising of 25 square kilometres of 3-D seismic, the drilling of three new wells, the re-opening of 25 wells, the work-over of 30 wells and the building of a water injection facility. Pertamina needs to approve expenditure in advance (well services are excluded) to ensure the costs are associated with field operations and can be recovered. The contract stipulates a baseline production level above which the Partner is entitled to receive revenue on the incremental production. Eligible costs are recoverable up to 80 percent of gross incremental revenue. Profits from the incremental production are split between the Government, Pertamina and the Partner. There is a domestic market obligation (“DMO”) of up to 25 percent of the partner’s profit oil production at a price equivalent to 25 percent of the normal selling price. Corporate tax will also be payable at 40.5 percent on any Partner profits. To date Mirach has drilled the three new wells stipulated under the minimum work program. The Mirach work plan for 2014 includes the installation of new water injection facilities and the acquisition of the 3-D seismic.

Mirach has an agreement with Pertamina to use the local pipeline infrastructure for a cost of US $0.65 barrel.

Mirach has a risk service contract with Daqing Enterprise International (“DQE”) to manage and carry out the field operations. DQE is a subsidiary of the Petro China Daqing Oilfield Company Limited and has extensive experience of field operations within the mature Daqing oil field in China. These skills and experience will be valuable for carrying out the planned redevelopment activities at the KM Field.

### 4.3 Source and Quality of Data

In general terms the dataset was poor. It is not totally clear how many wells may have been drilled in the past, but well coordinates exist for 319 wells and 113 wells have log data available. Of these 58 wells have sufficient log data to enable basic petrophysical interpretation, while 40 wells only have an induction log and a porosity log. The better log data is concentrated in the areas of greatest development and is somewhat limited in the other areas. Core data (porosity-permeability) was provided for 13 wells and a core description was provided for one well.

The historical production data was also very limited. Monthly production data was provided for individual well/zones for the period 1989 to 1995 and 2001 to December 2013. A status summary of the wells was also provided as of November 2004 which listed the cumulative oil, water and gas for each well/zone for most wells; this data could not be verified and also means that only 20 percent of the production to date is in a monthly format.

Seismic coverage over the field consists of 13, 2-D lines, which provide a coarse grid over the main structure. The seismic data was acquired in 2004 as part of a regional survey over KM and some neighbouring structures. A seismic interpretation for the Air Benekat and deeper formations was provided by Mirach and found to be reasonable. Top structure maps provided for the main prospective reservoirs were considered reasonable and used as the basis for the prospective resources assigned in this CPR. A map showing the location of the seismic lines together with the known well locations is presented in Figure 4.

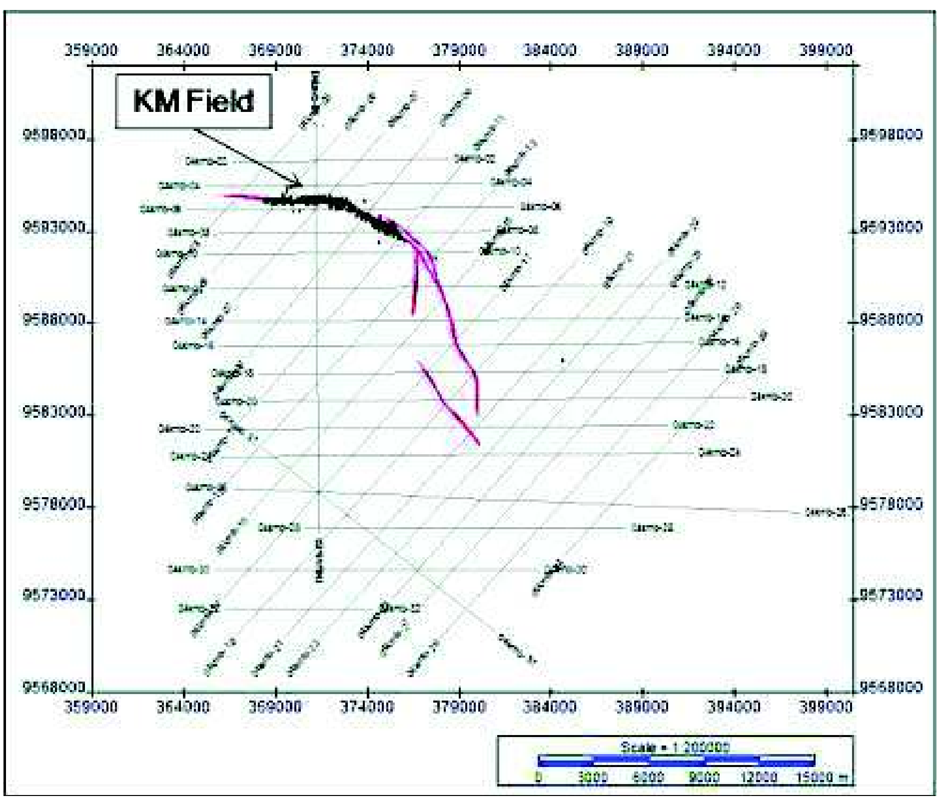



**Figure 4 – KM Regional Seismic and Well Location Map**

### 4.4 Regional Geology – South Sumatra Basin

The KM Field is located in the South Palembang depression of the South Sumatra Basin in Indonesia. The South Palembang is the larger of the two rift provinces within South Sumatra.

The sediments that make up the reservoir zones in the KM Field were deposited during the late post-rift stage. During this time a phase of deltaic progradation distributed the sediments across the basin.

Three main tectonic phases are recognized in the late post-rift stage:

- Paleocene to Early Miocene extension and Graben Formation.
- Early Miocene to Early Pliocene quiescence.
- Pliocene to Recent, transpression and inversion forming extensive sub-parallel west-northwest to east-southeast anticlinal trends.

### 4.5 Geology of the Kampung Minyak Block

A brief description of the structure and stratigraphy is given in the following subsections.

#### 4.5.1 Structure

The Kampung Minyak Field comprises a narrow anticline striking in a southeast to northwest (and west) direction. The field has a total length (east-west) of approximately eight kilometres and a maximum width of approximately one kilometre. A top structure map for the Upper STC zone is presented in Figure 5.

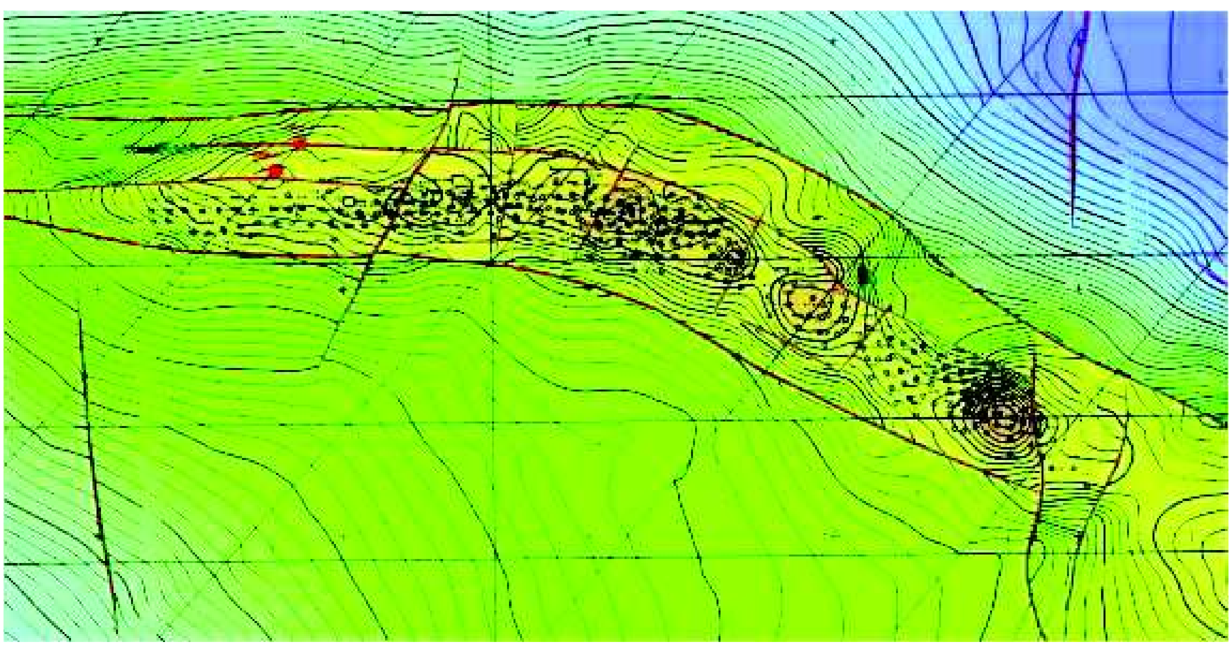


**Figure 5 – KM Field USTC Zone Top Structure Map (Source Mirach)**

The structure is divided along its length into 10 separate blocks by reverse faults striking perpendicular to the trend of the anticline. Seismic sections show very obvious relief and block segregation along the field with the main trapping component being anticlinal dip closure.

A seismic dip section showing the interpreted structural configuration is presented in Figure 6.

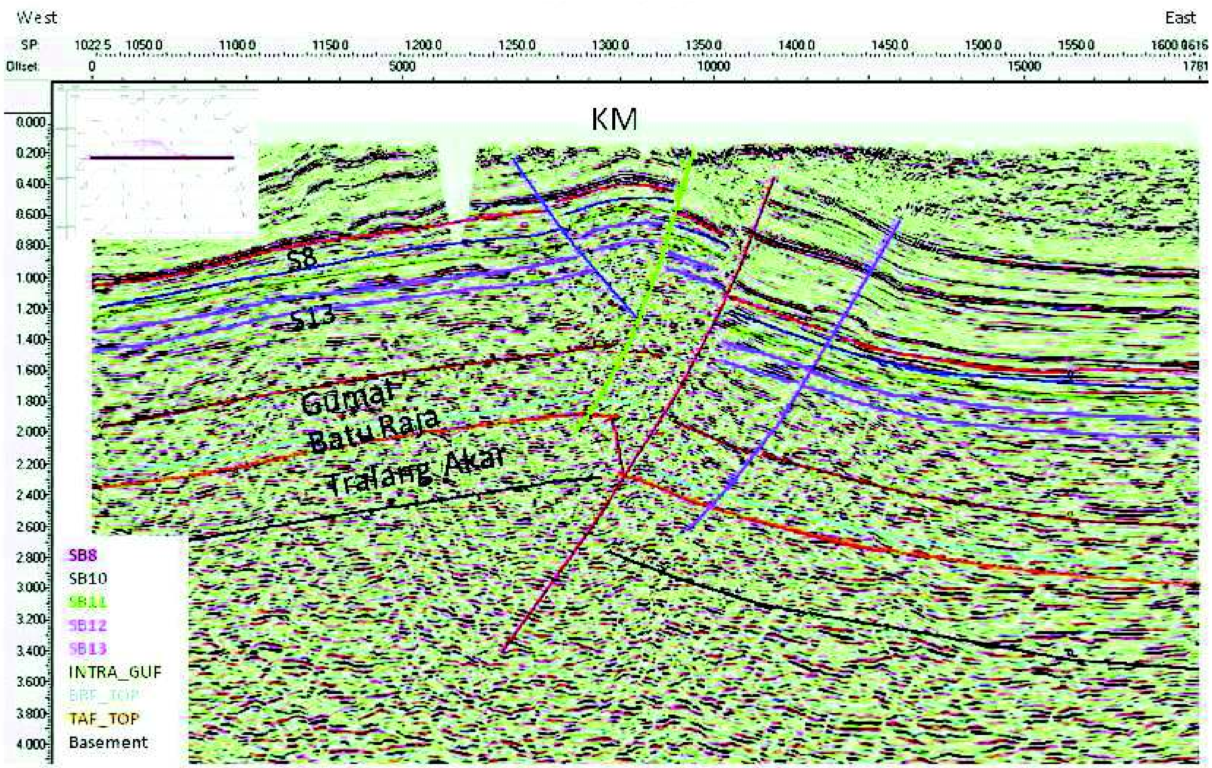



**Figure 6 – KM Field Seismic Dip Line 04kmb-06**

### 4.5.2 Stratigraphy

There are two main formations present in the field. The Muara Enim Formation and the Air Benakat Formation. A stratigraphic chart is presented in Figure 7.

**STRATIGRAFI KAMPUNG MINYAK**

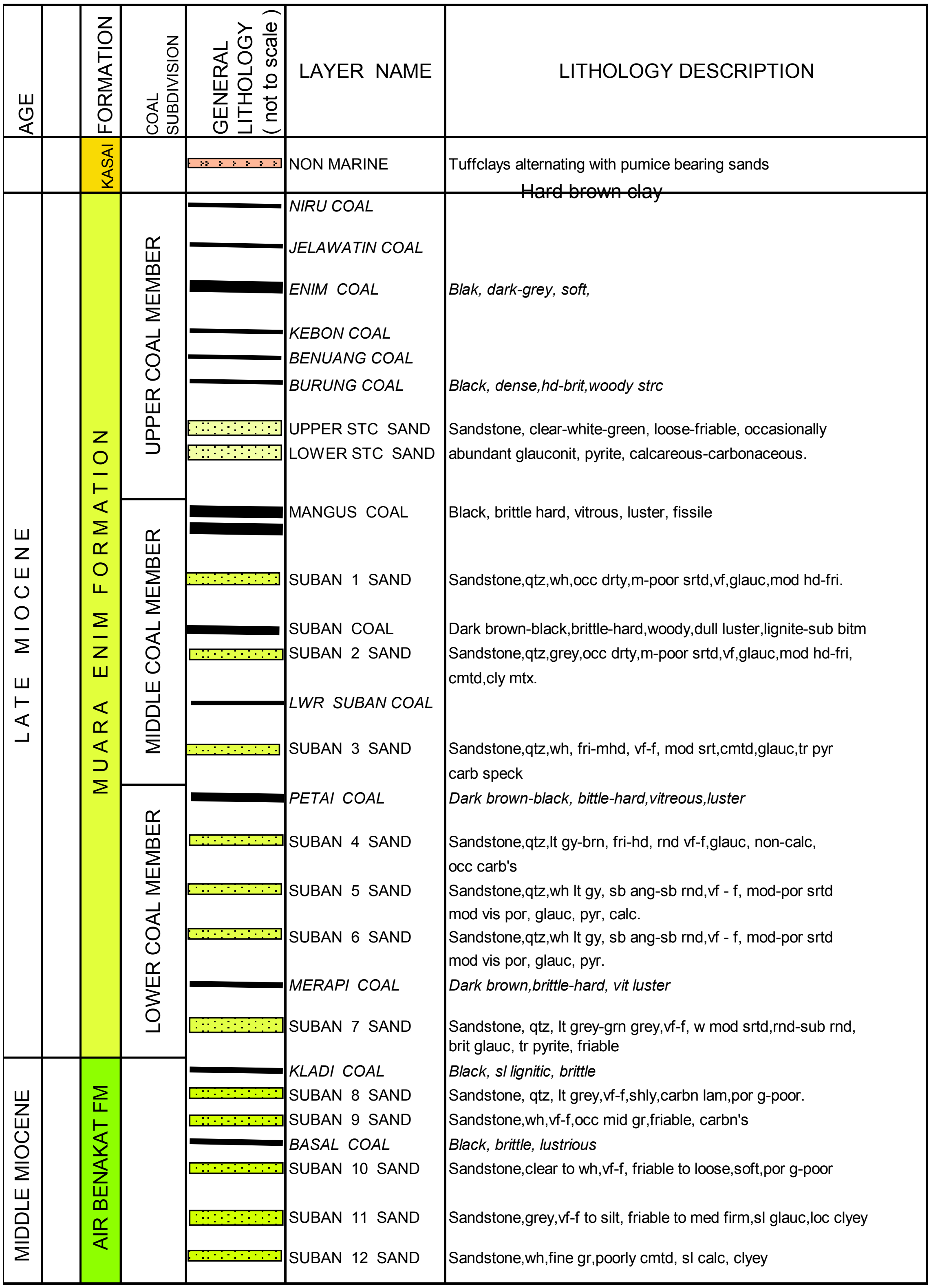



**Figure 7 – KM Field Stratigraphic Chart (Source Mirach)**

### 4.5.3 Muara Enim Formation

The Muara Enim Formation sediments are of the late Miocene to early Pliocene age. From their profile on the wireline logs they appear to be deposits of a low relief coastal area. This generalized depositional environment is interpreted from the numerous laterally extensive coals interbedded with fine grained sands and shales.

A large proportion of the production from the field comes from the shallow STC zone, which is separated into a lower and an upper sand. These are the best developed sands within the section in terms of thickness, consistent reservoir quality, and lateral sand continuity. The sands are distributed across the entire length of the anticline.

The section of sands below the STC are designated the Suban 1 (S1) to Suban 7 (S7) from top to bottom. The S3 is further subdivided into the S3a, S3b and S3c and the S7 is subdivided into the S7a, S7b and S7c, which makes with USTC and LSTC a total of 13 reservoir zones. With some exceptions, the S1 to S7 sands do not appear to be as well developed as the STC sands. They appear argillaceous on the wireline logs with low spontaneous potential ("SP") responses and little movement on the resistivity curves. Often the density curves show anomalously high porosity probably caused by loss of pad contact with the washed borehole.

A Nordell core description from well KPM-1 across the S7 zone (divided into the S7b and S7c) gives further evidence that the sands are interlaminated and very fine to fine grained. The S7b is described as a thinly interlaminated claystone and sandstone with laminations that are 0.5 to several millimetres thick. The sand laminations are described as very fine to fine grained and argillaceous in part. This would be very typical of a tidal flat deposit in the intertidal zone. Below the S7b, the S7c shows an increase in sand content and is described as sandstone with minor laminations of claystone.

The conclusion from the analysis of the logs for approximately 25 wells is that the majority of the S1 to S7 interval is of relatively poor reservoir quality. Occasionally there are pulses of better quality sand which are most frequently seen in the S7c, S7b, S6 and S3a zones. These zones tend to show a little more lateral sand continuity than the other zones and have the log characteristics of a slightly higher energy deposit with fair to good log responses on the Gamma Ray, SP, calliper, and Neutron-Density logs. These deposits could be the result of slightly higher energy deposits in the tidal environment, including tidal distributary channels, crevasse splays, or tidal ridges. The absence of a coarser clastic interval at the base of any of the S1 to S7 deposits suggests that a large fluvial system was not in the vicinity at the time of deposition. On the basis of this work it was decided to exclude the S2, S3c and S4 zones from the evaluation as we were unable to identify any net pay.

### 4.5.4 Air Benakat Formation

The Air Benakat Formation is similar to the Muara Enim in that it is a large interval made up of interbedded shales and sands subdivided into separate zones by coal deposits. The zone names continue from the last sand of the Muara Enim and are named from top to bottom S8 to S13 respectively.

The deposits of the Air Benakat represent the beginning of a major phase of regression and comprises finer grained, delta front to delta plain deposits, whereas the Muara Enim is more characterized by delta plain to continental plain deposits.

In the KM Field only four wells with log data penetrate this sequence and, of these, only one well, KM 55/23-96, goes deep enough to cover all the zones to S13. Only one of the wells appears to have been production tested (KM 55/22-55J) and no longer term production data exists for the zones in these wells. Some oil production (13,000 bbl) is reported from the S8 zone from two other wells, KM-52 and KM-370, but no well data is available for these wells to establish if this is reliable. Four of the new wells drilled during 2012 and 2013 drilled to the base of the S8 zone but only KM-607 is interpreted to have net pay within the S8 which was subsequently confirmed by testing initially at rates over 200 bopd with no water. The oil rate has though declined rapidly and in December 2013 the well was producing at 18 bopd with a 60 percent water cut.

Overall the sands appear to be quite shaly resulting in subtle log responses on the SP and resistivity curves. One notable exception is the S10 well, which is developed in well KM 55/22-55J and appears as a package of three stacked sands totalling 20 metres of net sand with a positive SP response and a good density porosity reading, ranging from 18 to 25 percent. This zone was tested in 1985 and after acidizing and swabbing produced 103 bopd with a 50 percent water cut. It is unclear if this rate was sustainable and as the zone was not subsequently produced it was decided not to assign contingent resources at this stage.

Contingent resources were assigned to the S8 formation around well KM-607. Prospective resources were assigned to the S8 beyond well KM-607 and to the S9 to S13 sands.

### 4.5.5 Gumai Formation

The Gumai Formation lies immediately below the Air Benakat Formation and is regionally a thick marine shale deposited in the early Miocene. In the South Sumatra Basin it is regarded as a potential regional seal for the deeper Talang Afar and Batu Raja formations. In some shelfal areas around the basin margins the shale is intercalated with thin limestones and calcareous sandstones with good reservoir quality and some associated hydrocarbon accumulations, especially in the Jambi depression (north of the South Palembang depression). In some other areas, especially to the west towards the Talang Babat Deep, the sand to shale ratio increases as result of turbidite incursions and again has reservoir potential.

Although there is a possibility of hydrocarbon potential in the KM Area, too little data was made available for this evaluation to be able to quantify it and so no prospective resources have been assigned. It is worth noting that the nearest field producing from the Gumai Formation is some 50 kilometres away.

#### 4.5.6 Batu Raja Formation

In the early Miocene a sudden reduction in the supply of clastic sediments into the basin resulted in the development of large carbonate platforms around the basin margins and on basement highs. Later, these platforms became the foundations for reefal and detrital bank buildups with considerable relief. This whole carbonate unit is the Batu Raja Formation. The average thickness is 60 to 75 metres but can be up to 200 metres. Off structure, the zone can grade into the shaly facies of the Gumai Formation.

In the topographical highs the porosity in the carbonate buildups was enhanced by sub-aerial leaching, and hence the best reservoir potential is usually in the upper part of the reservoir. This zone is an important secondary target as is considered to have the greatest remaining potential in the South Sumatra Basin.

Although there is a possibility of hydrocarbon potential in the KM Area, too little data was made available for this evaluation to be able to quantify it and so no prospective resources have been assigned. In the Limau area, which is some 30 kilometres away, there is production from the Batu Raja Formation, however, it is not clear if this is a direct analogue for the KM Area.

#### 4.5.7 Talang Akar Formation

The Talang Akar Formation is the most significant play and petroleum system in the South Sumatra Basin. It is a thick sequence of interbedded sands, shales, and coals deposited in the Late Oligocene. The lower part of the zone, often referred to as the Gritsand Member, is composed of coarse grained fluvial sandstones alternating with shale and coal deposited in a deltaic environment with gross thickness ranging between 200 and 500 metres. The upper portion, known as the Transitional Member, becomes more marine influenced with finer grained sandstones alternating with shales and coals. The gross thickness of this section is on the order of 300 metres.

Most of the Talang Akar plays are associated with anticlinal folds or reverse faults resulting in rollover anticlines. In addition some plays exist as stratigraphic pinchouts of sand lenses against basement highs. At the KM Field the seismic interpretation indicates the Talang Akar is below the pop-up anticlinal structure that forms the trap for Muara Enim Formation and potentially the Air Benakat Formation. In the case of the Talang Akar the trap is interpreted to be formed by sands abutting against a major fault as interpreted in the seismic section presented in Figure 6.

Another issue at KM is the likely depth of the formation which is interpreted to be at 2,300 metres and as such may contain gas.

The close proximity of several fields producing from this formation suggests it has potential at the KM Field and hence prospective resources have been assigned.

### 4.6 Contingent Resources

The KM Field has many wells and is considered relatively mature. The total production to date is estimated to be approximately 12 million barrels for the zones evaluated which represents approximately 18.5 percent of the estimated OOIP. With a field at this stage of development, the analysis of the production history is very important and can typically be used to estimate both the developed and undeveloped future potential. However, the absence of the complete monthly production data on a well by well basis throughout the field history limits the usefulness of the production analysis in this case. Instead more weight had to be given to a volumetric approach for estimating future performance. Unfortunately the very high recovery to date on some pools (a pool being a separate block within a zone) calls into question the production allocation to date and also limits the usefulness of this approach. The future development potential will therefore need to be established by piloting further infill drilling in different areas of the field, gathering production data across all the zones and by piloting the re-introduction of water injection. At this stage it is too early to extrapolate the results of the initial activities and confirm whether the the development plans proposed by Mirach will be economic.

Developed reserves have not been assigned as part of this evaluation, as the forecast production revenue from the existing wells is unlikely to cover the operating costs.

For the above reasons, all the discovered remaining recoverable resources are classified within this evaluation as contingent resources rather than reserves. As more results become available and commerciality is confirmed it should be possible to reclassify some, or all, of these contingent resources as reserves

#### 4.6.1 Volumetrics

A volumetric estimation of the OOIP for KM Field was undertaken using a set of net oil pay maps provided by Pertamina to Mirach. McDaniel audited these maps based on the petrophysical interpretation of the wireline logs from a selection of wells distributed across the field together with the production and well test information. There is no evidence from the production data that zones interpreted as being non pay on the logs were actually capable of sustaining oil production. In certain zones the net pay maps in our opinion overstate the net pay McDaniel would interpret from the logs. To compensate for this the net rock volume derived from the Pertamina maps for each zone was adjusted by a percentage as presented in Table 7. This percentage represents the difference in net pay from our interpretation compared to the mapped net pay. Specific blocks for some zones were omitted if there was no evidence of pay on the logs and no historical production had been assigned to the block.

| Reservoir Zone | [McDaniel Net Pay] / [Mapped Net Pay] % |
|---|---|
| USTC | 100 |
| LSTC | 100 |
| S1 | 60 |
| S3a | 60 |
| S3b | 70 |
| S5 | 75 |
| S6 | 75 |
| S7a | 50 |
| S7b | 65 |
| S7c | 90 |

**Table 7 – KM Field Net Pay Adjustment**

The USTC and LSTC net pay maps were combined to generate an overall STC net pay map and is presented in Figure 1 of the Appendix. A combined net pay map was also prepared for the S1 through to S8 zones and is presented in Figure 2 of the Appendix. Both net pay maps show using red well symbols the wells which have produced to date.

A table of average porosity values for each zone in a number of wells (assumed to be from core plugs) was provided and considered to be reasonable. The average porosity from the STC sands is 32 percent with the majority of the samples having a permeability ranging from 50 to 300 mD. The porosity in the S1 to S7 sands generally decreases with depth and the average porosity ranges from 31 percent in the S1 to 27 percent at the S7 level. Permeability varies again with each sample point and within each layer, from a few millidarcy to a few hundred millidarcy.

Water saturations were provided by the client and considered reasonable. Calculating water saturation using conventional petrophysical evaluation methods would result in incorrect high water saturations because of the low response on the resistivity curves often seen across very fine clastic grain sizes and uncertain water salinity. The water saturations used for the OOIP calculations range from 35 percent in the STC units to a high of 44 percent in the S5. The evidence that oil does exist in these zones has been confirmed by some production and by good indications of oil shows in the core description.

The KM oil is of good quality ranging in API gravity from 35 to 45 degrees and has a gas oil ratio ("GOR") from 100 to 500 scf/stb. No PVT data was available for the field and a formation volume factor of 1.15 was used for all zones based on a reserves estimate made by Pertamina in 2005.

The adjusted net rock volumes determined from the net pay maps were combined with the other reservoir parameters to determine the OOIP on a zone/block basis and is summarized in Table 8.

| Zone / Block | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| USTC | 4,676 | 2,865 | 2,600 | 1,440 | 2,605 | 2,037 | 2,037 | 1,020 | - | 19,279 |
| LSTC | 7,054 | 2,436 | 1,782 | 1,699 | 1,727 | 6,221 | 251 | - | 2,029 | 23,199 |
| S1 | 126 | 593 | 485 | 169 | 73 | 451 | 700 | 111 | 266 | 2,974 |
| S3a | 241 | 924 | 1,124 | 220 | 232 | - | 1,158 | 378 | - | 4,276 |
| S3b | 259 | - | - | - | - | 649 | 1,980 | 374 | - | 3,262 |
| S5 | 122 | 464 | - | - | - | - | - | - | - | 585 |
| S6 | - | 226 | 256 | 162 | 235 | 260 | 902 | - | - | 2,040 |
| S7a | - | - | - | - | - | 83 | 708 | - | - | 791 |
| S7b | - | 1,114 | 895 | 305 | 299 | 328 | 1,705 | - | - | 4,646 |
| S7c | - | 701 | 728 | 110 | 199 | 97 | 1,893 | - | - | 3,727 |
| S8 | - | - | - | - | 161 | - | - | - | - | 161 |
| Total | 12,478 | 9,323 | 7,870 | 4,104 | 5,530 | 10,125 | 11,334 | 1,882 | 2,295 | 64,940 |

**Table 8 – KM Field Original Oil In Place Summary (Mbbl)**

### 4.6.2 Production Performance

The recent production history for the field, split by reservoir zone, is presented in Figure 8. As can be seen from the legend on Figure 8 production has not been allocated to all the individual subzones. The water cut has been above 60 percent over this whole period rising at times to 90 percent. Total fluid rates though have also declined in line with the oil rates suggesting some zones have declined in pressure and are not receiving aquifer support.

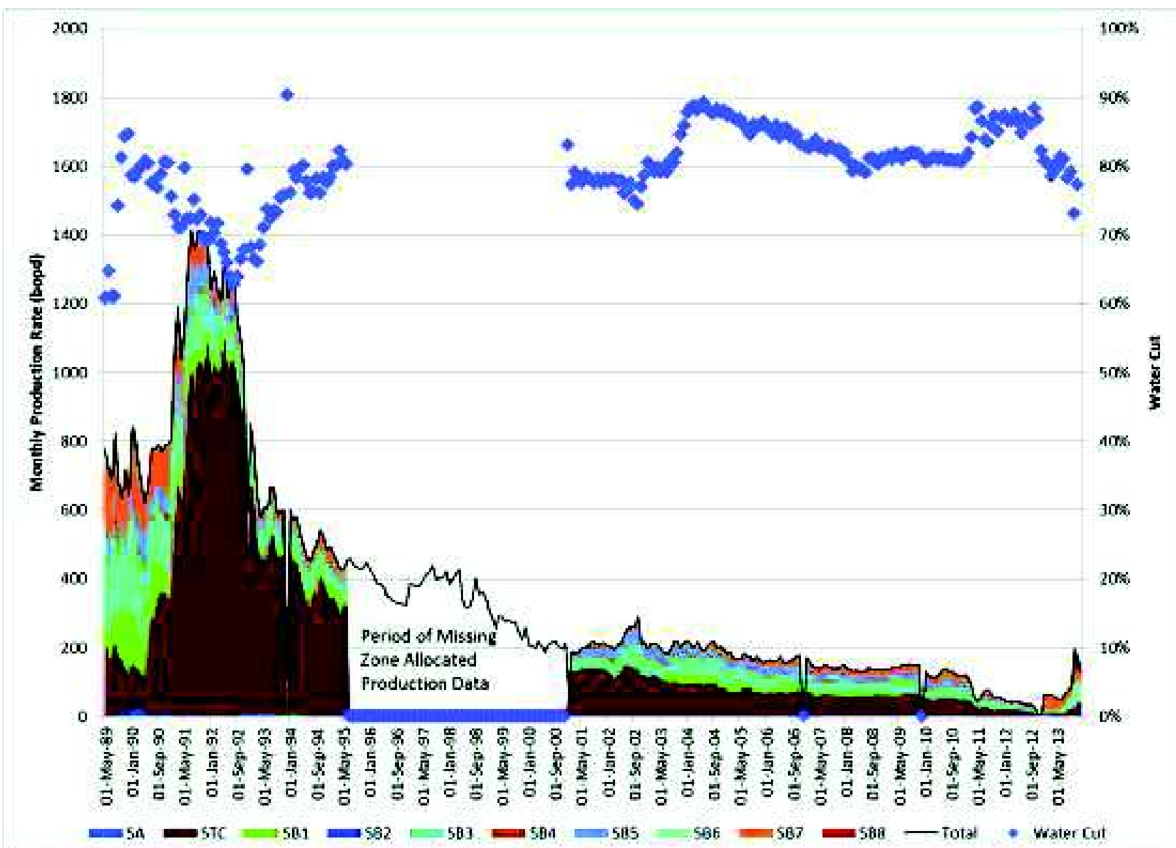



**Figure 8 – KM Field Recent Production History**

The production history since 1990 illustrates that historically the development has focused on the STC zone coinciding with the implementation of water injection. A number of water injectors were located in peripheral locations in the Block 3, 4 and 5 areas of the field and, together with some new wells, boosted production significantly. During this period water injection slightly exceeded reservoir voidage on these blocks. The lower field rate experienced after 2001 is most likely caused by the stopping of water injection in 1997. Based on these results further water injection should be implemented on the STC blocks which have good sand development.

The large numbers of wells means that the average well spacing for each pool is already relatively low. The deeper zones have progressively fewer wells, although even the deepest zone (the S7) has an existing spacing of between 12 and 33 acres (depending on the pool). The STC zone in the most developed areas has a well spacing of less than 10 acres per well (wells are less than 200 metres apart). This type of close well spacing is not normally associated with light oil reservoirs unless there is significant compartmentalization through faulting or lithological changes.

Production allocation to the individual zones should be considered approximate due to commingling that has sometimes occurred. Furthermore, the recently drilled wells have all commingled production across the S1 to S7 zones in order to maximize rates. Attempting to allocate production back to the individual zones no longer makes sense and for the purposes of this evaluation the USTC and LSTC were treated as a combined STC zone and the S1 through to S8 were combined as a S1-8 zone. In addition, a small amount of production has been assigned to the SA zone, which is above the STC zone, but is not thought by Mirach to have much remaining potential and was therefore excluded from this evaluation.

The production performance during the second half of 2013 has improved and the field is now producing more than the baseline production forecast. During 2013 Mirach carried out activities on 12 shut-in wells, mainly to replace failed pumps, resulting in an average gain of 2.9 bopd per well. The production performance of the new wells is presented in Figure 9. Wells KM-602 and KM-604 are not included as they are awaiting completion. Well KM-607 is atypical as it briefly obtained high rates from the S8 zone before declining rapidly. The new wells are all located in the central part of the field as presented in Figure 3 of the Appendix.

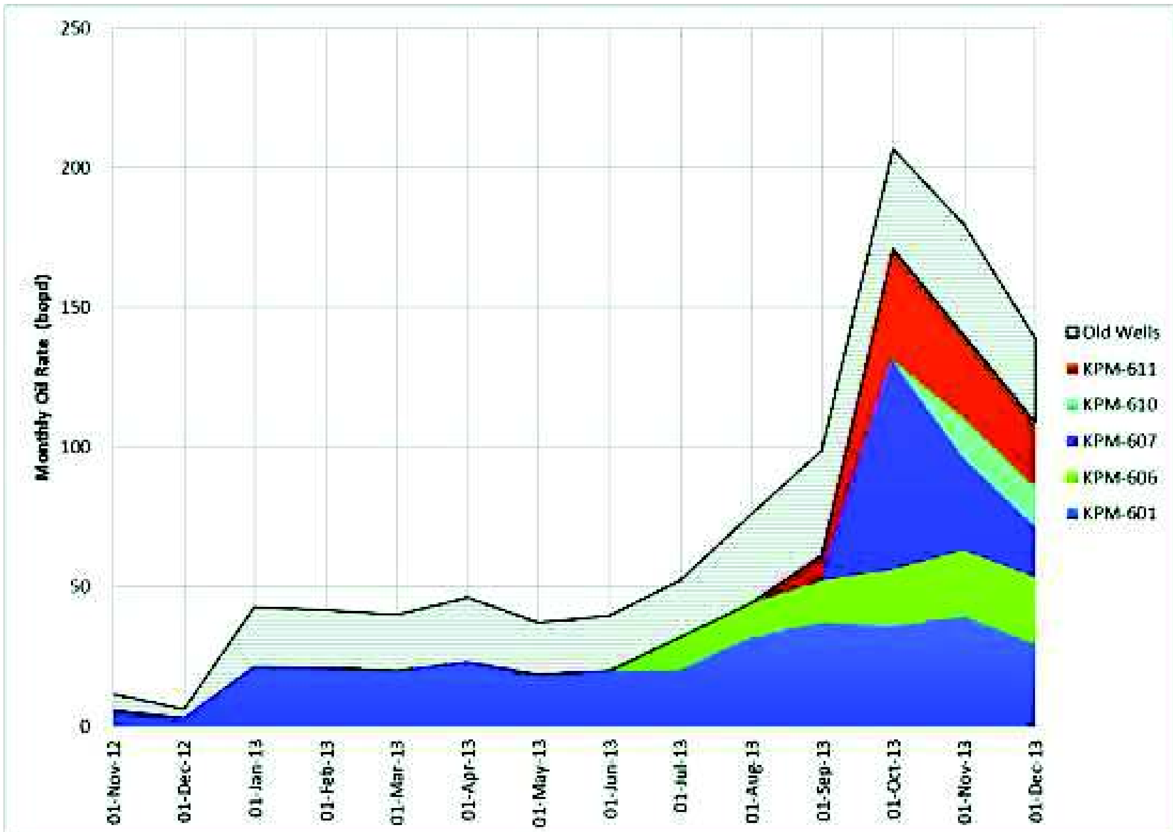



**Figure 9 – Recent New Well Performance**

### 4.6.3 Resource Estimates

The contingent resources were estimated assuming the re-introduction of water injection on the STC, the drilling of a number of infill wells and the reactivation of a percentage of the old wells.

For the STC the resources take into account the OOIP, the recovery to date, the existing well spacing and the room for drilling infill wells and the likely benefits of re-introducing water injection. It is still unclear whether these estimates are reasonable as only one of the recent wells has been completed on the STC zone (commingled with the S1, S3 and S4) and the assignment of contingent resources rather than reserves is considered more appropriate.

A similar volumetric approach was not considered valid for the S1-8 zones other than to guide where there may be more infill potential based on the recovery to date and the existing well spacing; well recoveries were instead based on an estimated initial rate for each well and an assumed decline rate. The initial rate assigned to the new wells was estimated based on the results of the recently drilled wells taking account of the likely difference in net pay in the location where the infill well would be located. This approach can only be considered reasonable if the existing wells, used to calibrate the well rates, are representative of the future wells to be drilled; unfortunately, this is unclear, as the number of recently drilled wells is relatively small and their production history is short (they are also limited to a small area of the field). Further drilling and production is required before this method can be refined and considered robust enough to assign reserves and hence contingent resources have been assigned.

A summary of the contingent resources assigned on a pool by pool basis is included in Table 1 for the STC zone, in Table 2 for the S1-8 zones of the Appendix. An overall summary of the contingent resources is presented in Table 3 of the Appendix. The tables also provide details of the future well requirements for each of the contingent resources categories.

An overall summary of Mirach's share of the crude oil contingent resources is presented in Table 9.

| Crude Oil Contingent Resources | 1C Low Est. | 2C Best Est. | 3C High Est. |
|---|---|---|---|
| Property Gross (1), Mbbl | 601 | 2,623 | 5,813 |
| Company Gross Share (2), Mbbl | 441 | 2,453 | 5,643 |
| Company Net Share (3), Mbbl | 356 | 1,134 | 2,209 |

(1) Property gross resources include the baseline production
(2) Company gross resources are based on the Mirach working interest share of the property gross resources less the baseline production.
(3) Company Net resources are based on the Mirach share of Cost Oil and Profit Oil revenues.

**Table 9 – KM Field Contingent Resources Summary**

### 4.7 Net Present Values of the Contingent Resources

The net present values for the contingent resources were based on future production and revenue analyses. The net present value estimates are presented in US Dollars and include an allowance for Indonesian taxes. The future production forecasts make an allowance for the reopening of some old wells, future production optimization, re-introduction of water injection on the STC zone and the drilling of new infill wells on the S1-8 zones. The production forecasts are presented in Figure 4 of the Appendix. Future crude oil revenue was derived by employing the forecast production and the forecast Brent crude oil price less an estimate of the price differential between the Brent reference price and the field price. The total differential according to Mirach is US $0.65 per barrel including all transportation costs, quality differences and marketing fees. As so far the KM Field production has been under the baseline production forecast, there are no sales statements to confirm the realized sales price.

Operating and capital costs are based on McDaniel estimates in consultation with Mirach. New wells are each predicted to cost US $ 400,000, which includes the cost of drilling, completion and hook up, and recompletions cost US $ 75,000. The cost to upgrade the production facilities and to build water injection facilities is predicted to be US $ 5.2 million for the 2C resource case rising to US $ 8.7 million for the 3C case. Mirach is only responsible for abandoning any future unsuccessful exploration wells; other wells will be handed back to Pertamina at the end of the KM KSO. Consequently, no allowance for abandonment has been included in this evaluation. The unrecovered cost oil balance at December 31, 2013 of US $4,537,000 was included in the economic model.

Mirach's share of the net present value estimates are presented in Table 10 below.

| | Net Present Values at December 31, 2013 (US$ M) (1) (2) Discounted At | | | | |
|---|---|---|---|---|---|
| | 0% | 5% | 10% | 15% | 20% |
| **Kampung Minyak** | | | | | |
| Low Estimate Case | 3,852 | 1,962 | 675 | (222) | (860) |
| Best Estimate Case | 24,707 | 16,451 | 11,089 | 7,489 | 5,003 |
| High Estimate Case | 59,711 | 40,718 | 28,676 | 20,701 | 15,227 |

(1) Based on forecast prices and costs at January 1, 2014 (see Section 3).
(2) The net present values may not necessarily represent the fair market value of the resources.

**Table 10 – KM Contingent Resources Net Present Value Summary (Mirach Share)**

The fiscal terms are defined within the Kampung Minyak KSO Contract with profits split between the Government, Pertamina and Mirach. There is a DMO of up to 25 percent of the partner's profit oil production at a price equivalent to 25 percent of the normal selling price. Corporate tax is also payable at 40.5 percent on any Partner profits. The price forecasts used are presented in Section 3.

### 4.8 Prospective Resources

Prospective Resources have been assigned to a number of zones within the Air Benekat and Talang Akar formations which underlay the discovered resources in the Muara Enim Formation.

Prospective resources for each prospect zone are based on probabilistic volumetric calculations. Low (P90) and High (P10) estimates were used to define the distributions which are assumed to be log normal. The parameters used were pool area, average net pay, porosity, oil or gas saturation together with estimated PVT parameters and recovery factors. The pool area was based on the prospect outlines estimated from the structure maps interpreted from the seismic data. For all prospects a geometric correction factor (frequently referred to as a shape factor) was used to account for the reduction in net pay at the edges of the field.

For the Air Benekat Formation the reservoir parameters were derived from the available logs and compared against those parameters from nearby fields such as the Suban Jeriji and the Suban Taham oil fields. The main risk attached to these zones is the presence of reservoir quality rock. The S10 was assigned the highest chance of success, whereas the S9 sand, appearing to be of poor quality in all four wells, (possibly non-existent) and laterally discontinuous, was given the lowest chance of success. Pool areas were derived from the top structure maps for each of the prospective zones of the Air Benekat Formation. The area around the wells where sands could be identified on the logs was used to define the Low case (P90) pool area (for the S8 this also included wells KM-52 and KM-370, which have been allocated a small amount of production). The high case (P10) pool area is based on the lowest closing contour (limited if necessary to the block boundary). The top structure maps for two of the main zones, the S8 and the S10 are presented in Figures 5 and 6 of the Appendix.

For the Talang Akar Formation the reservoir parameters are based on parameters from the Benakat Barat and Limau fields which are the nearest analogues at distances of 50 and 30 kilometres respectively. The greater depth of the formation, which is expected to be below 2,300 metres, suggests there may be gas present and a 50:50 split between oil and gas has been assigned. The top structure map for the Talang Akar Formation is presented in Figure 15 of the Appendix. The main risks relate to reservoir presence and structural configuration. As discussed previously the trap at KM is interpreted to be formed by sands abutting against a major fault, which is unlike most of the established traps that are associated with anticlinal structures. Although there are two separate mapped closures shown on Figure 15 (Appendix), the approach was simplified by treating these as one prospect.

The chance of discovery for any one zone has been assumed to be independent of the chance of discovery for the others and as such the overall chance of discovery is very high at over 99 percent.

A summary of some of the key input parameters for all the zones is presented in Table 11.

| | | Air Benekat | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Parameter** | **Estimate** | **S8** | **S9** | **S10** | **S11** | **S12** | **S13** | **Talang Akar** |
| Pool Area, acres | P90 | 207.0 | 160.0 | 400.0 | 315.0 | 190.0 | 245.0 | 160.0 |
| Pool Area, acres | P10 | 2,070.0 | 2,916.0 | 2,768.0 | 2,405.0 | 2,324.0 | 2,051.0 | 1,532.0 |
| Gross Pay, ft | P90 | 110.0 | 200.0 | 285.0 | 140.0 | 500.0 | 325.0 | 800.0 |
| Gross Pay, ft | P10 | 150.0 | 230.0 | 330.0 | 180.0 | 700.0 | 425.0 | 1,400.0 |
| NTG Ratio, % | P90 | 12.0 | 6.0 | 7.0 | 8.0 | 5.0 | 6.0 | 10.0 |
| NTG Ratio, % | P10 | 20.0 | 11.0 | 14.0 | 15.0 | 12.0 | 12.0 | 17.0 |
| Porosity, % | P90 | 19.0 | 19.0 | 19.0 | 19.0 | 19.0 | 19.0 | 17.0 |
| Porosity, % | P10 | 26.0 | 26.0 | 26.0 | 26.0 | 25.0 | 25.0 | 23.0 |

**Table 11 – KM Field Prospective Resources Main Input Parameters**

The prospect was risked using the parameters summarized in Table 12.

| | Air Benekat | | | | | | |
|---|---|---|---|---|---|---|---|
| **Parameter** | **S8** | **S9** | **S10** | **S11** | **S12** | **S13** | **Talang Akar** |
| Source | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Migration & Time | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Reservoir | 0.60 | 0.40 | 0.80 | 0.50 | 0.60 | 0.50 | 0.50 |
| Structure | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 0.40 |
| Seal | 0.90 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 1.00 |

**Table 12 – KM Field Prospective Resources Geological Chance of Discovery**

A summary of the prospective resources for each zone is presented in Table 4 of the Appendix on a property gross basis. The prospective resources at a prospect level are summarized in Table 4 in Section 1.3 and repeated below for ease of reference.

**Prospective Resources: Crude Oil and Condensate (MMbbl)**

| Prospect (1) | Property Gross (Unrisked) Initially In Place (Mean) | Low Estimate (P90) | Best Estimate (P50) | Mean | High Estimate (P10) | Prospect Geological Chance of Discovery (2) | Risked Mean Property Gross (3) | Company Gross (4) | Company Net (5) |
|---|---|---|---|---|---|---|---|---|---|
| **KM** | | | | | | | | | |
| Deep | *189* | 19.6 | 34.1 | 37.9 | 59.7 | 99.7% | 21.4 | 21.4 | 7.5 |
| **Total** (6) | ***189*** | **19.6** | **34.1** | **37.9** | **59.7** | | **21.4** | **21.4** | **7.5** |

**Prospective Resources: Natural Gas (Bcf)**

| Prospect (1) | Property Gross (Unrisked) Initially In Place (Mean) | Low Estimate (P90) | Best Estimate (P50) | Mean | High Estimate (P10) | Prospect Geological Chance of Discovery (2) | Risked Mean Property Gross (3) | Company Gross (4) | Company Net (5) |
|---|---|---|---|---|---|---|---|---|---|
| **KM** | | | | | | | | | |
| Deep | *124* | 14.8 | 31.7 | 42.5 | 84.1 | 99.7% | 12.8 | 12.8 | 3.49 |
| **Total** (6) | ***124*** | **14.8** | **31.7** | **42.5** | **84.1** | | **12.8** | **12.8** | **3.5** |

(1) Separate zones within each prospect were added probabilistically using monte-carlo simulation.
(2) The prospect geological chance of discovery is based on the success of any one of the prospect zones and assumes independence and consequently is not equivalent to the [Risked Mean]/[Unrisked Mean]
(3) Prospect risked mean resources are equal to the summed product of the unrisked mean resources for each zone multiplied by the geological chance of success of each zone.
(4) Company gross prospective resources are based on the working interest share of the property gross prospective resources
(5) Company Net resources are based on the Mirach share of Cost Oil and Profit Oil revenues.
(6) The total may appear to differ from the sum of the underlying assets due to rounding differences.

**Table 13 – KM Deep Prospective Resources Summary**

### 4.9 Net Present Values of the Prospective Resources

Estimates of the net present value ("NPV") of the prospective resources were based on future production and revenue analyses. The net present value estimates are presented in US dollars and include an allowance for Indonesian taxes. The process of estimating values for prospective resources is much more complex than for reserves because of the wide range of likely outcomes that could occur following the drilling of an exploration well, especially where multiple zones may be prospective. A simplifying assumption was made to treat each zone as a separate prospect in the NPV calculations, which results in somewhat more conservative estimates of the NPV. In addition the information available to prepare revenue forecasts for the exploration prospect such as drilling costs, timing of exploration and development drilling and facility requirements is more limited at this time so the NPV's should be considered preliminary. A simplifying assumption was made to treat the development of the zones as three separate projects in the NPV calculations. The S8, S9 and S10 zones were assumed to be developed using the same wells with later recompletions where necessary. Similarly the S11, S12 and S13 were also combined into one notional development project. The Talang Akar is much deeper than the other zones and was therefore assumed to be developed separately.

The economic analysis employed in this report consisted of the preparation of a fiscal model for each notional development project containing production forecasts, price forecasts, operating and capital cost forecasts and government payments for the mean resource volumes. For the success case first oil was assumed to be one year after drilling the initial exploration well on the prospect. Well costs were varied in line with whether they are exploration or development wells and the likely reservoir depth and are presented in Table 14.

| | | Cost (US$ M) | |
|---|---|---|---|
| **Reservoir Group** | **Total Depth (m)** | **Exploration Well** | **Development Well** |
| S8, S9 & S10 | 800 | 1,000 | 800 |
| S11, S12, S13 | 1,100 | 1,300 | 1,100 |
| Talang Akar | 2,500 | 3,200 | 3,000 |

**Table 14 – KM Field Notional Deep Well Costs**

The notional development projects have been evaluated independently and do not account for possible facility cost savings that could occur if more than one group of zones is successful. The gas has only been valued in the case of the Talang Akar as for the Air Benekat the volumes are relatively small and most likely will be vented or used for in field power generation. The unrisked mean NPV was then combined with the dry hole cost and the geological chance of success to determine the risked mean NPV. Mirach's share of the resulting NPV's are presented in Table 15.

| Prospect /Project | Net Present Values at December 31, 2013 (US$ MM)(1)(2) Discounted At | | | | |
|---|---|---|---|---|---|
| | **0%** | **5%** | **10%** | **15%** | **20%** |
| Air Benekat - S8 to S10 | 110 | 80 | 61 | 47 | 37 |
| Air Benekat - S11 to S13 | 132 | 94 | 71 | 55 | 44 |
| Talang Akar | 11 | 8 | 5 | 4 | 2 |
| **Total (3)** | **253** | **182** | **136** | **105** | **84** |

(1) Based on forecast prices and costs at December 31, 2013 (see Price Forecast in Section 3).
(2) The net present values may not necessarily represent the fair market value of the resources.
(3) The total may appear to differ from the sum of the underlying assets due to rounding differences.

**Table 15 - KM Risked Mean Prospective Resources Net Present Value Summary (Mirach Share)**

The prospective projects are subject to the same fiscal terms outlined in Section 4.7.

## 5 GLOSSARY OF TECHNICAL TERMS AND ABBREVIATIONS

The following is a glossary of technical terms and a list of the abbreviations used in this report:

| Term/Abbreviation | Meaning |
|---|---|
| “2-D Seismic” | seismic data acquired in a grid of lines that is relatively broad spaced, and is processed in two dimensions |
| “3-D Seismic” | seismic data acquired in a grid that is relatively close-spaced and dense, and is processed in three dimensions |
| “AAPG” | American Association of Petroleum Geology |
| “abandonment” (of well) | a term to describe the sealing of a well with cement plugs, and removing the wellhead with no intention of re-entering the well |
| “AIM” | Alternative Investment Market on the London Stock Exchange |
| “anticline” | a hydrocarbon trap where the reservoir has a convex geometry |
| “API” | a specific gravity scale development by the American Petroleum Institute for measuring the relative density of various petroleum fluids, expressed in degrees |
| “appraisal well” | a well drilled as part of an appraisal drilling programme which is carried out to determine the physical extent, reserves and likely production rate of a field |
| “bbl” | one barrel of oil; 1 barrel = 35 Imperial gallons (approx.), or 159 litres (approx.); 7.5 barrels = 1 tonne (approximately depending upon the oil density); 6.29 barrels = 1 cubic metre |
| “bbl/MMcf” | barrels per million of cubic feet |
| “Bcf” | billion cubic feet |
| “block” | term commonly used to describe contract areas or tract, as in “block of land” |
| “bopd” | barrels of oil production per day |
| “bounding fault” | a fault that defines the limit of a prospect of hydrocarbon accumulation |
| “bpd” | barrels per day |
| “BS&W” | means base sediments and water |
| “bwpd” | barrels of water production per day |
| “Carboniferous” | geological period between 354 and 295 million years ago |
| “chance of discovery” | the chance that the potential accumulation will result in the discovery of petroleum |
| “clastic sequence” | rock series consisting of predominantly sedimentary rock made up of clasts (fragments) derived from pre-existing rocks transported and re-deposited before becoming lithified |
| “completion” | the operation of perforating, stimulating and equipping an oil or gas well |
| “condensate” | hydrocarbons which are in the gaseous state under reservoir conditions and which become liquid when temperature or pressure is reduced. A mixture of pentanes and higher hydrocarbons |
| “contingent resources” | Quantities of petroleum estimated, as at a given date, to be potentially recoverable from known accumulations, but applied project(s) are not yet considered mature enough for commercial development due to one of more contingencies |
| “Cretaceous” | geological strata formed during the period 140 million to 65 million years ago |
| “cost oil” | the sum of a party’s investment and operating costs recovered from the production of oil from the relevant field |
| “CPR” | Competent Person’s Report |

| Term/Abbreviation | Meaning |
|---|---|
| "dip" | the inclination of a horizontal structure from the horizontal |
| "discovery" | A defined term under PRMS. "A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons." |
| "DMO" | Domestic Market Obligation |
| "exploration phase" | the phase of operations which covers the search for oil or gas by carrying out detailed geological and geophysical surveys followed up where appropriate by exploratory drilling |
| "exploration well" | a well in an unproven area or prospect, may also be known as a "wildcat well" |
| "fault" | a break in the earth's crust where there has been displacement of one side relative to the other. Sometimes a layer of non-porous rock may be next to an oil-bearing porous interval along a fault and form a trap for the oil |
| "field" | a geographical area under which an oil or gas reservoir lies |
| "formation" | a unit of rock |
| "gas field" | a field containing natural gas but no oil |
| "graben" | a normally faulted elongate trough or block of rock, down-thrown on both sides |
| "GOC" | gas oil contact |
| "GOR" | gas oil ratio |
| "gross pay" | the total thickness of hydrocarbon bearing sediments |
| "GRV" | gross rock volume |
| "HKW" | highest known water |
| "hydrocarbon" | a compound containing only the elements hydrogen and carbon. May exist as a solid, a liquid or a gas. The term is mainly used in a catch-all sense for oil, gas and condensate |
| "Jurassic" | geological strata (or period) formed during the period from 144 million to 205 million years ago |
| "kg/m3" | Kilograms per cubic metre |
| "km" | kilometres |
| "KM" | Kampung Minyak |
| "KSO" or "Perjanjian KerjaSama Operasi" | a joint operations contract in the Indonesian language |
| "LKO" | lowest known oil |
| "LTO" | lowest tested oil |
| "mD" | milli Darcy (permeability) |
| "M" | thousands |
| "MM" | millions |
| "Mbbl" | thousands of barrels |
| "MMbbl" | millions of barrels |
| "Mcfpd" | thousands of cubic feet per day |
| "MMcfpd" | millions of cubic feet per day |
| "MFO" | marginal field operations |
| "natural gas" | gas, occurring naturally, and often found in association with crude petroleum |
| "net pay" | the total thickness of hydrocarbon bearing sediments that is classified as reservoir |

| Term/Abbreviation | Meaning |
|---|---|
| “oil” | a mixture of liquid hydrocarbons of different molecular weights |
| “oil field” | a geographic area under which an oil reservoir lies |
| “OOIP” | original oil in place |
| “operator” | the company that has legal authority to undertake petroleum operations. |
| “OWC” | oil water contact |
| “P10” | the term used to describe the volume of reserves defined as having a better than 10% chance of being technically and economically viable. |
| “P50” | the term used to describe the volume of reserves defined as having a better than 50% chance of being technically and economically viable. |
| “P90” | the term used to describe the volume of reserves defined as having a better than 90% chance of being technically and economically viable. |
| “permeability” | the property of a formation which quantifies the flow of a fluid through the pore spaces and into the wellbore |
| “Permian” | a geological period between 250 to 295 million years ago |
| “petroleum” | a generic name for hydrocarbons, including crude oil, natural gas liquids, natural gas and their products |
| “pool” | a individual and separate accumulation of petroleum in a reservoir |
| “porosity” | the percentage of void in a porous rock compared to the total rock volume |
| “PRMS” | Petroleum Resource Management System |
| “probabilistic” | a method of estimating an uncertain outcome whereby a range of values is used for each parameter in a calculation. Results are generally expressed as a range with an associated probability of occurrence |
| “profit oil” | means a party’s share of production from the relevant field in excess of Cost Oil |
| “property gross” | the total reserves or resources for the property |
| “prospective resources” | Quantities of petroleum estimated, as at a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development |
| “PSC” | a production sharing contract |
| “PVT” | pressure-volume-temperature relationship for fluid |
| “recompletion” | to repeat the initial “completion” of a well, at a later stage, to either enhance production from the existing “zone”, or to allow production from a new zone |
| “reserves” | generally the amount of economically recoverable oil or gas in a particular reservoir that is available for production |
| “reservoir” | the underground formation where oil and gas has accumulated. It consists of a porous and permeable rock to hold the oil or gas, and a cap rock that prevents its escape |
| “risked” | after accounting for chance of success or discovery |
| “saturated oil” | an oil at reservoir conditions that is at its “bubble point” |
| “SPE” | Society of Petroleum Engineers |
| “SPEE” | Society of Petroleum Evaluation Engineers |
| “stratigraphic trap” | a mode of trapping hydrocarbons which is not dependent on structural entrapment |
| “structural high” | an area where rocks have been elevated due to tectonic activity |
| “swabbing” | the process of mechanically producing a pressure drop in the wellbore by rapidly pulling out of the hole, usually with a cup shaped tool |

| Term/Abbreviation | Meaning |
|---|---|
| “Tcf” | trillion cubic feet |
| “TD” | total depth of a well, when drilling has finished |
| “Triassic” | geological period between 250 and 205 million years ago |
| “TVSS” | true vertical subsea (depth relative to a sea level datum) |
| “US$” | United States dollars |
| “US$ M” | thousands United States dollars |
| “US$ MM” | millions United States dollars |
| “USGS” | United States Geological Survey |
| “up-dip” | at a structurally higher elevation within dipping strata |
| “under-saturated oil” | an oil at reservoir conditions that is at a pressure above its “bubble point” (compare with “saturated oil”). Reductions in pressure can cause the oil to become saturated |
| “unrisked” | prior to taking into account the chance of discovery |
| “well log” | a record of geological formation penetrated during drilling, including technical details of the operation |
| “WPC” | World Petroleum Congress |
| “zone” | a general term meaning an interval or unit of rock. A zone in a well would be an interval typically defined by a top and bottom depth. A fault zone would be the unit of rock associated and the area around a fault |

## 6 PROFESSIONAL QUALIFICATIONS

McDaniel & Associates Consultants Ltd. has over 50 years of experience in the evaluation of oil and gas properties. McDaniel is registered with the Association of Professional Engineers and Geoscientists of Alberta (APEGA). All of the professionals involved in the preparation of this report have in excess of 5 years of experience in the evaluation of oil and gas properties. Mr. Bryan Emslie, Senior Vice President, Mr. Paul Taylor, Senior Petroleum Engineer and Mr. Kristian Jensen, Senior Geologist, all with McDaniel & Associates, were responsible for the preparation of this report. Mr. Emslie has over 30 years of experience in the evaluation of oil and gas properties and is a registered Professional Engineer with APEGA. Mr. Taylor has over 25 years of experience, is both a Chartered Petroleum Engineer with the UK Engineering Council and registered as a Foreign Licensee (Engineering) with APEGA. Mr. Kristian Jensen has in excess of 10 years and is a Fellow of the Royal Geological Society (UK). All of the persons involved in the preparation of this report and McDaniel & Associates are independent of Mirach.

This CPR was prepared by McDaniel & Associates Consultants Ltd. for securities reporting and to support banking and financing. It is not to be reproduced, distributed or made available, in whole or in part, to any person, company or organization other than Mirach for any other purpose without the knowledge and consent of McDaniel & Associates Consultants Ltd. We reserve the right to revise any opinions provided herein if any relevant data existing prior to preparation of this report was not made available or if any data provided is found to be erroneous.

Sincerely,

**McDANIEL & ASSOCIATES CONSULTANTS LTD.**
**APEGA PERMIT NUMBER: P3145**

for B. H. Emslie, P. Eng.
Senior Vice President

for P. M. Taylor, CEng MEI, P. Eng.
Associate

K. Jensen, FGS
Senior Geologist

BHE/PMT/KS:jep
[14-0038]

# APPENDIX

## ADDITIONAL TABLES & FIGURES

**Mirach Energy Limited** **Table 1**

**Kampung Minyak Field - Indonesia**

**Crude Oil Contingent Resource Summary - STC Zone**

**Effective December 31, 2013**

| Zone | STC | STC | STC | STC | STC | STC | STC | STC | STC | STC |
|---|---|---|---|---|---|---|---|---|---|---|
| Block | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | Total |
| Porosity, % | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 32 | |
| Water Saturation, % | 35 | 35 | 35 | 35 | 35 | 36 | 34 | 35 | 35 | |
| Oil Shrinkage, frac | 0.87 | 0.87 | 0.87 | 0.87 | 0.87 | 0.87 | 0.87 | 0.87 | 0.87 | |
| Original Oil-In Place, bbl/ac-ft | 1,420 | 1,427 | 1,429 | 1,423 | 1,429 | 1,414 | 1,442 | 1,447 | 1,403 | |
| Net Rock Volume, ac-ft | 8,259 | 3,716 | 3,066 | 2,206 | 3,031 | 5,841 | 1,587 | 705 | 1,446 | |
| Mapped Area, acres | 234 | 127 | 129 | 43 | 85 | 168 | 85 | 30 | 63 | |
| Average Net Thickness, ft | 35 | 29 | 24 | 51 | 36 | 35 | 19 | 23 | 23 | |
| Original Oil in Place, Mbbl | 11,730 | 5,301 | 4,381 | 3,139 | 4,333 | 8,258 | 2,288 | 1,020 | 2,029 | 42,479 |
| Cumulative Production, Mbbl | 1,309.9 | 205.1 | 1,011.1 | 284.7 | 798.3 | 915.5 | 85.6 | 0.4 | 42.8 | 4,653 |
| Cumulative Recovery, % | 11.2 | 3.9 | 23.1 | 9.1 | 18.4 | 11.1 | 3.7 | 0.0 | 2.1 | 11.0 |
| Average well spacing, ac/well | 8 | 21 | 8 | 4 | 5 | 42 | 28 | 30 | 31 | |
| Wells with Production | 31 | 6 | 17 | 10 | 16 | 4 | 3 | 1 | 2 | 90 |
| Existing Producers | 1 | - | 3 | 3 | 4 | - | - | - | - | 11 |
| End Dec 2013 Production Rate, bopd | 6.0 | - | 7.5 | 3.6 | 18.8 | - | - | - | - | 35.9 |
| Cum Oil per Prod. Well, Mbbl | 42 | 34 | 59 | 28 | 50 | 229 | 29 | 0.4 | 21 | 52 |
| **Low Contingent Resources (1C)** | | | | | | | | | | |
| Recovery Factor, % | 12.5 | 3.9 | 24.5 | 11.0 | 19.5 | 12.5 | 4.5 | 0.0 | 2.1 | 12.0 |
| Original Recoverable, Mbbl | 1,466 | 205 | 1,073 | 345 | 845 | 1,032 | 103 | 0.4 | 42.8 | 5,113 |
| Cumulative Production, Mbbl | 1,310 | 205 | 1,011 | 285 | 798 | 915 | 86 | 0.4 | 42.8 | 4,653 |
| Remaining Recoverable, Mbbl | 156 | - | 62 | 61 | 47 | 117 | 17 | - | - | 460 |
| **Best Estimate Contingent Resources (2C)** | | | | | | | | | | |
| Recovery Factor, % | 15.0 | 10.0 | 27.5 | 15.0 | 24.0 | 15.0 | 7.5 | 7.5 | 7.5 | 15.6 |
| Original Recoverable, Mbbl | 1,760 | 530 | 1,205 | 471 | 1,040 | 1,239 | 172 | 76 | 152 | 6,644 |
| Cumulative Production, Mbbl | 1,310 | 205 | 1,011 | 285 | 798 | 915 | 86 | 0 | 43 | 4,653 |
| Remaining Recoverable, Mbbl | 450 | 325 | 194 | 186 | 241 | 323 | 86 | 76 | 109 | 1,991 |
| **High Estimate Contingent Resources (3C)** | | | | | | | | | | |
| Recovery Factor, % | 20.0 | 15.0 | 30.0 | 25.0 | 26.0 | 20.0 | 12.5 | 12.5 | 12.5 | 20.4 |
| Original Recoverable, Mbbl | 2,346 | 795 | 1,314 | 785 | 1,126 | 1,652 | 286 | 127 | 254 | 8,685 |
| Cumulative Production, Mbbl | 1,310 | 205 | 1,011 | 285 | 798 | 915 | 86 | 0 | 43 | 4,653 |
| Remaining Recoverable, Mbbl | 1,036 | 590 | 303 | 500 | 328 | 736 | 200 | 127 | 211 | 4,032 |
| **Total 1C Well Requirements** | | | | | | | | | | |
| Production Wells Required | 10 | - | 5 | 5 | 4 | 8 | 3 | - | - | 35 |
| Average well spacing, ac/well | 7 | - | 7 | 3 | 5 | 14 | 17 | - | - | |
| Existing Wells Returned to Production | 6 | - | 3 | 2 | 3 | - | 1 | - | - | 15 |
| New Producers | 4 | - | 2 | 3 | 1 | 8 | 2 | - | - | 20 |
| Water Injectors Required | 6 | - | 3 | 1 | 2 | 4 | - | - | - | 16 |
| New Water Injectors | 1 | - | - | - | - | 3 | - | - | - | 4 |
| Average Well Productivity, bopd/w | 8 | - | 10 | 10 | 10 | 10 | 5 | - | - | 9 |
| Total Pool Productivity, bopd | 80 | - | 50 | 50 | 40 | 80 | 15 | - | - | 315 |
| Remaining Res per Prod. Well, Mbbl | 16 | - | 12 | 12 | 12 | 15 | 6 | - | - | 13 |
| Resource Life Index, years | 5 | - | 3 | 3 | 3 | 4 | 3 | - | - | 4 |
| **Total 2C Well Requirements** | | | | | | | | | | |
| Production Wells Required | 16 | 8 | 7 | 4 | 6 | 11 | 3 | 2 | 3 | 60 |
| Average well spacing, ac/well | 6 | 11 | 7 | 4 | 5 | 11 | 17 | 10 | 16 | |
| Existing Wells Returned to Production | 9 | 2 | 5 | 4 | 5 | - | 1 | - | 1 | 27 |
| New Producers | 7 | 6 | 2 | - | 1 | 11 | 2 | 2 | 2 | 33 |
| Water Injectors Required | 8 | 4 | 4 | 1 | 3 | 6 | 3 | 1 | 2 | 32 |
| New Water Injectors | 2 | 1 | - | - | 1 | 1 | 1 | - | - | 6 |
| Average Well Productivity, bopd/w | 20 | 15 | 30 | 30 | 30 | 20 | 15 | 15 | 15 | 22 |
| Total Pool Productivity, bopd | 320 | 120 | 210 | 120 | 180 | 220 | 45 | 30 | 45 | 1,290 |
| Remaining Res per Prod. Well, Mbbl | 28 | 41 | 28 | 47 | 40 | 29 | 29 | 38 | 36 | 33 |
| Resource Life Index, years | 4 | 7 | 3 | 4 | 4 | 4 | 5 | 7 | 7 | 4 |
| **Total 3C Well Requirements** | | | | | | | | | | |
| Production Wells Required | 19 | 11 | 9 | 4 | 7 | 14 | 6 | 2 | 4 | 76 |
| Average well spacing, ac/well | 6 | 8 | 7 | 4 | 5 | 9 | 11 | 15 | 13 | |
| Existing Wells Returned to Production | 12 | 2 | 7 | 4 | 6 | - | 1 | 1 | 1 | 34 |
| New Producers | 7 | 9 | 2 | - | 1 | 14 | 5 | 1 | 3 | 42 |
| Water Injectors Required | 9 | 5 | 5 | 2 | 3 | 7 | 3 | 1 | 3 | 38 |
| New Water Injectors | 2 | 1 | 1 | - | 1 | 1 | 1 | - | 1 | 8 |
| Average Well Productivity, bopd/w | 30 | 25 | 40 | 50 | 40 | 30 | 20 | 25 | 20 | 31 |
| Total Pool Productivity, bopd | 570 | 275 | 360 | 200 | 280 | 420 | 120 | 50 | 80 | 2,355 |
| Remaining Res per Prod. Well, Mbbl | 55 | 54 | 34 | 125 | 47 | 53 | 33 | 64 | 53 | 53 |
| Resource Life Index, years | 5 | 6 | 2 | 7 | 3 | 5 | 5 | 7 | 7 | 5 |

**Mirach Energy Limited**
**Kampung Minyak Field - Indonesia**
**Crude Oil Contingent Resource Summary - S1-8 Zone**
**Effective December 31, 2013**

**Table 2**

| Zone<br>Block | S1-8<br>1 | S1-8<br>2 | S1-8<br>3 | S1-8<br>4 | S1-8<br>5 | S1-8<br>6 | S1-8<br>7 | S1-8<br>8 | S1-8<br>9 | S1-8<br>Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Net Rock Volume, ac-ft | 636 | 3,582 | 3,038 | 851 | 1,128 | 1,621 | 7,968 | 713 | 202 | |
| Mapped Area, acres | 99 | 71 | 80 | 19 | 31 | 58 | 142 | 53 | 53 | |
| Average Net Thickness, ft | 6 | 51 | 38 | 45 | 37 | 28 | 56 | 14 | 4 | |
| Original Oil in Place, Mbbl | 748 | 4,022 | 3,489 | 966 | 1,197 | 1,867 | 9,046 | 862 | 266 | 22,462 |
| Cumulative Production, Mbbl | 9.1 | 287.3 | 741.3 | 75.9 | 877.7 | 685.0 | 2,995.2 | 852.8 | 48.8 | 6,573 |
| Cumulative Recovery, % | 1.2 | 7.1 | 21.2 | 7.9 | 73.3 | 36.7 | 33.1 | 98.9 | 18.4 | 29.3 |
| Wells with Production | 99 | 4 | 3 | 3 | 2 | 3 | 3 | 4 | 18 | 139 |
| Average well spacing, ac/well | 1 | 17 | 31 | 7 | 14 | 18 | 46 | 15 | 3 | |
| Existing Producers | - | - | 3 | 1 | 3 | 2 | 1 | 1 | - | 11 |
| End Dec 2013 Production Rate, bopd | - | - | 24.5 | 21.0 | 38.9 | 4.2 | 1.8 | 1.4 | - | 91.7 |
| Cum Oil per Prod. Well, Mbbl | 0 | 69 | 289 | 28 | 399 | 214 | 972 | 243.3 | 3 | 47 |
| **Low Contingent Resources (1C)** | | | | | | | | | | |
| Recovery Factor, % | 1.2 | 8.1 | 22.0 | 10.7 | 75.7 | 37.3 | 33.2 | 99.0 | 18.4 | 29.9 |
| Original Recoverable, Mbbl | 9 | 327 | 769 | 103 | 906 | 695 | 2,999 | 853.8 | 48.8 | 6,712 |
| Cumulative Production, Mbbl | 9 | 287 | 741 | 76 | 878 | 685 | 2,995 | 852.8 | 48.8 | 6,573 |
| Remaining Recoverable, Mbbl | - | 40 | 28 | 27 | 28 | 10 | 4 | 1 | - | 139 |
| **Best Estimate Contingent Resources (2C)** | | | | | | | | | | |
| Recovery Factor, % | 1.2 | 9.8 | 23.2 | 14.1 | 80.1 | 41.6 | 35.4 | 99.1 | 18.4 | 32.0 |
| Original Recoverable, Mbbl | 9 | 394 | 809 | 136 | 959 | 776 | 3,201 | 855 | 49 | 7,187 |
| Cumulative Production, Mbbl | 9 | 287 | 741 | 76 | 878 | 685 | 2,995 | 853 | 49 | 6,573 |
| Remaining Recoverable, Mbbl | - | 107 | 68 | 60 | 81 | 91 | 206 | 2 | - | 614 |
| **High Estimate Contingent Resources (3C)** | | | | | | | | | | |
| Recovery Factor, % | 1.2 | 13.7 | 25.2 | 18.8 | 88.8 | 49.3 | 41.9 | 99.2 | 18.4 | 36.9 |
| Original Recoverable, Mbbl | 9 | 553 | 880 | 181 | 1,063 | 920 | 3,790 | 856 | 49 | 8,299 |
| Cumulative Production, Mbbl | 9 | 287 | 741 | 76 | 878 | 685 | 2,995 | 853 | 49 | 6,573 |
| Remaining Recoverable, Mbbl | - | 265 | 138 | 105 | 185 | 235 | 794 | 3 | - | 1,726 |
| **Total 1C Well Requirements** | | | | | | | | | | |
| Production Wells Required | - | 3 | 4 | 2 | 3 | 3 | 3 | 1 | - | 19 |
| Average well spacing, ac/well | - | 10 | 22 | 5 | 14 | 14 | 46 | 15 | - | |
| Existing Wells Returned to Production | - | - | 3 | 1 | 3 | 2 | 3 | 1 | - | 13 |
| New Producers | - | 3 | 1 | 1 | - | 1 | - | - | - | 6 |
| Water Injectors Required | - | - | - | - | - | - | - | - | - | - |
| New Water Injectors | - | - | - | - | - | - | - | - | - | - |
| Average Well Productivity, bopd/w | - | 18 | 10 | 19 | 13 | 5 | 2 | 1 | - | 10 |
| Total Pool Productivity, bopd | - | 55 | 38 | 37 | 39 | 14 | 6 | 1 | - | 190 |
| Remaining Res per Prod. Well, Mbbl | - | 13 | 7 | 14 | 9 | 3 | 1 | 1 | - | 7 |
| Resource Life Index, years | - | 2 | 2 | 2 | 2 | 2 | 2 | 2 | - | 2 |
| **Total 2C Well Requirements** | | | | | | | | | | |
| Production Wells Required | - | 5 | 6 | 2 | 4 | 9 | 11 | 1 | - | 38 |
| Average well spacing, ac/well | - | 10 | 22 | 5 | 10 | 8 | 18 | 15 | - | |
| Existing Wells Returned to Production | - | 2 | 5 | 1 | 3 | 5 | 6 | 1 | - | 23 |
| New Producers | - | 3 | 1 | 1 | 1 | 4 | 5 | - | - | 15 |
| Water Injectors Required | - | 1 | 1 | 1 | 1 | 1 | 2 | 1 | - | 8 |
| New Water Injectors | - | - | - | - | - | - | - | - | - | - |
| Average Well Productivity, bopd/w | - | 15 | 8 | 21 | 14 | 7 | 13 | 1 | - | 11 |
| Total Pool Productivity, bopd | - | 73 | 47 | 41 | 55 | 62 | 141 | 1 | - | 421 |
| Remaining Res per Prod. Well, Mbbl | - | 21 | 11 | 30 | 20 | 10 | 19 | 2 | - | 16 |
| Resource Life Index, years | - | 4 | 4 | 4 | 4 | 4 | 4 | 4 | - | 4 |
| **Total 3C Well Requirements** | | | | | | | | | | |
| Production Wells Required | - | 8 | 10 | 3 | 7 | 12 | 21 | 1 | - | 62 |
| Average well spacing, ac/well | - | 9 | 22 | 5 | 7 | 6 | 10 | 15 | - | |
| Existing Wells Returned to Production | - | 4 | 9 | 2 | 5 | 6 | 10 | 1 | - | 37 |
| New Producers | - | 4 | 1 | 1 | 2 | 6 | 11 | - | - | 25 |
| Water Injectors Required | - | 2 | 2 | 2 | 2 | 2 | 2 | 2 | - | 14 |
| New Water Injectors | - | - | - | - | - | - | - | - | - | - |
| Average Well Productivity, bopd/w | - | 15 | 6 | 16 | 12 | 9 | 17 | 1 | - | 13 |
| Total Pool Productivity, bopd | - | 121 | 63 | 48 | 84 | 107 | 363 | 1 | - | 788 |
| Remaining Res per Prod. Well, Mbbl | - | 33 | 14 | 35 | 26 | 20 | 38 | 3 | - | 28 |
| Resource Life Index, years | - | 6 | 6 | 6 | 6 | 6 | 6 | 6 | - | 6 |

**Table 3**

## Mirach Energy Limited
## Kampung Minyak Field - Indonesia
## Crude Oil Contingent Resource Overall Summary
**Effective December 31, 2013**

| Zone<br>Block | STC<br>1-9 | S1-8<br>1-9 | Others<br>1-9 | Total |
|---|---|---|---|---|
| Original Oil in Place, Mbbl | 42,479 | 22,462 | | 64,940 |
| Cumulative Production, Mbbl | 4,653 | 6,573 | 689 | 11,916 |
| Cumulative Recovery, % | 11.0 | 29.3 | | 18.3 |
| Wells with Production | 90 | 152 | 29 | 271 |
| Existing Producers | 11 | 11 | - | 22 |
| End Dec 2013 Production Rate, bopd | 36 | 92 | - | 128 |
| Cum Oil per Prod. Well, Mbbl | 52 | 43 | 24 | 44 |
| **Low Contingent Resources (1C)** | | | | |
| Recovery Factor, % | 12.0 | 29.9 | | 19.3 |
| Original Recoverable, Mbbl | 5,113 | 6,712 | 689 | 12,514 |
| Cumulative Production, Mbbl | 4,653 | 6,573 | 689 | 11,916 |
| Remaining Recoverable, Mbbl | 460 | 139 | - | 599 |
| **Best Estimate Contingent Resources (2C)** | | | | |
| Recovery Factor, % | 15.6 | 32.0 | | 22.4 |
| Original Recoverable, Mbbl | 6,644 | 7,187 | 689 | 14,521 |
| Cumulative Production, Mbbl | 4,653 | 6,573 | 689 | 11,916 |
| Remaining Recoverable, Mbbl | 1,991 | 614 | - | 2,605 |
| **High Estimate Contingent Resources (3C)** | | | | |
| Recovery Factor, % | 20.4 | 36.9 | | 27.2 |
| Original Recoverable, Mbbl | 8,685 | 8,299 | 689 | 17,674 |
| Cumulative Production, Mbbl | 4,653 | 6,573 | 689 | 11,916 |
| Remaining Recoverable, Mbbl | 4,032 | 1,726 | - | 5,758 |
| **Total 1C Well Requirements** | | | | |
| Production Wells Required | 35 | 19 | - | 54 |
| Existing Wells Returned to Production | 15 | 13 | - | 28 |
| New Producers | 20 | 6 | - | 26 |
| Water Injectors Required | 16 | - | - | 16 |
| New Water Injectors | 4 | - | - | 4 |
| Average Well Productivity, bopd/w | 9 | 10 | - | 9 |
| Total Pool Productivity, bopd | 315 | 190 | - | 505 |
| Remaining Res per Prod. Well, Mbbl | 13 | 7 | - | 11 |
| Resource Life Index, years | 4 | 2 | - | 3 |
| **Total 2C Well Requirements** | | | | |
| Production Wells Required | 60 | 38 | - | 98 |
| Existing Wells Returned to Production | 27 | 23 | - | 50 |
| New Producers | 33 | 15 | - | 48 |
| Water Injectors Required | 32 | 8 | - | 40 |
| New Water Injectors | 6 | - | - | 6 |
| Average Well Productivity, bopd/w | 22 | 11 | - | 17 |
| Total Pool Productivity, bopd | 1,290 | 421 | - | 1,711 |
| Remaining Res per Prod. Well, Mbbl | 33 | 16 | - | 27 |
| Resource Life Index, years | 4 | 4 | - | 4 |
| **Total 3C Well Requirements** | | | | |
| Production Wells Required | 76 | 62 | - | 138 |
| Existing Wells Returned to Production | 34 | 37 | - | 71 |
| New Producers | 42 | 25 | - | 67 |
| Water Injectors Required | 38 | 14 | - | 52 |
| New Water Injectors | 8 | - | - | 8 |
| Average Well Productivity, bopd/w | 31 | 13 | - | 23 |
| Total Pool Productivity, bopd | 2,355 | 788 | - | 3,143 |
| Remaining Res per Prod. Well, Mbbl | 53 | 28 | - | 42 |
| Resource Life Index, years | 5 | 6 | - | 5 |

**Mirach Energy Limited** **Table 4**
**Kampung Minyak Field - Indonesia**
**Summary of Prospective Resource Estimates - Property Gross Values**
**as of December 31, 2013**

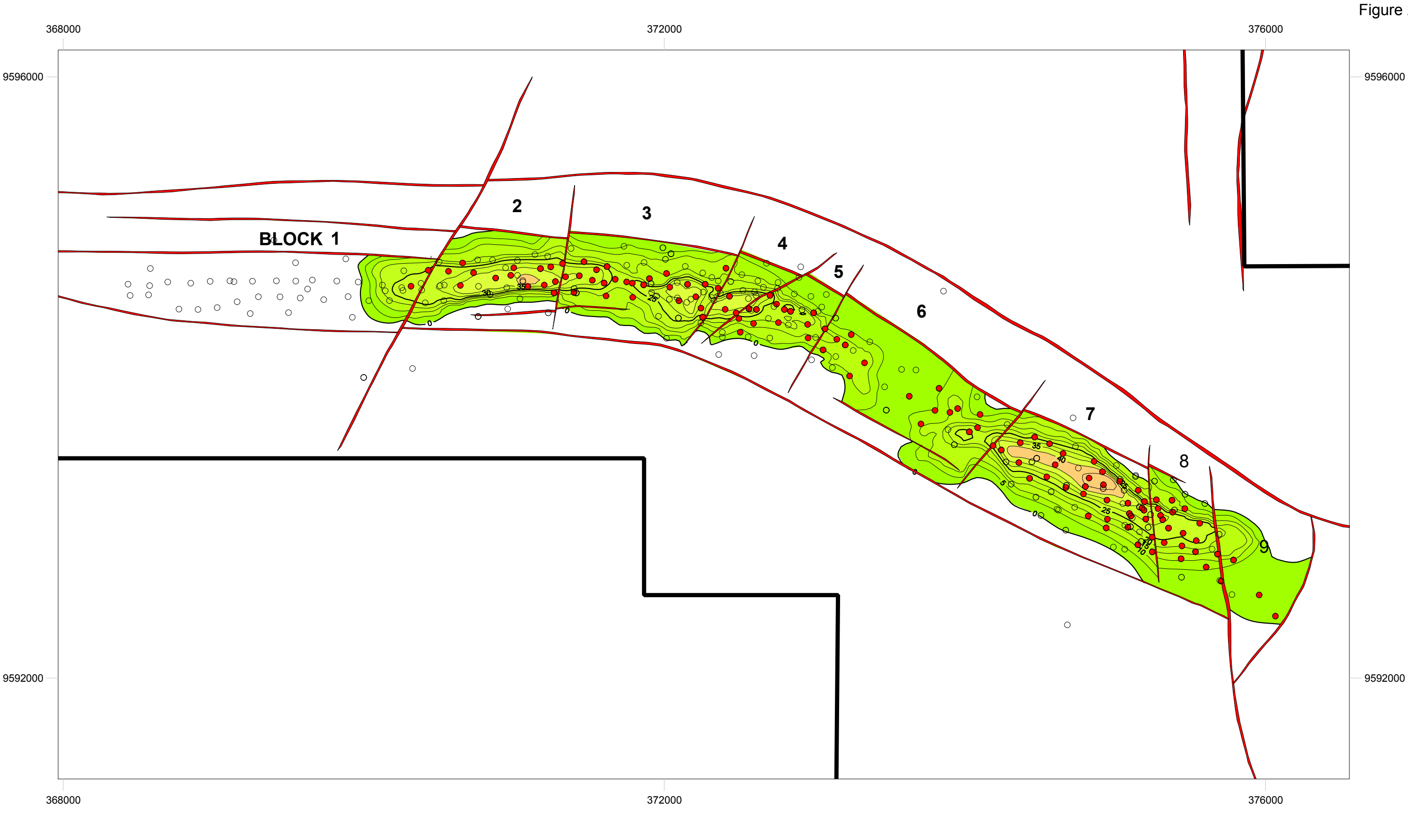
| **Prospective Resources - Crude Oil** | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | **Prospective Resources - Unrisked (1) (2) (3) (4)** | | | | **Risked Resources** | **Chance of** |
| | | **Low** | **Best Est.** | **Mean** | **High** | **Mean** | **Discovery** |
| **Lead/Prospect** | **Zone** | Mbbl | Mbbl | Mbbl | Mbbl | Mbbl | **%** |
| Kampung Minyak Deep | S8 | 321 | 1,248 | 2,052 | 4,709 | 1,477 | 72 |
| Kampung Minyak Deep | S9 | 456 | 2,181 | 4,183 | 10,164 | 1,882 | 45 |
| Kampung Minyak Deep | S10 | 1,751 | 5,710 | 8,334 | 18,073 | 6,000 | 72 |
| Kampung Minyak Deep | S11 | 787 | 2,727 | 4,028 | 8,769 | 2,175 | 54 |
| Kampung Minyak Deep | S12 | 1,248 | 5,500 | 9,615 | 22,310 | 6,058 | 63 |
| Kampung Minyak Deep | S13 | 1,060 | 3,733 | 5,633 | 12,577 | 3,042 | 54 |
| Kampung Minyak Deep | Talang Akar | 605 | 2,405 | 4,015 | 9,237 | 803 | 20 |
| **Kampung Minyak Deep** | **Crude Oil Total** | **19,602** | **34,125** | **37,861** | **59,732** | **21,438** | |

| **Prospective Resources - Natural Gas** | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | **Prospective Resources - Unrisked (1) (2) (3) (4)** | | | | **Risked Resources** | **Chance of** |
| | | **Low** | **Best Est.** | **Mean** | **High** | **Mean** | **Discovery** |
| **Lead/Prospect** | **Zone** | MMcf | MMcf | MMcf | MMcf | MMcf | **%** |
| Kampung Minyak Deep | S8 | 56 | 230 | 379 | 867 | 273 | 72 |
| Kampung Minyak Deep | S9 | 89 | 441 | 875 | 2,139 | 394 | 45 |
| Kampung Minyak Deep | S10 | 424 | 1,420 | 2,121 | 4,643 | 1,527 | 72 |
| Kampung Minyak Deep | S11 | 238 | 861 | 1,305 | 2,870 | 705 | 54 |
| Kampung Minyak Deep | S12 | 427 | 1,928 | 3,430 | 8,017 | 2,161 | 63 |
| Kampung Minyak Deep | S13 | 468 | 1,679 | 2,602 | 5,842 | 1,405 | 54 |
| Kampung Minyak Deep | Talang Akar | 5,781 | 20,472 | 31,834 | 72,804 | 6,367 | 20 |
| **Kampung Minyak Deep** | **Natural Gas Total** | **14,811** | **31,706** | **42,546** | **84,130** | **12,831** | |

(1) There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be economically viable or technically feasible to produce any portion of the resources.
(2) These are partially risked prospective resources that have been risked for chance of discovery, but have not been risked for chance of development.
(3) Individual zone estimates statistically aggregated to the prospect/lead level.
(4) Natural gas prospective resources for the S8 to S13 are unlikley to be commercial if discovered


Figure 1
368000
372000
376000
9596000
9592000
BLOCK 1
2
3
4
5
6
7
8
9
Well Legend
Oil producer
Oil well
Gas producer
Gas well
Status unknown
Abandoned
Injector (Water, Planned)
Injector (Gas, Planned)
Drilling location
Map Abbreviations
OWC - Oil Water Contact
GOC - Gas Oil Contact
GWC - Gas Water Contact
NT - Not Tested
NP - Not Present
NDE - Not Deep Enough
ODT - Oil Down To
GDT - Gas Down To
WUT - Water Up To
N
W
E
S
1 0 1 2 3 km
McDaniel
& Associates Consultants Ltd
Mirach Energy Ltd.
Kampung Minyak - Indonesia
Net Pay Map
STC Sands
(Upper and Lower)
KSJ
Units – metres
12 March, 2014

Figure 2




| Well Legend | Map Abbreviations |
|---|---|
| Oil producer | OWC - Oil Water Contact |
| Oil well | GOC - Gas Oil Contact |
| Gas producer | GWC - Gas Water Contact |
| Gas well | NT - Not Tested |
| Status unknown | NP - Not Present |
| Abandoned | NDE - Not Deep Enough |
| Injector (Water, Planned) | ODT - Oil Down To |
| Injector (Gas, Planned) | GDT - Gas Down To |
| Drilling location | WUT - Water Up To |

McDaniel & Associates Consultants Ltd.

Mirach Energy Ltd.
Kampung Minyak - Indonesia
Net Pay Map
S1 to S8 Sands

| KSJ | Units – metres | 12 March, 2014 |
|---|---|---|

Figure 3

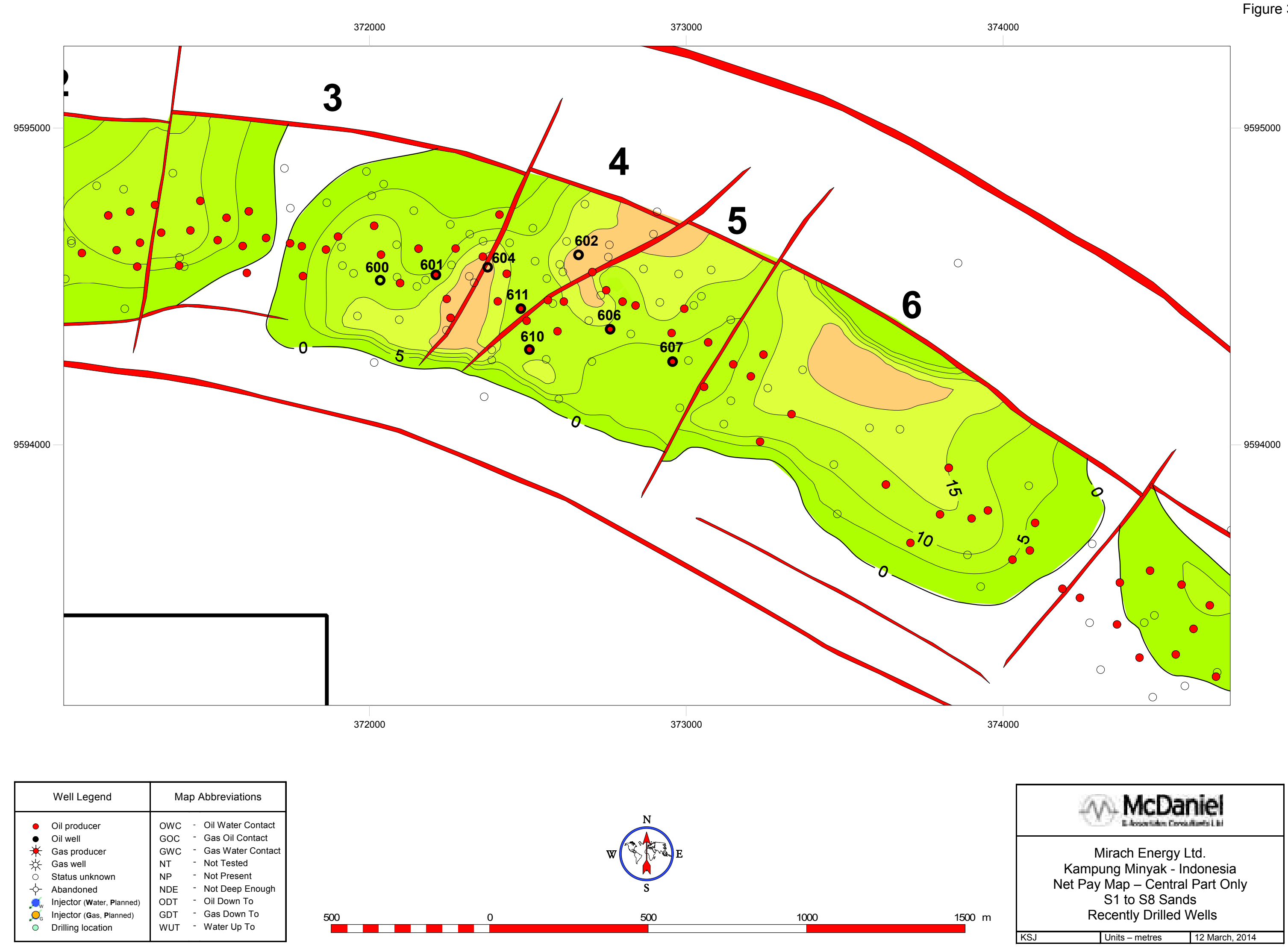

372000
373000
374000
9595000
9594000
3
4
5
6
600
601
604
602
611
610
606
607
0
5
10
15
Well Legend
Oil producer
Oil well
Gas producer
Gas well
Status unknown
Abandoned
Injector (Water, Planned)
Injector (Gas, Planned)
Drilling location
Map Abbreviations
OWC - Oil Water Contact
GOC - Gas Oil Contact
GWC - Gas Water Contact
NT - Not Tested
NP - Not Present
NDE - Not Deep Enough
ODT - Oil Down To
GDT - Gas Down To
WUT - Water Up To
N
S
W
E
500 0 500 1000 1500 m
McDaniel
Mirach Energy Ltd.
Kampung Minyak - Indonesia
Net Pay Map – Central Part Only
S1 to S8 Sands
Recently Drilled Wells
KSJ
Units – metres
12 March, 2014

Figure 4

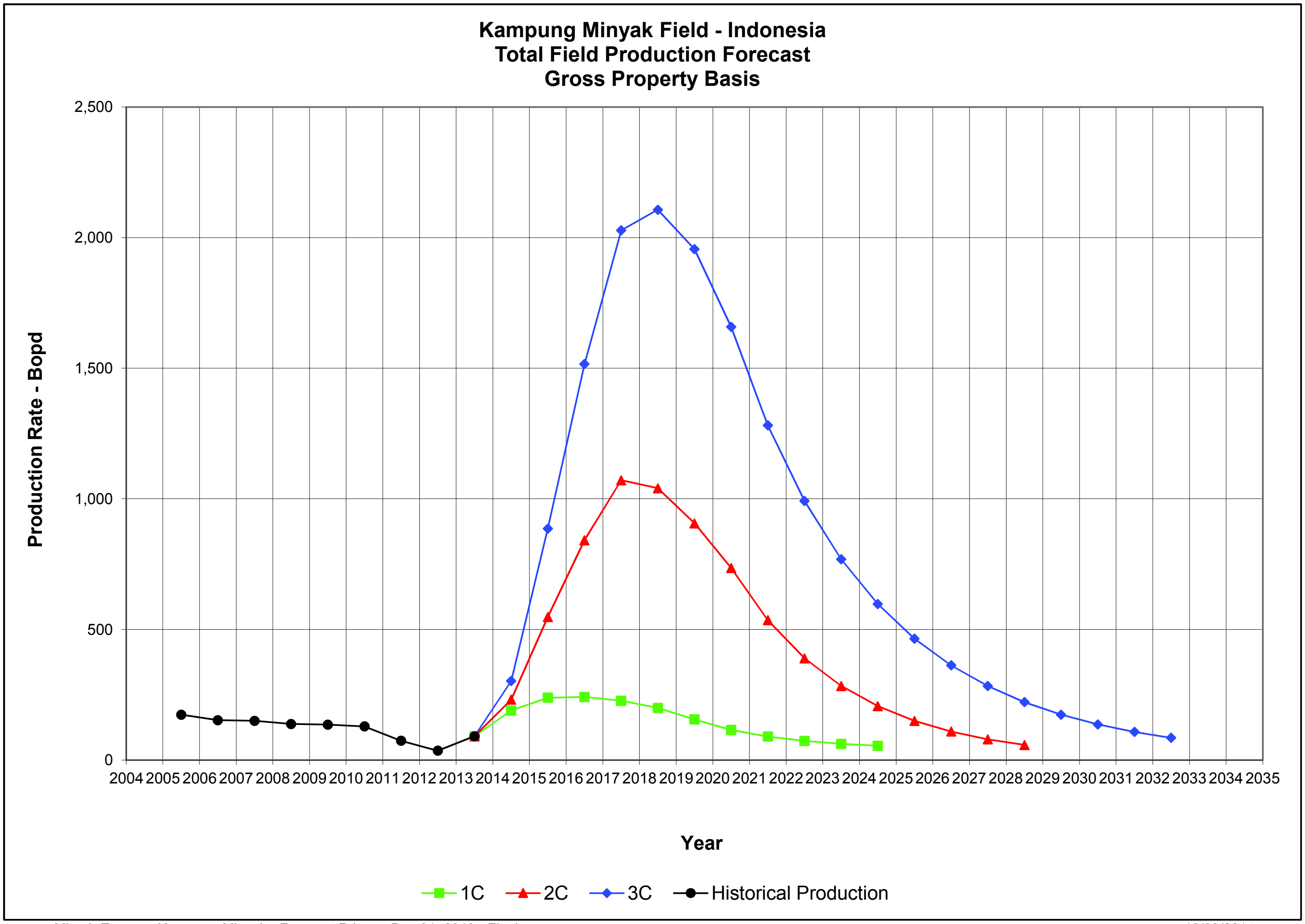
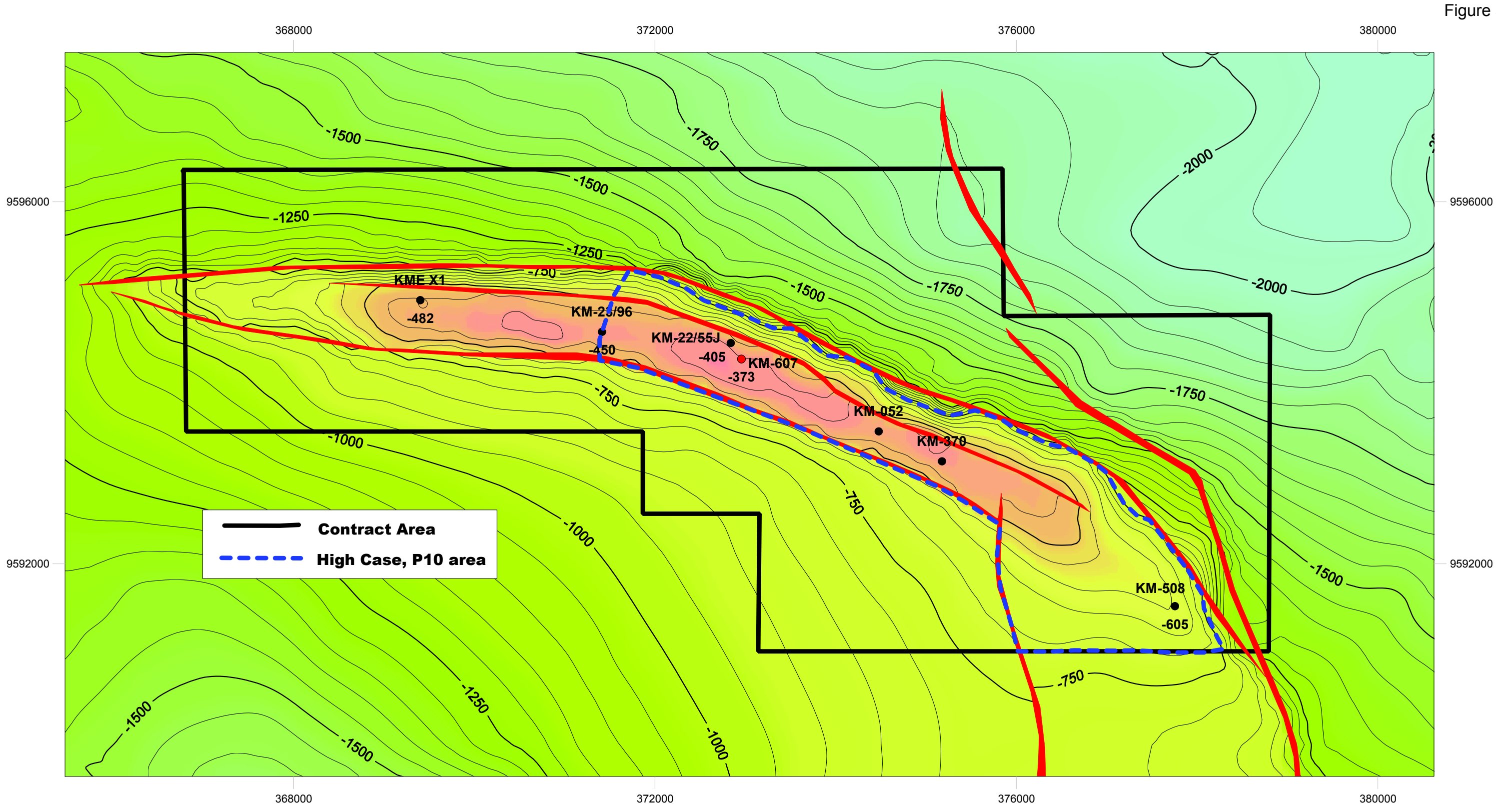
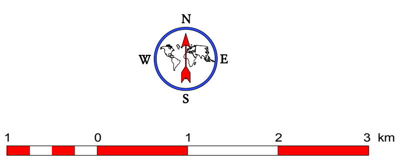

Kampung Minyak Field - Indonesia
Total Field Production Forecast
Gross Property Basis
Production Rate - Bopd
2,500
2,000
1,500
1,000
500
0
2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035
Year
1C
2C
3C
Historical Production

Figure 5




| Well Legend | Map Abbreviations |
|---|---|
| Oil producer | OWC - Oil Water Contact |
| Oil well | GOC - Gas Oil Contact |
| Gas producer | GWC - Gas Water Contact |
| Gas well | NT - Not Tested |
| Status unknown | NP - Not Present |
| Abandoned | NDE - Not Deep Enough |
| Injector (Water, Planned) | ODT - Oil Down To |
| Injector (Gas, Planned) | GDT - Gas Down To |
| Drilling location | WUT - Water Up To |

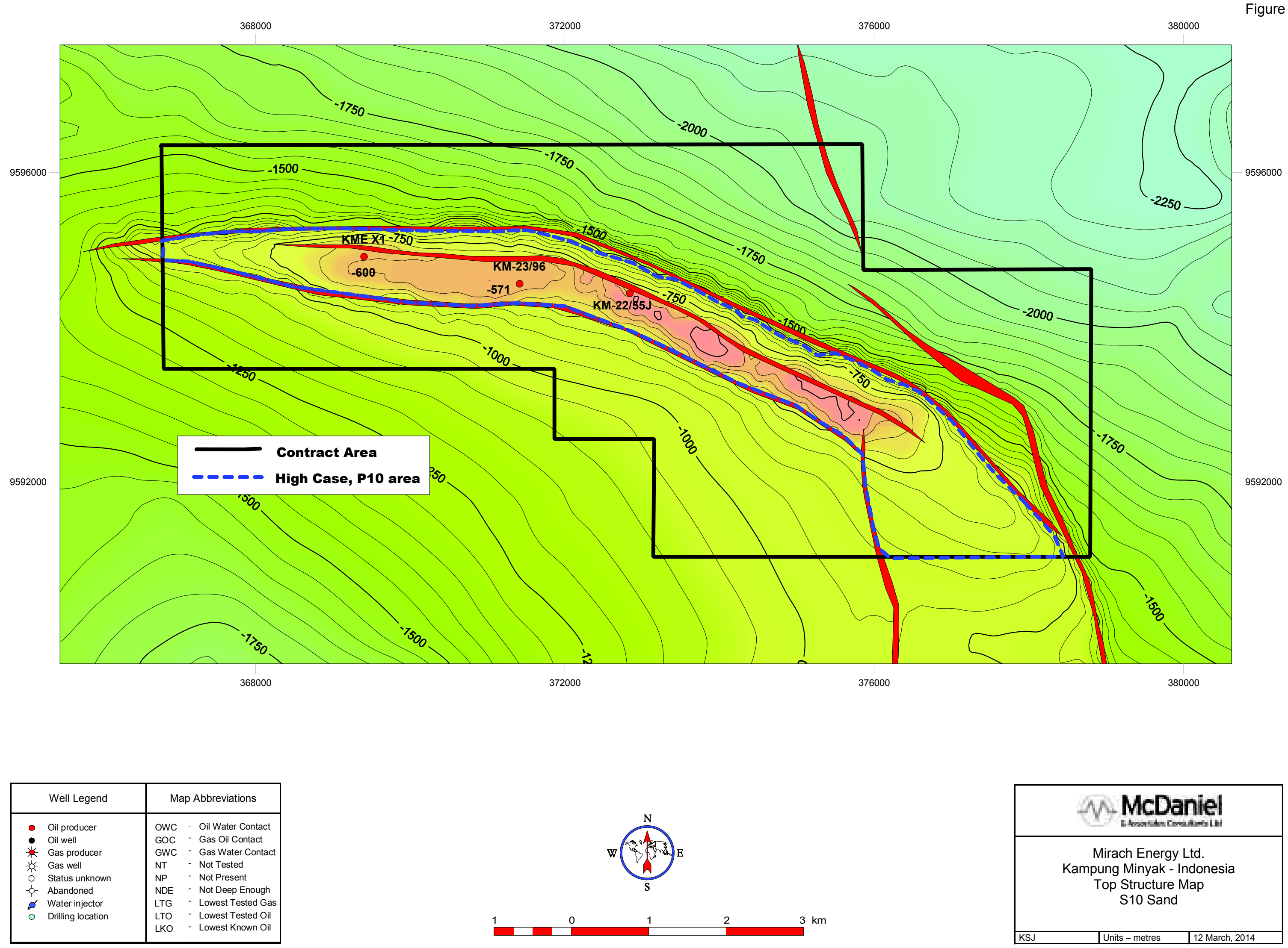



McDaniel & Associates Consultants Ltd.

Mirach Energy Ltd.
Kampung Minyak - Indonesia
Top Structure Map
S8 Sand

| KSJ | Units – metres | 12 March, 2014 |
|---|---|---|

Figure 6

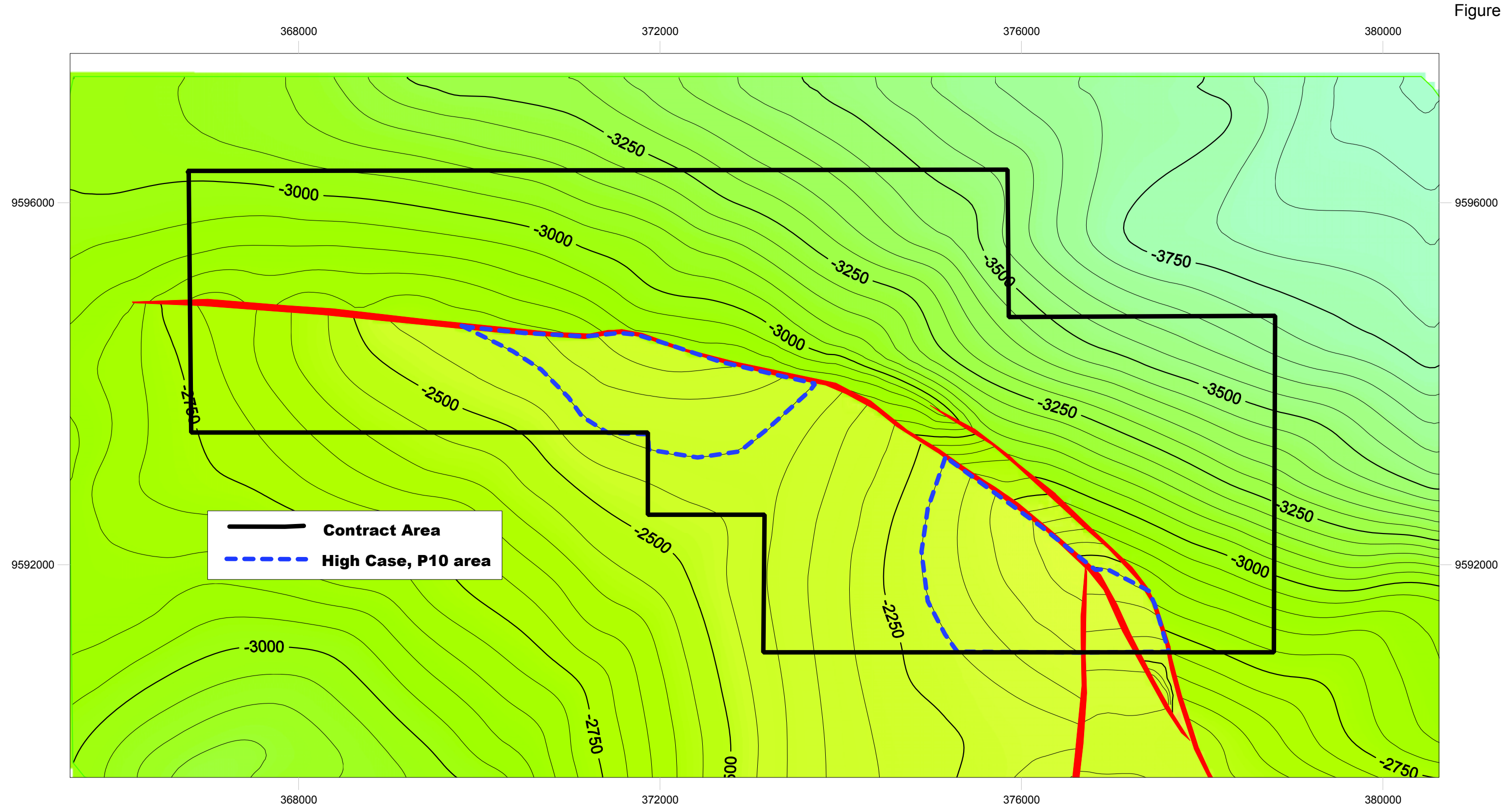



McDaniel & Associates Consultants Ltd.

Mirach Energy Ltd.
Kampung Minyak - Indonesia
Top Structure Map
S10 Sand

| KSJ | Units – metres | 12 March, 2014 |
|---|---|---|

Figure 7




| Well Legend | Map Abbreviations |
|---|---|
| Oil producer | OWC - Oil Water Contact |
| Oil well | GOC - Gas Oil Contact |
| Gas producer | GWC - Gas Water Contact |
| Gas well | NT - Not Tested |
| Status unknown | NP - Not Present |
| Abandoned | NDE - Not Deep Enough |
| Water injector | LTG - Lowest Tested Gas |
| Drilling location | LTO - Lowest Tested Oil |
| | LKO - Lowest Known Oil |

N
W E
S

1 0 1 2 3 km

McDaniel & Associates Consultants Ltd

Mirach Energy Ltd.
Kampung Minyak - Indonesia
Top Structure Map
Talang Akar Formation

| KSJ | Units – metres | 12 March, 2014 |
|---|---|---|