Private and confidential

# Competent Person's Report
## The non-core Asian portfolio of Santos

Oil field in Vietnam & gas fields in Indonesia

On behalf of Ophir Energy plc

3 August 2018

17.0177

decisions with confidence

## Declaration

Ophir Energy plc ("Ophir") has commissioned RISC (UK) Limited ("RISC") to provide an independent valuation of the Reserves and a review of the Contingent Resources of Santos Limited's ("Santos") Asian assets to form a Competent Person's Report.

The assessment of petroleum assets is subject to uncertainty because it involves judgments on many variables that cannot be precisely assessed, including reserves, future oil and gas production rates, the costs associated with producing these volumes, access to product markets, product prices and the potential impact of fiscal/regulatory changes.

The statements and opinions attributable to RISC are given in good faith and in the belief that such statements are neither false nor misleading. In carrying out its tasks, RISC has considered and relied upon information obtained from a data room as well as information in the public domain. The information provided to RISC has included both hard copy and electronic information supplemented with discussions between RISC and key Ophir staff.

Whilst every effort has been made to verify data and resolve apparent inconsistencies, neither RISC nor its servants accept any liability for its accuracy, nor do we warrant that our enquiries have revealed all the matters, which an extensive examination may disclose. RISC have not independently verified property title, encumbrances, regulations that apply to these assets. RISC has also not audited the opening balances at the valuation date of past recovered and unrecovered development and exploration costs, undepreciated past development costs and tax losses.

RISC believes its review and conclusions are sound, but no warranty of accuracy or reliability is given to its conclusions.

RISC has no pecuniary interest, other than to the extent of the professional fees receivable for the preparation of this report, or other interest in the assets evaluated, that could reasonably be regarded as affecting our ability to give an unbiased view of these assets.

RISC's review was carried out only for the purpose referred to above and may not have relevance in other contexts.

**RISC (UK) Limited**
Rex House,
4-12 Regent Street
London.
SW1Y 4PE
United Kingdom

**Ophir Energy plc**
123 Victoria Street
London
SW1E 6DE
United Kingdom

# 1. Executive Summary

Ophir Energy plc (Ophir) is an independent upstream oil and gas company with production, development and exploration assets in Asia and exploration, appraisal and production assets in Africa. Ophir is listed on the London Stock Exchange (LSE).

Ophir retained RISC (UK) Limited (RISC) to provide a Competent Person's Report (CPR) on Santos Limited's (Santos) Asian assets, compliant with the requirements of a Class 1 transaction under the Listing Rules of the London Stock Exchange, for inclusion in a circular. The assets are the Santos operated Sampang PSC offshore East Java, Indonesia which contains the Wortel and Oyong gas fields, the Santos operated Madura Offshore PSC East Java, Indonesia which contains the Peluang and Maleo gas fields and Block 12W offshore Vietnam operated by Premier Oil plc, which contains the Chim Sáo and Dua oil fields. Over 70% of the total value is attributable to the Chim Sáo and Dua oil fields. The assets are summarised in Table 1-1.

**Table 1-1: Santos Asian assets summary**

| Asset | | Operator | Working Interest | Status | Licence expiry date | Licence area (km$^2$) | Comments |
|---|---|---|---|---|---|---|---|
| Country | PSC | | | | | | |
| Indonesia | Sampang | Santos | 45% | Production | 04/12/2027 | 534.30 | |
| | Madura | Santos | 67.5% | Production | 04/12/2027 | 849.00 | Santos has a 77.5% WI in the undeveloped Meliwis Field |
| Vietnam | Block 12W | Premier Oil | 31.875% | Production | 20/11/2030 | 182.26 | |

Notes:
1. The Sampang PSC has the producing Wortel and Oyong gas fields. There are no remaining commitments or relinquishments.
2. The Madura Offshore PSC has the producing Peluang and Maleo gas fields and the undeveloped Meliwis gas field. There are no remaining commitments or relinquishments.
3. Block 12W has the producing Chim Sáo and Dua fields. There are no remaining commitments or relinquishments.
4. Block 12W original PSC effective Nov 2000 was for a 25-year term for oil and a 30-year term for gas. The PSC was amended in 2007 to give a 30-year term without differentiation between oil and gas.

RISC has reviewed the reserves/resources in accordance with the Society of Petroleum Engineers' internationally recognised Petroleum Resources Management System (SPE-PRMS)[1]. RISC was instructed to address only reserves and contingent resources on five fields, and therefore prospective resources are not addressed in this report.

RISC has conducted decline curve analysis on Chim Sáo Field and evaluated future development opportunities and in aggregate supports the Vendor's 2P recovery estimates on Chim Sáo and Dua Fields which are based on reservoir simulation. However, RISC have generated its own 1P, 2P and 3P oil production forecasts that better reflect the 2018 production to date which has been higher than previously forecast.

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

The gross project oil and gas reserves and net attributable to Santos as at 1 January 2018 are summarised in Table 1-2 and Table 1-3.

**Table 1-2: Gross and Net Oil and Condensate Reserves entitlement to PSC's at 1 January 2018**

| PSC | Gross Oil and Condensate Reserves (MMstb) | | | Net Oil and Condensate Reserves (MMstb) | | |
|---|---|---|---|---|---|---|
| | 1P | 2P | 3P | 1P | 2P | 3P |
| Sampang | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Madura | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Block 12W | 22.1 | 33.4 | 45.0 | 7.0 | 10.6 | 14.4 |
| **Total** | **22.1** | **33.4** | **45.0** | **7.1** | **10.7** | **14.4** |

Notes:

1. Gross reserves are on a gross contractor entitlement basis (after government take & economic cut-off) and mid-price case.
2. Net reserves are on a PSC entitlement basis and mid-price case.
3. The Wortel Field in the Sampang PSC produces gas condensate, there are no condensate reserves in the Madura Offshore PSC and Block 12W.
4. The reference point for reserves for the Madura Offshore PSC is the inlet to the East Java Gas Pipeline (EJGP), for Sampang PSC is Santos Onshore Processing Facility (OPF) in Grati and for Block 12W is the FPSO for oil and entry to Nam Con Son pipeline for gas.
5. The volumes have been estimated using deterministic methods and have been added arithmetically.

**Table 1-3: Gross and Net Gas Reserves entitlement to PSC's at 1 January 2018**

| PSC | Gross Sales Gas Reserves (Bcf) | | | Net Sales Gas Reserves (Bcf) | | |
|---|---|---|---|---|---|---|
| | 1P | 2P | 3P | 1P | 2P | 3P |
| Sampang | 21 | 30 | 40 | 9 | 14 | 18 |
| Madura | 11 | 28 | 39 | 7 | 19 | 26 |
| Block 12W | 18 | 28 | 47 | 6 | 9 | 15 |
| **Total** | **50** | **87** | **125** | **22** | **42** | **59** |

Notes:

1. Gross reserves are on a gross contractor entitlement basis (after government take & economic cut-off) and mid-price case.
2. Net reserves are on a PSC entitlement basis and mid-price case.
3. The Chim Sáo and Dua oil fields produce associated gas.
4. The reference point for reserves for the Madura Offshore PSC is the inlet to the East Java Gas Pipeline (EJGP), for Sampang PSC is Santos Onshore Processing Facility (OPF) in Grati and for Block 12W is the FPSO for oil and entry to Nam Con Son pipeline for gas.
5. Sales Gas resources have been adjusted for fuel and flare.
6. The volumes have been estimated using deterministic methods and have been added arithmetically.

The gross project gas contingent volumes and Santos net working interest share as at 1 January 2018 are summarised in Table 1-4, Table 1-5 and Table 1-6.

**Table 1-4: Gross & Net Gas Contingent Volume on Working Interest Basis at 1 January 2018**

| Area | Working Interest | Gross Gas Contingent Volume (Bcf) | Net Gas Contingent Volume (Bcf) |
|---|---|---|---|
| | | 2C | 2C |
| Sampang | 62.5% | 9 | 6 |
| Madura | 62.5% | 44 | 28 |
| Block 12W | 31.9% | 10 | 3 |
| **Total** | | **63** | **37** |

Notes:
1. Net Contingent Volumes are stated on a Working Interest basis. This is not PRMS compliant.
2. Contingent Volumes on a Net Working Interest basis are not entitlement volumes that an entity would have legal and economic entitlement under the relevant PSC terms. Net Contingent Resources can only be defined on an entitlement basis to be compliant with SPE PRMS definitions.
3. Contingent Volumes have not undergone economic limit testing.
4. The Contingent Volumes in the Sampang and Madura Offshore PSC are considered to have the Project Maturity Status of Development Pending.
5. Madura Contingent Volumes include the Meliwis field and Maleo field tail volumes (section 3.4.3)

**Table 1-5: Gross Contingent Volumes (100%) beyond Economic Limit**

| Area | Gross Contingent Volumes beyond Economic Limit | |
|---|---|---|
| | 2C Oil (MMbbl) | 2C Gas (Bcf) |
| Sampang | 0.0 | 0 |
| Madura | 0.0 | <1 |
| Block 12W | 2.5 | <1 |
| **Total** | **2.5** | **<1** |

Notes:
1. Contingent Volumes represent producible volumes which exist after date of economic limit.
2. The volumes have been estimated using deterministic methods and have been added arithmetically.

**Table 1-6: Gross Block 12W Contingent Volumes (100%)**

| Contingent Resources | 2C Oil (MMbbl) |
|---|---|
| Further infill | 4.0 |
| Due Field Blowdown | 1.5 |
| Chim Sáo Field Depressurisation | -1.5 |
| Beyond Economic Limit | 2.5 |
| **Total** | **6.5** |

Gross field volumes before economic cut off and government take are shown in Table 1-7 and Table 1-8.

**Table 1-7: Gross Field Oil & Condensate Volumes and Ophir Net Working Interest Volume at 1 January 2018**

| PSC | Working Interest | Total Gross Field Oil and Condensate Production (MMstb) | | | Economic Gross Field Oil and Condensate Production (before Government Take) (MMstb) | | | Ophir Net Working Interest Oil and Condensate Production (MMstb) | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | P90 | P50 | P10 | P90 | P50 | P10 | P90 | P50 | P10 |
| Sampang | 45.000% | <0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.0 | 0.0 | 0.1 |
| Madura | 67.500% | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Block 12W | 31.875% | 29.4 | 40.3 | 51.3 | 25.0 | 37.8 | 51.3 | 8.0 | 12.1 | 16.4 |
| **Total** | | **29.4** | **40.4** | **51.5** | **25.1** | **37.9** | **51.5** | **8.0** | **12.1** | **16.4** |

1. Reserves can only be defined on an entitlement basis. Total Gross Field Oil and Condensate production, Economic Gross Field Oil and Condensate Production (before Government Take) and Ophir Net Working Interest Oil and Condensate Production cannot be classified as Reserves as this is not compliant with SPE PRMS definitions of 1P, 2P and 3P reserves.
2. Economic limit tested at $60/barrel long term oil price and approx. $5.5/MMBtu gas price.
3. Totals may not add due to rounding of figures in table (i.e.: 51.32 + 0.14 displayed as 51.3 + 0.1 with total of 51.5)

**Table 1-8: Gross Field Gas Volumes and Ophir Net Working Interest Volume at 1 January 2018**

| PSC | Working Interest | Total Gross Field Gas Production (Bcf) | | | Economic Gross Field Gas Production (before Government Take) (Bcf) | | | Ophir Net Working Interest Gas Production (Bcf) | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | P90 | P50 | P10 | P90 | P50 | P10 | P90 | P50 | P10 |
| Sampang | 45.000% | 23 | 34 | 45 | 23 | 34 | 45 | 10 | 15 | 20 |
| Madura | 67.500% | 15 | 35 | 48 | 14 | 35 | 48 | 9 | 24 | 32 |
| Block 12W | 31.875% | 20 | 31 | 51 | 20 | 31 | 51 | 6 | 10 | 16 |
| **Total** | | **58** | **100** | **145** | **57** | **100** | **145** | **26** | **49** | **69** |

Notes:

1. Reserves can only be defined on an entitlement basis. Total Gross Field Gas production, Economic Gross Field Gas Production (before Government Take) and Ophir Net Working Interest Gas Production cannot be classified as Reserves as this is not compliant with SPE PRMS definitions of 1P, 2P and 3P reserves.
2. Economic limit tested at $60/barrel long term oil price and approx. $5.5/MMBtu gas price.
3. Conversion factors used: Madura - 5.437MMscf/boe, Sampang (Wortel field) - 5.954MMscf/boe, Samang – (Oyong field) - 5.899MMscf/boe, Block 12W (Chim Sáo field) - 4.86159 MMscf/boe.
4. Totals may not add due to rounding of figures in table (i.e.: 51.32 + 0.14 displayed as 51.3 + 0.1 with total of 51.5)

The economic model used to calculate Net Present Values (NPV) for the assets under review in this CPR have been audited by RISC and an independent third party and is considered to be fit for purpose by all parties.

RISC has relied on independent legal advice to determine the licence expiry in Block 12W, Vietnam.

A total of five oil price scenarios have been run and three representing the Low, Mid and High cases are shown in Table 1-9 and Table 1-10.

The valuation with an Effective Date of 1 January 2018 (Table 1-9) is the Net Present Value of the forward production and costs from 1 January 2018 with historic costs before 1 January 2018 considered sunk but used in calculations for tax calculations and future tax payments. Valuation of cash flow is the value at 1 January 2018.

A valuation has also been made with a Valuation Date of 1 July 2018 (Table 1-10) to meet the requirements of the UK Listing Authority. This is the Net Present Value of the forward production and costs from 1 January 2018 with historic costs before 1 January 2018 considered sunk but used in calculations for tax calculations and future tax payments. Valuation of cash flow is the value at 1 July 2018.

Asset NPVs for 1P, 2P and 3P reserves are reported at a nominal discount rate of 10%.

The economic values shown in this report have not been adjusted for other factors (e.g. strategic, political and security risks) that a buyer or seller may consider in any transaction concerning these assets and therefore should not be taken to be fair market values.

**Table 1-9: Summary of NPVs for Santos Assets in US Dollars with an Effective Date of 1 January 2018 & Valuation Date of 1 January 2018[1]**

| NPV US$ million | $54/Barrel Long Term | | | $60/Barrel Long Term | | | $70/Barrel Long Term | | |
|---|---|---|---|---|---|---|---|---|---|
| **Asset** | **1P** | **2P** | **3P** | **1P** | **2P** | **3P** | **1P** | **2P** | **3P** |
| Madura | $9 | $19 | $28 | $9 | $19 | $28 | $9 | $19 | $28 |
| Sampang | $11 | $15 | $22 | $11 | $15 | $22 | $11 | $15 | $22 |
| **Indonesia** | **$20** | **$34** | **$50** | **$20** | **$34** | **$50** | **$20** | **$34** | **$50** |
| Chim Sáo | $112 | $148 | $177 | $162 | $202 | $256 | $178 | $225 | $292 |
| **Vietnam** | **$112** | **$148** | **$177** | **$162** | **$202** | **$256** | **$178** | **$225** | **$292** |
| **Total NPV** | **$132** | **$182** | **$226** | **$182** | **$237** | **$306** | **$198** | **$259** | **$342** |

[1]Note: Historic costs before 1 January 2018 are considered sunk (Effective Date) but are used in calculations for tax calculations and future tax payments. The valuation of cash flow is value at 1 January 2018.

**Table 1-10: Summary of NPVs for Santos Assets in US Dollars with Effective Date of 1 January 2018 & Valuation Date of 1 July 2018[2]**

| NPV US$ million | $54/Barrel Long Term | | | $60/Barrel Long Term | | | $70/Barrel Long Term | | |
|---|---|---|---|---|---|---|---|---|---|
| **Asset** | **1P** | **2P** | **3P** | **1P** | **2P** | **3P** | **1P** | **2P** | **3P** |
| Madura | $9 | $19 | $28 | $9 | $19 | $28 | $9 | $19 | $28 |
| Sampang | $11 | $15 | $22 | $11 | $15 | $22 | $11 | $15 | $22 |
| **Indonesia** | **$20** | **$34** | **$50** | **$20** | **$34** | **$50** | **$20** | **$34** | **$50** |
| Chim Sáo | $118 | $155 | $185 | $170 | $212 | $269 | $187 | $236 | $307 |
| **Vietnam** | **$118** | **$155** | **$185** | **$170** | **$212** | **$269** | **$187** | **$236** | **$307** |
| **Total NPV** | **$138** | **$189** | **$235** | **$190** | **$246** | **$318** | **$207** | **$270** | **$356** |

[2]Note: Historic costs before 1 January 2018 are considered sunk (Effective Date) but are used in calculations for tax calculations and future tax payments. The valuation of cash flow is value at 1 July 2018. Cashflows between 1 January 2018 and 30 June 2018 are escalated to Valuation Date of 1 July 2018 at 10%.

All assets were reviewed by RISC in May 2018 and checked in July 2018. No material changes were noted between these dates and the assets performed as predicted by RISC's analysis.

This report is authorised for release by Mr. Gavin Ward, RISC Partner. Mr Ward meets the requirements of ESMA 2013/319 para 133 subsection (a) as a Competent Person.

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## 2. Introduction

### 2.1. Terms of reference

Ophir Energy Plc (Ophir) retained RISC (UK) Limited (RISC) to provide a Competent Persons Report (CPR) on two Indonesia and one Vietnam Production Sharing Contract (PSC), compliant with the requirements of Class 1 transaction under the Listing Rules of the London Stock Exchange for inclusion in a circular/prospectus. This report satisfies the requirements of the European Securities and Markets Authority (ESMA) 2013/319 Appendix III.

### 2.2. Santos's Asian portfolio

Within Asia, Santos holds upstream oil and gas assets in Indonesia, Vietnam, Malaysia and Bangladesh (Figure 2-1). The assets sold to Ophir include the following interests:

- 31.875% in the Block 12W PSC (Chim Sáo and Dua oil fields), Vietnam;
- 67.5% in the Madura Offshore PSC (Maleo and Peluang gas fields), Indonesia;
- 45% in the Sampang PSC (Oyong and Wortel gas fields), Indonesia;
- 20% in the Deepwater Block R PSC (Bestari oil discovery), Malaysia;
- 45% in the SS-11 PSC, Bangladesh;
- 50% in Block 123 PSC and 40% in Block 124 PSC, Vietnam.

Only the producing assets in Indonesia and Vietnam form part of the package that RISC was asked to review. The Indonesian assets comprise interests in the offshore Madura and Sampang PSCs in East Java and the Vietnam asset comprises an interest in Block 12W in the Nan Con Son Basin.


**Figure 2-1: Santos's Asian portfolio**

## 2.3. Basis of assessment

### 2.3.1. Qualifications

RISC is an independent oil and gas advisory firm. All the RISC staff engaged in this assignment are professionally qualified engineers, geoscientists or analysts, each with many years of relevant experience and most have more than twenty years. RISC was founded in 1994 to provide independent advice to companies associated with the oil and gas industry. Today the company has approximately forty highly experienced professional staff at offices in Perth, Brisbane, Jakarta and London. RISC has completed over 2,000 assignments in sixty-eight countries for nearly 500 clients. Our services cover the entire range of the oil and gas business lifecycle and include:

- Oil and gas asset valuations, expert advice to banks for debt or equity finance;
- Exploration/portfolio management;
- Field development studies and operations planning;
- Reserves assessment and certification, peer reviews;
- Gas market advice;
- Independent Expert/Expert Witness;
- Strategy and corporate planning.

The preparation of this report has been managed by Mr. Gavin Ward, RISC Partner. Mr. Ward has a B.Sc. (Hons) Geology & Physics, Aston University UK, an MBA from the Cranfield School of Management UK, is a Chartered Accountant and Fellow of the Association of Chartered Certified Accountants (FCCA). Mr. Ward has 30 years of experience in the sector, is a member of the Society of Petroleum Engineers and is a Council Member of the Petroleum Exploration Society of Great Britain. Mr. Ward is a Competent Person as defined in ESMA 2013/319 para 133 subsection (a) and London Stock Exchange, AIM Guidance Note for Mining, Oil and Gas Companies, March 2009.

### 2.3.2. Limitations

The assessment of petroleum assets is subject to uncertainty because it involves judgments on many variables that cannot be precisely assessed, including reserves/resources, future oil and gas production rates, the costs associated with producing these volumes, access to product markets, product prices and the potential impact of fiscal/regulatory changes.

The Santos assets assessed in this report comprise producing fields and undeveloped hydrocarbon volumes. Additional licenses that form part of the proposed transaction, but which are not included in this report are:

- Block R PSC, Malaysia;
- SS-11 PSC, Bangladesh;
- Block 123 PSC and Block 124 PSC, Vietnam.

RISC has not had access to the seismic data volume over the Chim Sáo field, Vietnam and is basing its observations on material found in reports provided in the Santos Virtual Data room. Although this has limited our review, it has not made a material impact as the reserves valuations are dependent on assessment of production data. However, the lack of access to seismic data has impacted RISC's ability to assess some potential volumes from infill drilling programmes and potential volumes which have not been drilled or where there are no plans by the operator to drill.

The Net Present Value estimates presented in this report have not been adjusted for corporate hedging contracts or other factors (e.g. strategic, political and security risks) that a buyer or seller may consider in any transaction concerning these assets and therefore may not be representative of the fair market value. The statements and opinions attributable to RISC are given in good faith and in the belief that such statements are neither false nor misleading. While every effort has been made to verify data and resolve apparent inconsistencies, neither RISC nor its servants accept any liability for, or warrant the accuracy or reliability of our conclusions, nor do RISC warrant that our enquiries have revealed all the matters, which an extensive examination may disclose.

Whilst this report has been prepared within the context of the effects of petroleum legislation, taxation, and other regulations, that currently apply to assets, RISC has not independently verified property title, encumbrances, regulations that apply to these assets. RISC has not audited the opening balances at the valuation date of past recovered and unrecovered development and exploration costs, undepreciated past development costs and tax losses. However, RISC has studied the PSC terms and has reflected these in the economic valuation.

RISC believe its review and conclusions are sound, but no warranty of accuracy or reliability is given to its conclusions.

Under its contract with RISC, Ophir has agreed to release, discharge and indemnify RISC from all or any claims, losses, costs, expenses, actions, demands, judgments, orders, liability at law or in equity however arising including but not limited to any claim or consequential damages or any other proceedings whatsoever incurred by RISC in respect of any claim by a third party (including associates, agents or employees of the client) in connection with all or any of the services provided by RISC to the client under the terms set out in this document.

### 2.3.3. Independence

RISC makes the following disclosures:

- RISC is independent with respect to Santos and Ophir and confirms that there is no conflict of interest with any party involved in the assignment;
- Under the terms of engagement between RISC and Ophir for the provision of this report, RISC will receive a fee, payable by Ophir. The payment of this fee is not contingent on the intended purpose of this report;
- Neither RISC Directors nor any staff involved in the preparation of this report hold interests in Ophir.

### 2.3.4. Standard

Reserves and resources are reported in accordance with the definitions of reserves, contingent resources and prospective resources and guidelines set out in the Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers in 2007.

### 2.3.5. Definitions

The following paragraphs briefly describe the categories of hydrocarbon volumes listed in this report:

1. **Reserves** (Proved, Probable and Possible): those quantities of petroleum that are anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions;
2. **Contingent Resources** (Low (1C), Best (2C) and High (3C) estimates): 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;
3. **Prospective Resources** (Low, Best and High estimates together with an estimate of the "Geological Chance of Success"): those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.

### 2.3.6. Methodology

The report is compliant with ESMA update of the Committee of European Securities Regulators (CESR); "The consistent implementation of Commission Regulation (EC) No 809/2004 implementing the Prospectus Directive", last updated in March 2013 (ESMA/2013/319) ESMA 2013/319 Appendix III Oil and Gas Competent Person's Report – recommended content"

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

RISC has not conducted a site visit.

Data for the Madura Offshore and Sampang Production Sharing Contract (PSC) were viewed in a Physical Data Room (PDR) in Jakarta during May 2018. Under Indonesia regulations, raw data removal (e.g.: seismic and uninterpreted well logs) was not allowed. As such, RISC's methodology for these PSC's was to verify the range operators in place and estimated ultimate recovery (EUR) estimates and opine on their reasonableness, and where able to do so undertake independent analysis (i.e. material balances) while on location. Details of the findings of our review and the resource estimation process are presented in this report.

Data for Block 12W were made available via a Virtual Data Room during May 2018. This included well by well production data, study reports and JV presentations.

Our assessment for the producing assets is based on production data to end 2017. RISC has reviewed the production history, development plans and costs provided by Santos. RISC has based the net present values presented in this report on gas prices supplied by Ophir and independently verified by RISC staff.

Unless otherwise stated, all resources presented in this report are net entitlement quantities with an effective date of 1 January 2018. All costs are in US Dollars real terms with a reference date of 1 January 2018. Costs are escalated at 2.5%, gas prices are as per in place GSA terms.

# 3. Indonesia – Madura Offshore and Sampang PSCs

The producing offshore gas fields in the Madura Offshore and Sampang PSC's are in late life and significantly depleted with substantial production history from high quality reservoirs. Upside is limited to reducing reservoir abandonment pressure through ultralow compression and minor well intervention activity in the Oyong field. In the case of the Madura Offshore PSC, the yet to be developed Meliwis field could allow extended "tail end" production from the producing Maleo field which is estimated by Santos to approximately 8.3 Bscf in the 2C Case. The recoverable volumes attributed to the Meliwis field and incremental Maleo "tail end" are categorised as Contingent Resources by Santos, dependent on a Meliwis Final Investment Decision (FID).

The potential Meliwis gas development presents the major upside in the PSC's. The Meliwis Plan of Development (POD) was approved by SKK Migas on the 11 January 2018, however FID is not anticipated until mid-2018, as RISC understands that GSA negotiations for Maleo and Meliwis are currently ongoing and expected to be signed by mid-2018. The development consists of a single well drilled from a wellhead platform tied back to the Maleo facilities.

## 3.1. Introduction

### 3.1.1. Asset description

The Madura and Sampang PSC's are located offshore Indonesia in the East Java Basin in water depths of 48 to 65 m with Santos operator of both PSCs. The location of the PSC, fields, relevant working interests and development stage are detailed in Figure 3-1 and Table 3-1.

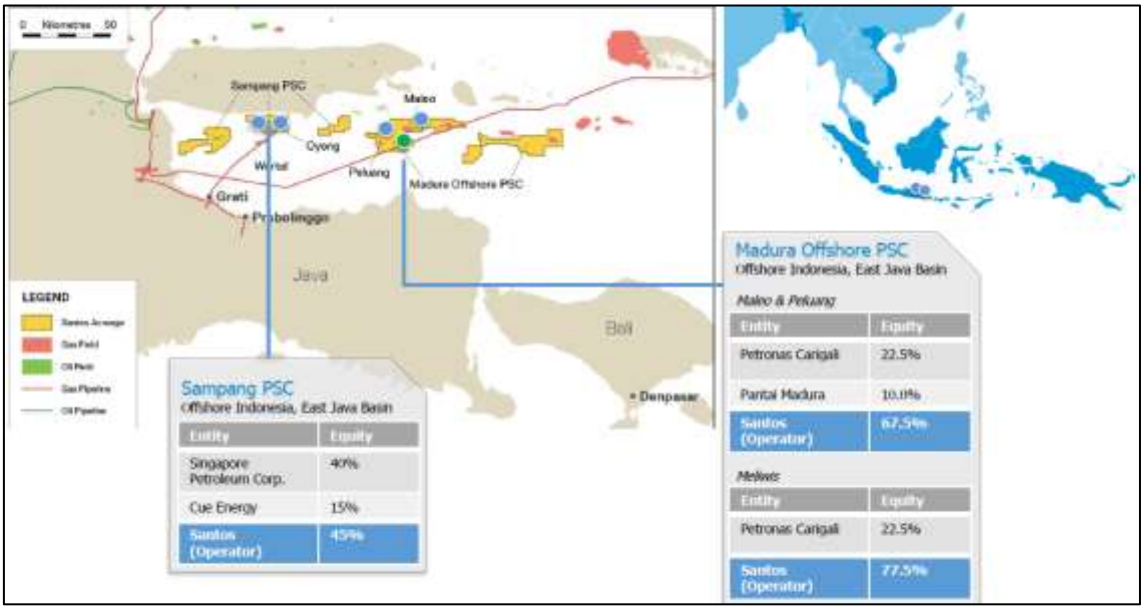


**Figure 3-1: Location of the Sampang and Madura Offshore PSC's with relevant Working Interests**

**Table 3-1: Development stage of the Indonesia assets**

| PSC | Producing Fields (Start-up) | Potential Further Developments | Near Term Exploration Targets |
|---|---|---|---|
| Sampang | Oyong (2012) | Sampang Sustainability Project Phase II | Paus Biru (2018) |
| | Wortel (2012) | | |
| Madura | Madeo (2006) | Meliwis (potential FID mid-2018) | Cangak, Berusaha, Molch (2019-2020) |
| | Pelung (2014) | | |

A site visit was not carried out as nothing was discovered in the Data Room that made a site visit necessary. Santos have demonstrated competence and capability and have a record of performance that RISC is satisfied with.

### 3.1.2. Sampang PSC

The Sampang PSC has gas production from the mature Wortel field with two (2) gas producers and the Oyong field with six (6) wells of which only four (4) wells are currently on production.

The Oyong field is a small (3 x 1 km) elongated, west-east four-way dip structure. The structural relief is about 100 m. The reservoir is shallow at about 1,000 m depth with excellent porosity (40%) and a water saturation of 24%.

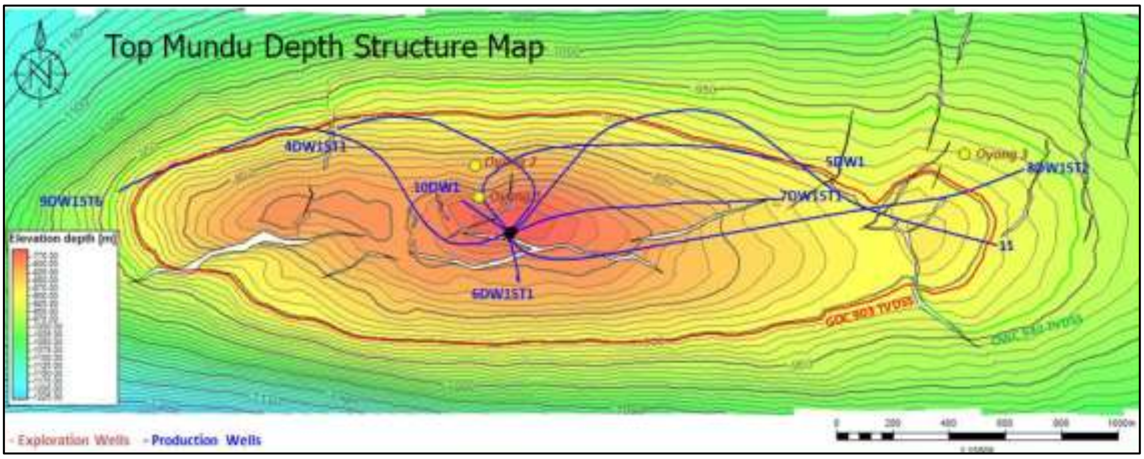


**Figure 3-2 Depth map of the Oyong field**

The Wortel field is the western limit of a plunging east to west nose, with a major north-south fault defining the eastern limit. This results in small (1.5 x 1.5 km) structure. The structural relief is about 100 m. The reservoir is reasonably shallow at about 1,250 m depth with good porosity (31%) and a water saturation of 38%.

The Wortel and Oyong fields are shallow low-pressure reservoirs located at 1,150 mSS and 750 mSS respectively with initial pressures of 2,138 psia and 1,480 psia. Both fields exhibit degrees of aquifer support.

Production commenced from Oyong in 2007 and from Wortel in 2012. Cumulative gross production to year end 2017 (YE2017) is 190 Bcf sales gas and 9.8 MMstb oil and condensate (Oyong: 103 Bcf and 9.7 MMstb; Wortel: 86.8 Bcf and 0.1 MMstb). Gross average 2017 production was approximately 46 MMscf/d sales gas.

Gas from the Wortel WHP is exported to the Oyong WHP which has compression and is transported via 56 km subsea pipeline to a Santos Onshore Processing Facility (OPF) in Grati. After processing, gas is sold to PT Indonesia Power (Grati Power Plant) and the associated condensate sold to PT Pertamina (Persero).

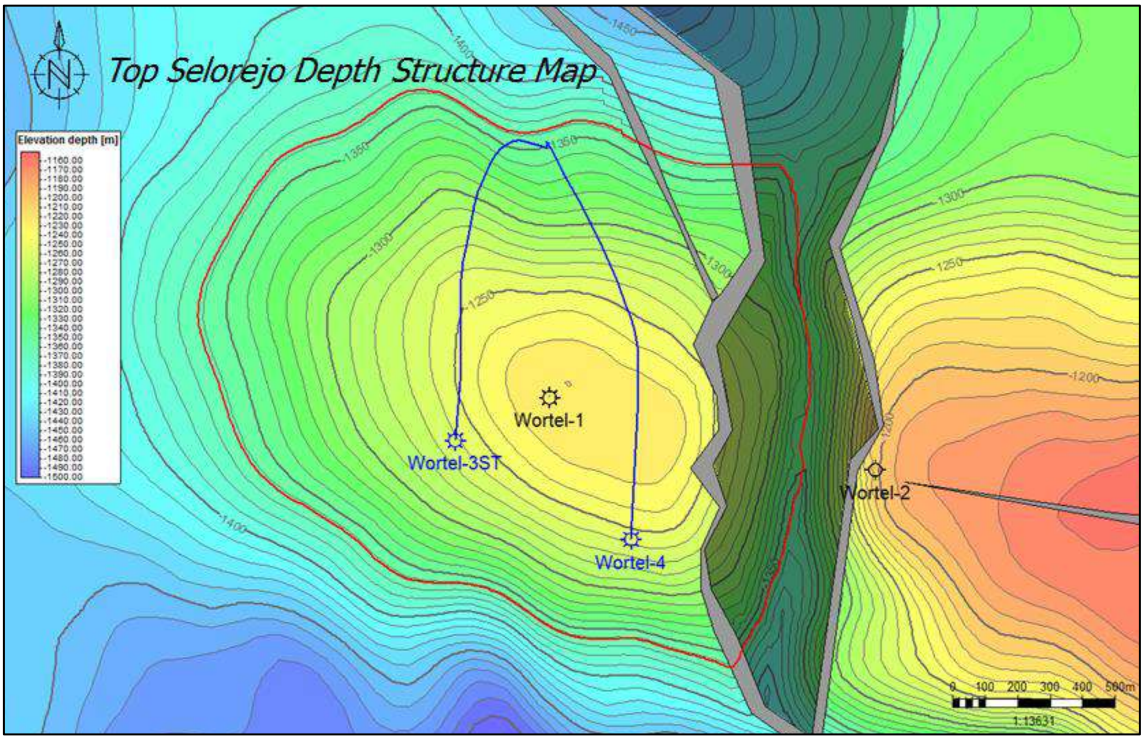


**Figure 3-3 Depth map of the Wortel field**

### 3.1.3. Madura Offshore PSC

The Madura Offshore PSC produces gas from the mature Maleo and Peluang fields with four and one gas producers respectively.

The Peluang field is small (3 x 1 km) west-east four-way dip closed structure. The structural relief is about 60 m and the spill point of the field is a saddle to the northwest. The reservoir is shallow at about 1,000 m depth with excellent porosity (41%) and low water saturation (38%).

The Maleo field is a larger (6 x 3 km) and more pronounced structure with a relief of over 100 m, although the height of the gas column is about 60 m. The reservoir is very shallow (500 m) and reservoir quality is again excellent with porosity of 46% and Sw of 19%.

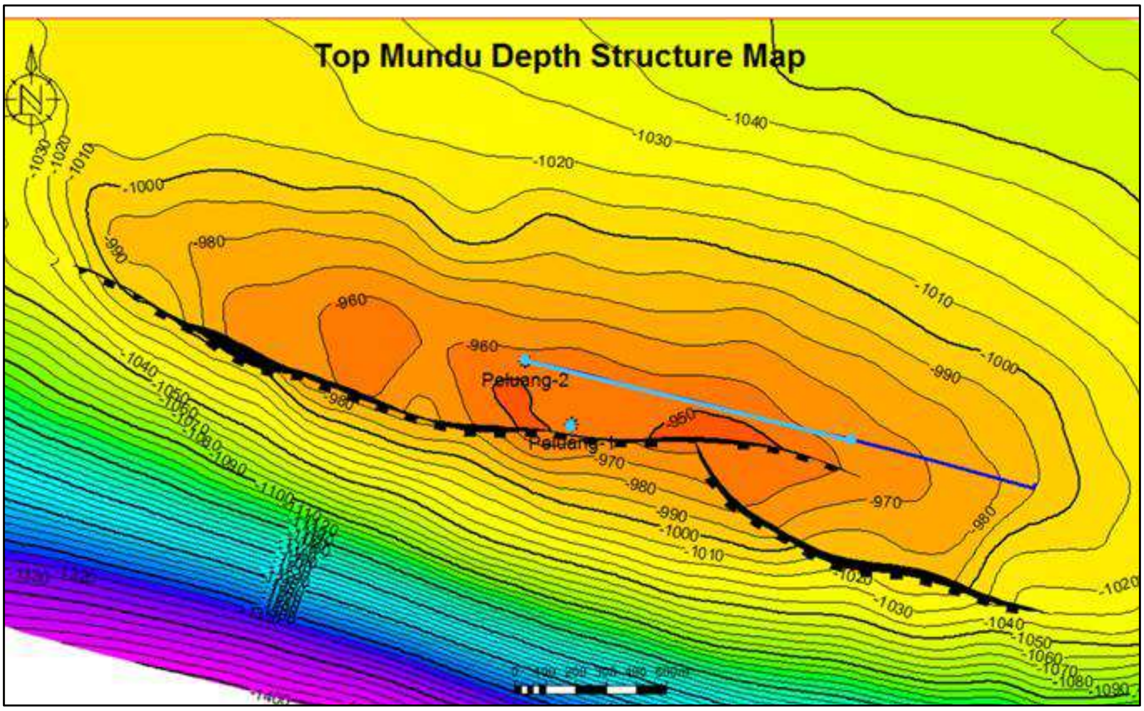

Figure 3-4: Depth map on the Peluang field

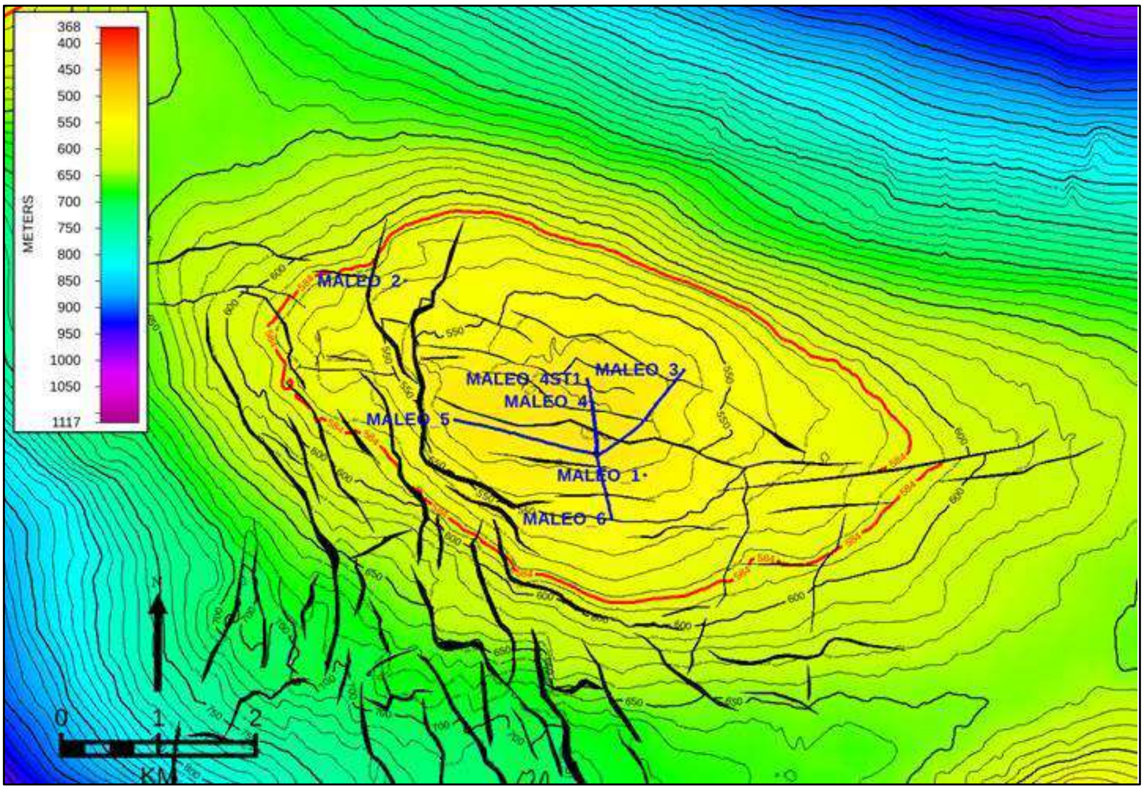

Figure 3-5: Depth map of the Maleo field

Meliwis is a small (2 x 1 km), west-east four-way dip-closured structure (Figure 3-6), probably formed as the result of structural inversion. There is structural relief of about 100 m and the spill point of the field is a saddle to the northwest. There is a major west-east fault within the field which partially offsets the reservoir.

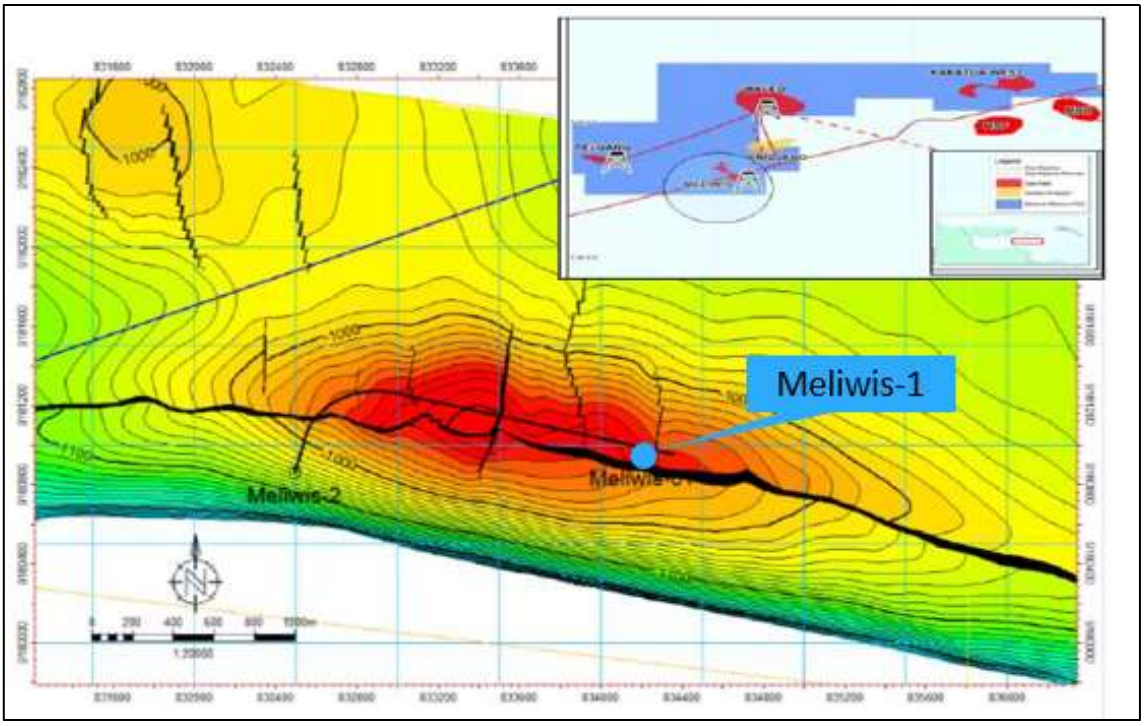


**Figure 3-6: Structure map of the Meliwis field**

The Maleo and Peluang fields are shallow low-pressure reservoirs located at 515 mSS and 940 mSS respectively with initial pressures of 878 psia and 1,480 psia.

Production commenced from Maleo in 2006 and Peluang in 2014. Cumulative gross production (YE2017) is 306 Bcf and 32 Bcf sales gas respectively. Gross average 2017 production was approximately 54 MMscf/d sales gas.

Gas from the Peluang WHP is exported to the Maleo WHP which is tied back to the leased Maleo Production Platform (MPP), which has gas compression. Gas from both fields is processed on the leased Maleo Producer Platform (MPP) before being sold to separate buyers at the inlet to the East Java Gas Pipeline (EJGP).

The Meliwis development is planned as a single well wellhead platform tie-back to Maleo with a plateau rate of 25 MMscf/d. The POD was submitted during Q4 2017 and approved in January 2018. Final Investment Decision is planned for Q3 2018.

### 3.1.4. Regional Geology

The Sampang and Madura Offshore PSCs are located with the East Java Basin (Figure 3-7). Existing infrastructure allows for low cost incremental development opportunities.

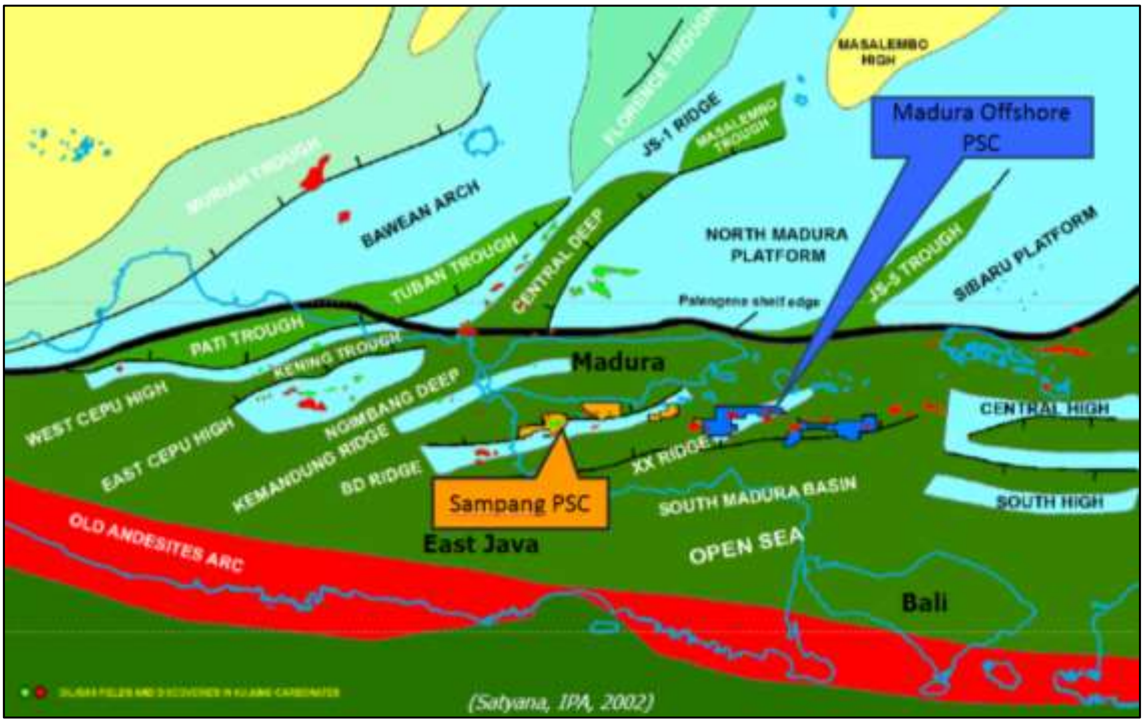


**Figure 3-7: East Java Basin tectonic setting**

There are many plays within the basin and a geological cross section through the Sampang and Madura Offshore PSCs is shown in Figure 3-8. The resources addressed in this report are in the shallow, gas dominated Mundu Formation carbonate play. A stratigraphic column is shown in Figure 3-9.

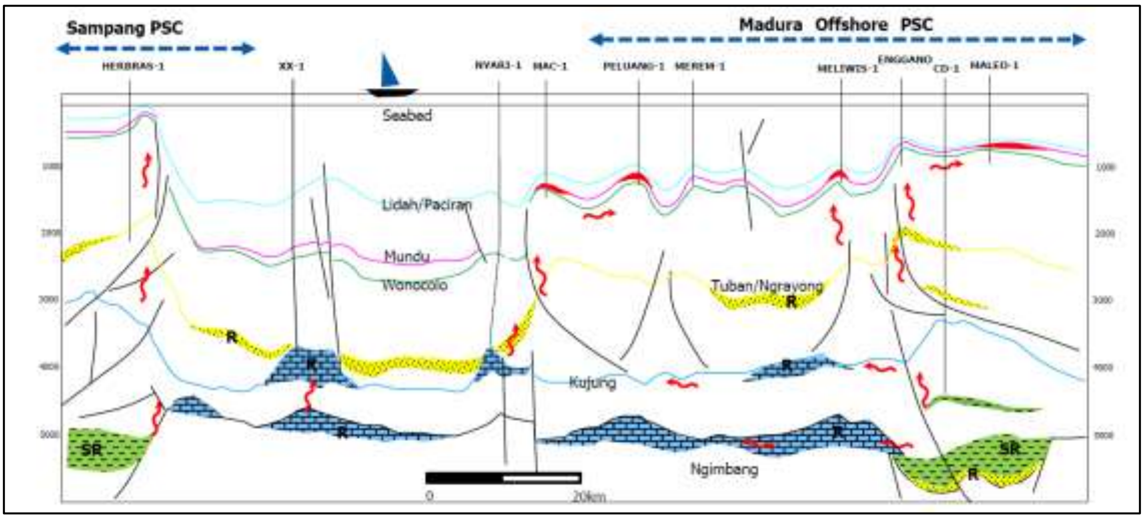


**Figure 3-8: Geological cross section through the Sampang and Madura Offshore PSCs**

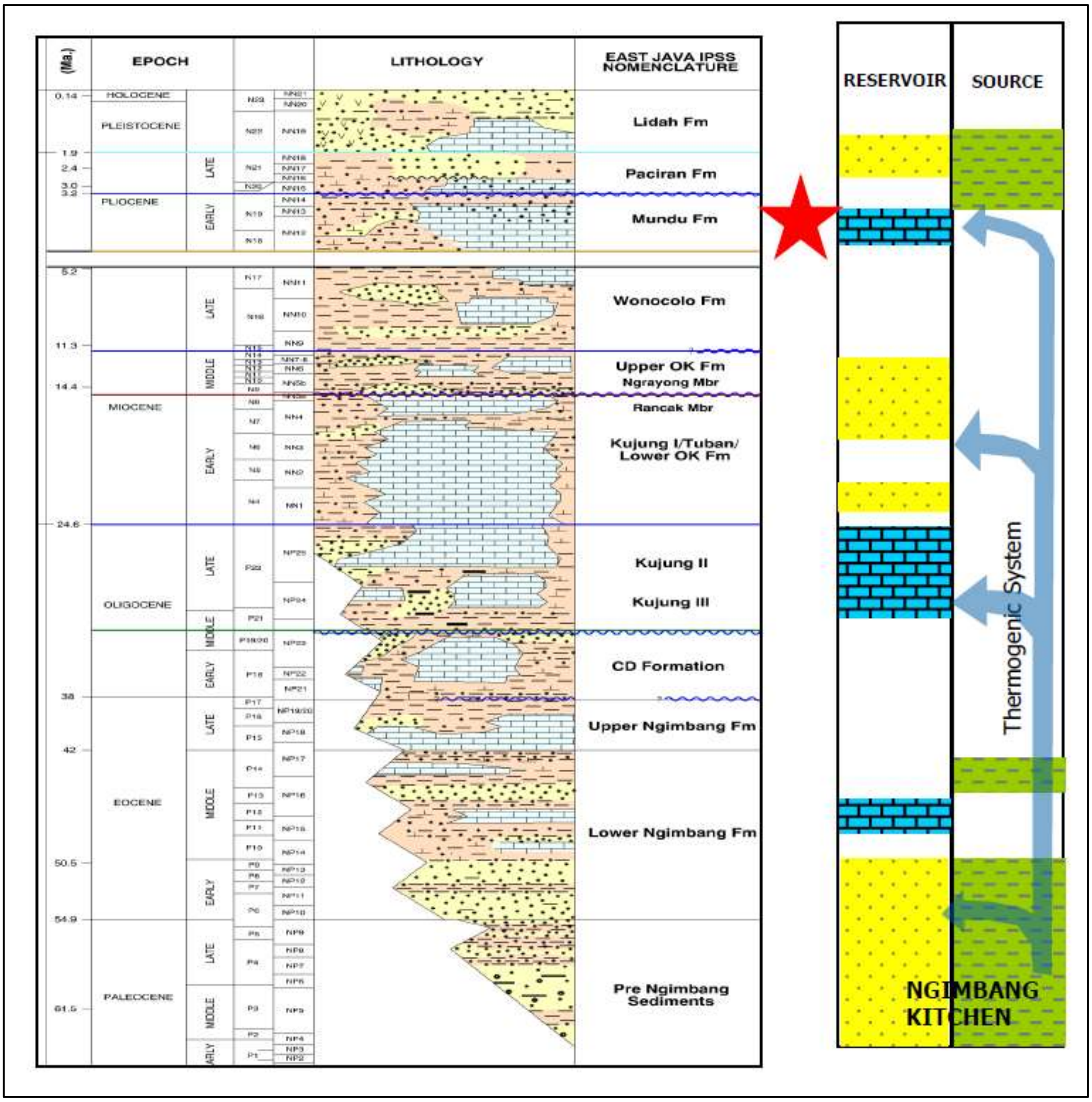


Figure 3-9: East Java Basin stratigraphy

## 3.2. Subsurface Interpretation

### 3.2.1. Volumetrics

This section of the report addresses the Meliwis field, which is currently being considered for development. Performance methods have been used to evaluate the producing fields as described in Section 3.3.

RISC has reviewed Santos interpretations provided in the data room. RISC found that these followed standard industry practices and were generally of high quality.

- The seismic interpretation was carried out using the Paradigm software, well to seismic ties carefully made, the interpretations appear reasonable and multiple depth conversion methods were used to explore depth conversion uncertainty;
- Seismic attributes were used to limited extent. Modelling showed that gas sands can be identified using specific attributes;
- Petrophysical analysis generally carried out using the Geolog Multimin approach (industry standard), correlated to core, RCA and SCAL data where available. Cut-offs generally designed to have no impact on net reservoir giving high net to gross;
- Geological modelling was carried out in Petrel by experienced users following industry standard practices. No cut-offs were applied – consistent with petrophysical analysis and reliance on dynamic modelling to assess recovery from low permeability layers;
- A range of GIIP was modeled using a combination of deterministic and stochastic modelling in Petrel. Top structure uncertainty was assessed, but no variation in reservoir thickness was considered.

The Meliwis field was discovered in 2016 by Meliwis-1, some 100 m down-dip of Maleo field. It is covered by fair to good quality 3D seismic data which was acquired in 2005 and reprocessed in 2011.

Meliwis-1 penetrated a 54 m gas column in the upper Mundu Formation with two (2) DSTs (Drill Stem Test) undertaken with no water or condensate produced. The field has high porosity, but permeability is generally low, averaging 4.5 mD and the field is normally pressured. The pressure data do not indicate hydraulic connection with the Maleo and Pelaung fields. No gas water contact (GWC) was penetrated by the well but RISC has interpreted a GWC at 1,022 mSS.

The Meliwis Plan of Development (POD) was approved by SKK Migas on the 11 January 2018 and assumes a weighted average price (WAP) of $7.53/MMbtu.

The reservoir is the Early Pliocene Upper Mundu Formation and consists of globigerine foraminifer[2] (carbonates) deposited in outer shelf setting, along with glauconite and pyrite minerals. The shallow depth and intra-grain porosity gives high porosities (15 to 53%). However, a high degree of bound water contributes to low permeabilities and high-water saturations. The Lower Mundu Formation is poor quality and not considered in resource estimates.

[2] Marine micro organisms

Santos carry a Free Water Level (FWL) at 1,020 mSS, but there is some uncertainty in this. Meliwis-1 encountered top reservoir at 954 mSS, 45 m down dip of crest of structure at about 910 mSS. DST #2 proved gas down to 985 mSS. DST #1 was inconclusive. The lowest Special Core Analysis (SCAL) data point to indicate gas is at 1,017 mSS. The low permeability Lower Mundu would suggest a long transition zone and the interpretation of Sw and FWL is difficult on the log data. Santos have generated a Sw vs Depth model from mercury injection capillary pressure (MICP) analysis on core data. This model indicates a FWL of 1,020 mSS, which coincides with base case structural spill, acoustic impedance seismic data and the lowest SCAL data point. RISC can support the Santos FWL at 1,020 mSS as base case but consider an uncertainty of at least +/- 5 m appropriate.

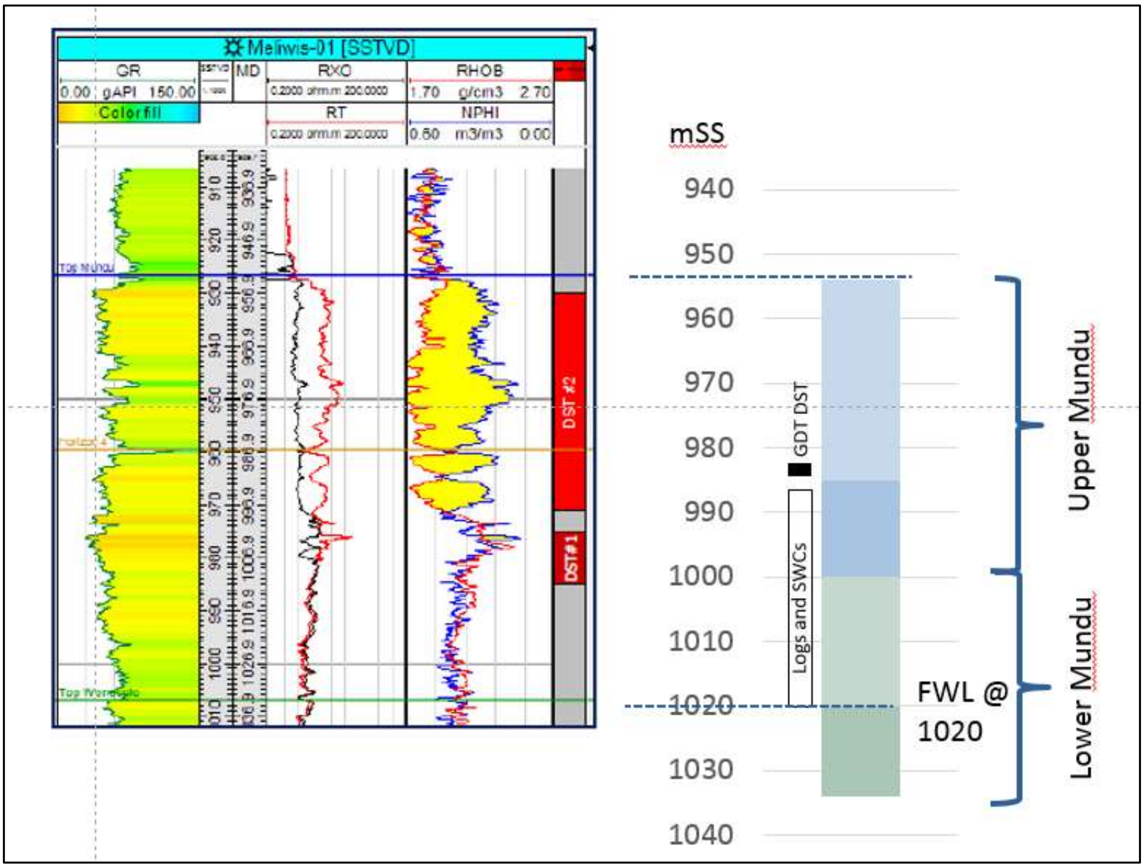


**Figure 3-10: Log data and FWL interpretation of Meliwis-1**

RISC reviewed the Petrel models prepared by Santos, and compared average reservoir properties for porosity, Sw and FVF and found them to be reasonable and consistent with petrophysical sums and averages and fluid properties.

There are several estimates of in-place resources of the Meliwis field, as shown in Table 3-2.

In RISC's view, these estimates do not adequately address uncertainty. Specifically:

- Uncertainty in FWL has not been addressed;
- Although Santos recognised up to 30 m uncertainty in structure at closing contour, greater uncertainty is considered to be necessary;
- No reservoir thickness uncertainty was applied.

Table 3-2: In-place estimates for the Meliwis field

| Source | GIIP (Bcf) | | |
|---|---|---|---|
| | P90 | P50 | P10 |
| **Santos Management Presentation** | 59 | 69 | 81 |
| **FDP deterministic** | 58 | 69 | 80 |
| **FDP Stochastic** | 61 | 69 | 77 |
| **Santos Petrel Model** | 59 | 69 | 82 |
| **RISC** | 50 | 69 | 92 |

RISC therefore independently derived in-place estimates using a 1D probabilistic approach (REP), which yielded a broader range (Table 3-3). The GRV model used ranges of area-depth pairs, thickness and contact. The P50 thickness was input to reproduce the Petrel base case GRV, with a +/- 4 m uncertainty applied. Net to gross is 100%, in-line with the petrophysical analysis and geological modelling. Area-depth pairs were taken from Petrel base case map. Area uncertainty was calculated assuming a +/- 15 m uncertainty to depth map across total structure, which considers depth conversion and mapping uncertainty. Average Porosity and Sw from Santos Petrel modelling realisations was assigned as P50 input. The FVF was taken from Santos Petrel model, with +/- 2% uncertainty. RISC considers the revised P10 to P90 is more appropriate for a field of this maturity and well control.

Table 3-3: RISC 1D probabilistic GIIP estimates of the Meliwis field

| Source | REP Inputs and Results | | |
|---|---|---|---|
| | P90 | P50 | P10 |
| **Thickness (m)** | 53 | 57 | 61 |
| **Area Uncertainty** | 75 | 100 | 125 |
| **GWC (m)** | 1015 | 1020 | 1025 |
| **Porosity (%)** | 41 | 44 | 47 |
| **Net to Gross (%)** | 100 | 100 | 100 |
| **GRV ($km^2m$)** | 90 | 123 | 160 |
| **Sw (%)** | 60 | 63 | 66 |
| **FVF** | 96 | 98 | 100 |
| **GIIP (Bcf)** | **49.8** | **69.0** | **91.6** |

### 3.2.2. Fluid properties

The Meliwis reservoir fluid is a dry gas with minimal inert gases. Laboratory derived PVT (Pressure, Volume and Temperature) properties are as shown below in Table 3-4. RISC noted traces of $H_2S$ were detected in DST testing, however were not present in lab samples. RISC confirmed the lab derived expansion factor is consistent with correlations.

**Table 3-4: Meliwis Reservoir Fluid Properties**

| Property | Unit | Gas Column |
|---|---|---|
| Pressure | psig | 1661 |
| Temperature | deg C | 70.5 |
| Expansion factor 1/Bg | scf/cf | 99 |
| Specific Gravity | - | 0.596 |
| Inserts ($CO_2$ and $N_2$) | % mol | 2.05 |
| C5+ | % mol | 0.9 |

### 3.2.3. Well testing

DST well testing was undertaken with $H_2S$ detected in DST 1. Both DST's indicated limited deliverability with flow rates of 3.9 and 13 MMscf/d. Derivative plots from both DSTs indicated the presence of nearby boundaries, interpreted to be either the primary East West normal fault or the secondary North-South faulting. RISC reviewed the well test interpretation and considers DST 2 reasonable. DST 1 is more problematic noting the low net to gross of approximately 0.112 and the apparent skin of 110 the well test interpretation is questionable. As the zone that DST 1 tested is not included in volumetrics nor considered productive DST 1 and its anomalies are not relevant to the Meliwis development.

**Table 3-5: Meliwis DST Results**

| DST | Zone | Gross interval (m) | Gas rate (MMscf/d) | Kh (mD.m) | S | Remarks |
|---|---|---|---|---|---|---|
| DST 1 | A | 10 | 3.9 | 103 | 110 | Pressure transient response indicates significant skin of 110 with boundary observed approx. 30 m, estimated radius of investigation ~ 337 m. $H_2S$ recorded @ 35 ppm. Effective permeability approx. 10.3 mD. Zone not included in Meliwis development. |
| DST 2 | B | 41 | 13 | 205 | 2.5 | Lower permeability compared to upper zone DST with boundary observed approx. 14 m. No $CO_2$ or $H_2S$ evident. Effective permeability approx. 5 mD. |

### 3.2.4. Development Concept

The Meliwis development plan envisages an unmanned Well Head Platform (WHP) in 74 m of water tied back to the Maleo Production Platform (MPP). The development strategy is very similar to successful Peluang development, with the same standalone screen completion design.

A single 4 ½" 1,200 m crestal horizontal well is planned on the northern part of the field, targeting the upper Mundu Formation since 80% of the field gas is in this segment of the field (Figure 3-11). The rational of locating the well parallel to the north side of the main fault is to connect any compartments caused by the north-south striking faults and RISC considers this prudent.

Within the proximal area, faults are not generally hydraulically sealing and RISC notes that fault throw is < 10 m and reservoir is juxtaposed against reservoir. Simulation sensitivities suggest that if the fault is sealing, then the southern compartment is not connected, and recovery will be lower by approximately 7 Bscf.

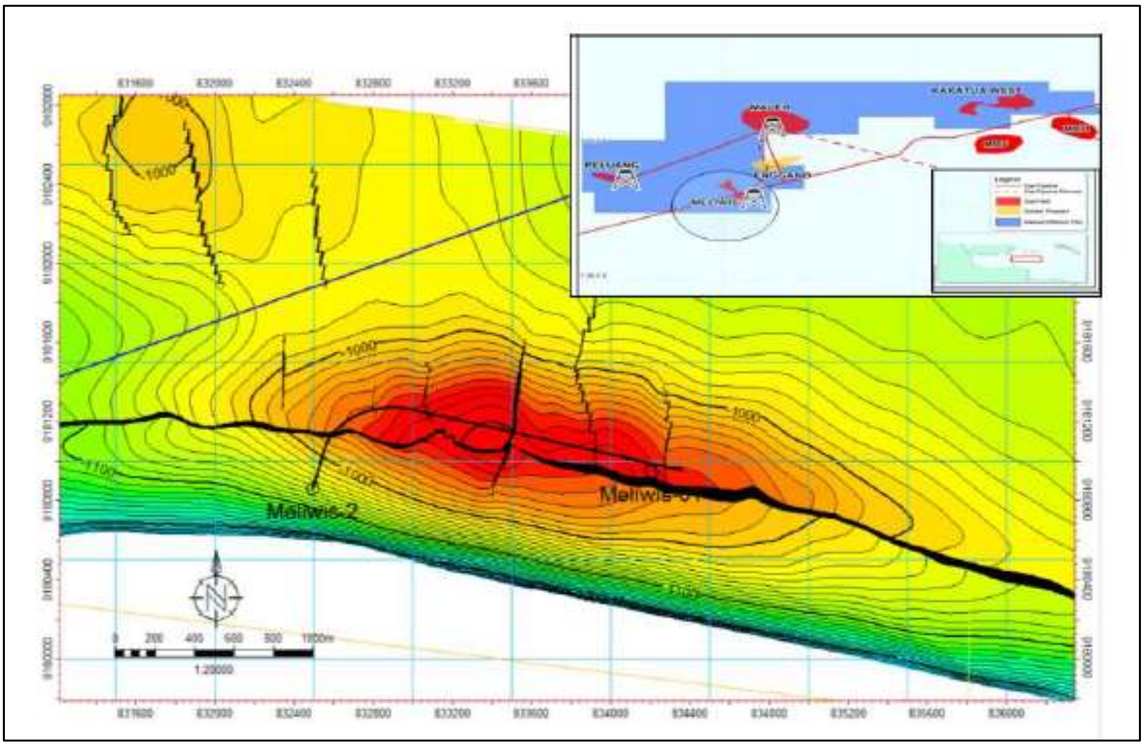


**Figure 3-11: Proposed Location of Meliwis - 2 Development Well**

### 3.2.5. Reservoir Modelling

Santos has undertaken multiple realization reservoir modelling to capture structural and petrophysical uncertainties. Three cases were selected by Santos for assigning 1C, 2C and 3C resources, resulting in gas recovery of 19, 34 and, 45 Bscf respectively. This represents a range of recovery factors (RF) of between 35 to 53%. This range of Recovery Factors need to be seen in the context of the relatively high reservoir abandonment pressures due to production constraints of 250 psi FTHP and a slightly lowered 12 MMscf/d compression inlet rate at the MPP and the expectation that the area to the south of the main east-west fault will be drained.

The modelled runs indicate that porosity, residual gas saturations (Sgr) in the upper Mundu, structure and aquifer properties are the most significant parameters on recovery. RISC reviewed the range of SCAL derived relative permeability curves and noted the very low relative permeability for water (Krw) at residual gas saturations, inferring retarded aquifer encroachment into the reservoir.

RISC interrogated Santos's P50 simulation model and noted that the aquifer influx is constrained at the edges by low permeability zones. As reservoir properties in the lower Mundu are poorer, bottom drive aquifer influx is not anticipated. A Carter Tracey edge water aquifer is modelled with a HCPV/Aq pore volume ratio of approximately 4, suggesting limited water drive is anticipated. The initial plateau rate is assumed to be 25 MMscf/d. Pre- and post-simulation saturation profiles indicate the proposed horizontal well does not water out during the production period with the P50 model suggesting a reservoir abandonment pressure of 730 psia.

RISC independently estimated the 2C RF and noted in the unconstrained production P50 case less than 2 Bscf of gas was trapped by aquifer encroachment and this supports the simulation modelling that suggests that aquifer influx is constrained due to low permeability.

Santos undertook offtake sensitives at 20 MMscf/d, as per the SKK POD approved offtake rate, and this indicated no significant impact on gas recovery.

RISC considers the simulation modelling robust and adequately captures the range of uncertainty.

Independent certification of the Contingent Resource has been undertaken by Lemigas in October 2017, and RISC notes their 2C gas Contingent Resource estimate is approximately 37 Bscf, however the documentation does not explain how this figure was derived.

## 3.3. Historical Production Analysis

The Madura Offshore PSC fields, Maleo and Peluang produce dry gas with minimal inert gases (< 1%). The Maleo field is in decline whilst the Peluang field is on plateau and provides backfill to Maleo. Both fields have a degree of weak aquifer support and there has been no evidence of aquifer water production to date consistent with the crestal location of the production wells.

In the Sampang PSC, the Oyong field was originally produced as an oil field depleting the oil rim. Oil production ceased mid 2017 with minor condensate production continuing into 2018 and the gas cap is now being blown down. The adjacent Wortel field is in decline and produces gas with minor condensate (CGR approximately 5.5 bbl/MMscf). Both fields are interpreted to have a degree of aquifer support. With cessation of oil production, condensate from Wortel is now spiked back into the gas export line.

The fields have high deliverability and the wells are completed with sand control due to the unconsolidated nature of the reservoir. Maleo wells are completed with 5 ½" wire wrapped screens with 7" production tubing and Peluang wells have same lower completion with 4 ½" production tubing. Oyong wells are completed with 4 ½" wire wrapped screens and 4 ½" production tubing whilst Wortel wells have 5 ½" wire wrapped screens and 4 ½" production tubing. To date there has been no evidence of excessive sand production in any of the fields that would suggest failures of the lower completions.

RISC notes regular well tests in the fields over the 2016 to 2017 period have not indicated deterioration in well performance with skin factor generally interpreted below 5 except for Peleuang-2 where recent 2016 and 2017 well testing indicates a significant skin of greater than twenty. Santos has suggested investigating the benefits of acidizing the well to increase well deliverability and potentially recovery, however RISC is not aware of ongoing studies or plans.

Historical production for the fields is shown in Figure 3-12 and Figure 3-13 below.

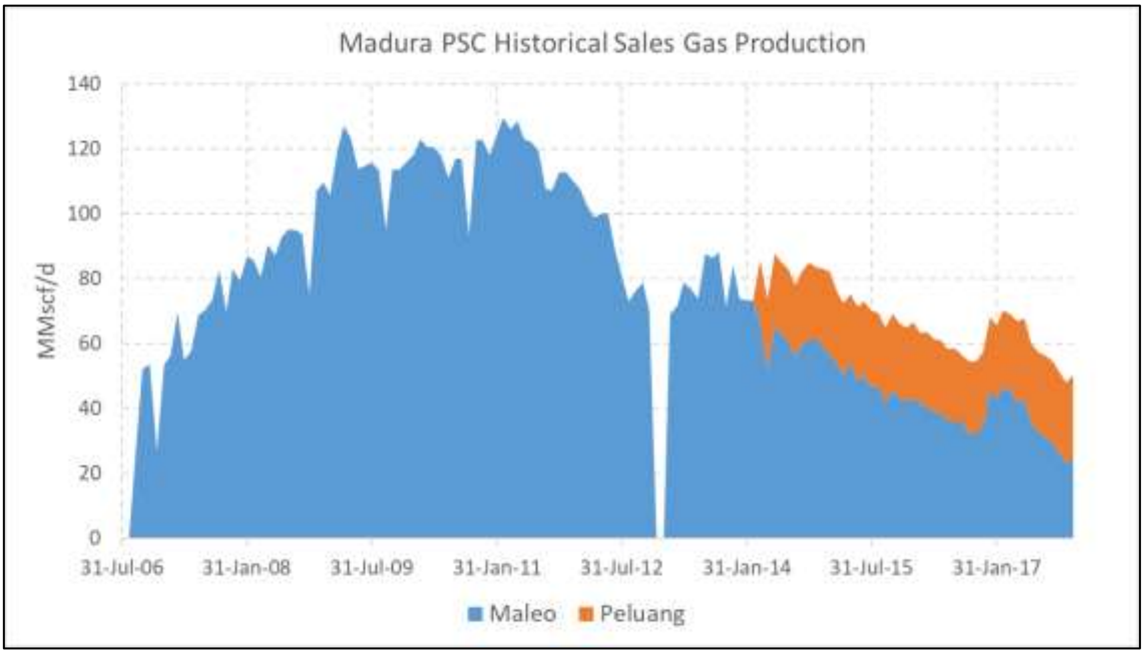


**Figure 3-12: Madura Offshore PSC Historical Sales Gas Production**

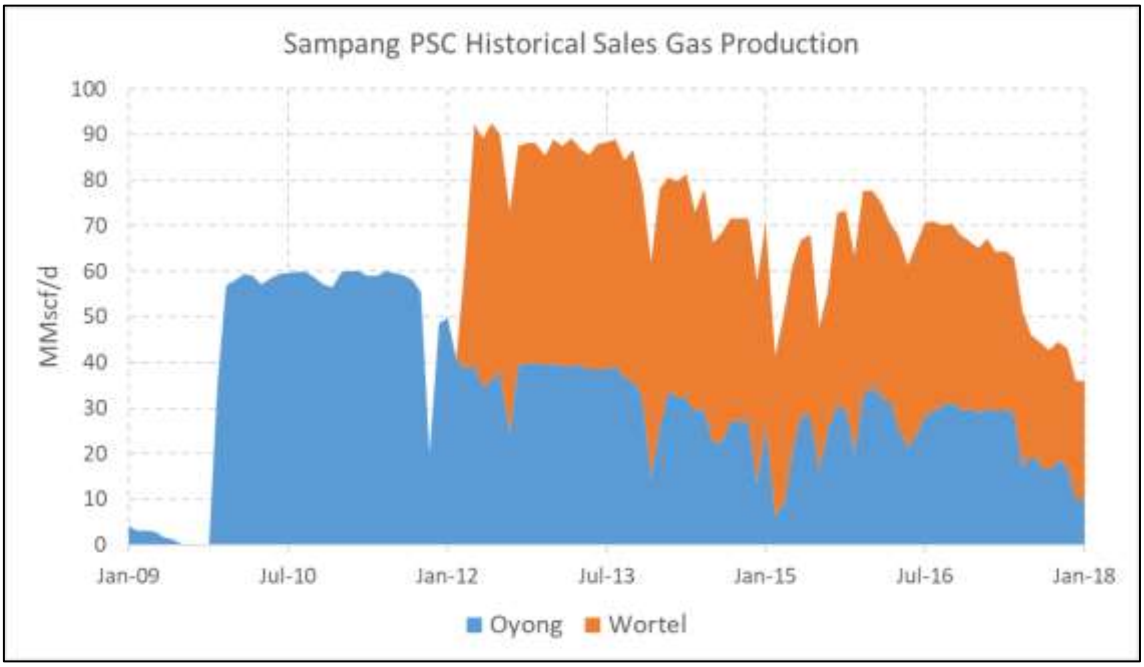


**Figure 3-13: Sampang PSC Historical Sales Gas Production**

RISC has conducted its own material balance analysis on each field. In general, RISC's work supports the Santos material balance derived estimates of GIIP. The four producing fields are all interpreted to exhibit some degree of aquifer support.

Wortel: Santos presents a high case for the Wortel field based on p/Z modelling and Flowing Material balance analysis, both assuming volumetric depletion drive resulting in a high side case of approximately 160 Bscf. RISC does not support this interpretation.

Maleo: The Havlena Odeh and Cole plots suggests a best case GIIP of approximately 383 Bscf as shown in the left Figure 3-14 and this is contrasted with the 3P GIIP of 423 Bscf as per below which indicates a poorer match as shown in the right of Figure 3-14.

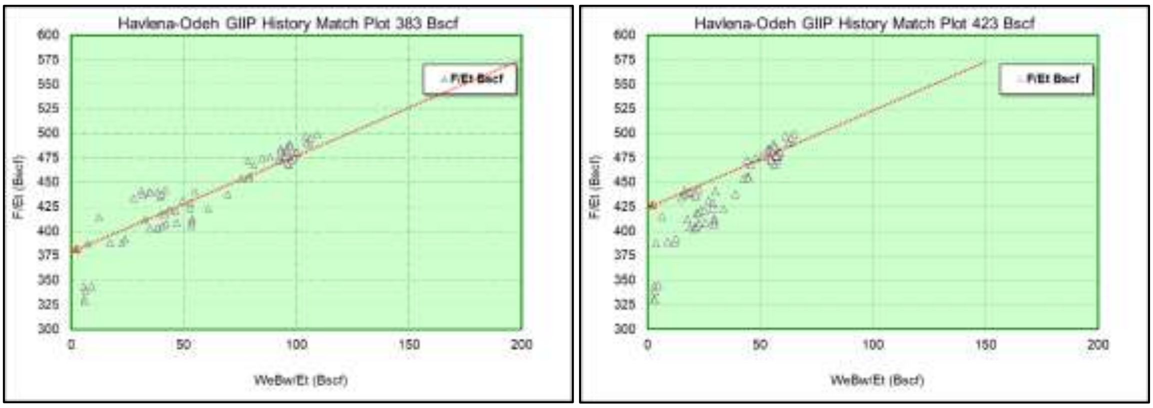


**Figure 3-14: Maleo field Havlena Odeh Plots for 383 and 423 Bscf Respectively**

## 3.4. Resources and Production Forecasts

### 3.4.1. Producing Fields

Santos' resource estimates and production forecasts have been derived from history matched Eclipse simulation models. Multi realizations of over 400 runs (using EnABLE software) has been used to derive a range of forecasts with specific cases selected from the output S-curve distribution to represent 1P, 2P and 3P. RISC has reviewed the EnABLE multi realization methodology and considers it reasonable with the selected 1P, 2P and 3P case GIIPs commensurate with RISC's material balance derived range of GIIP.

RISC has reviewed the quality of the 1P, 2P and 3P pressure history matches on a well by well basis (flowing tubing head) and average reservoir pressure and considers them reasonable apart from Oyong. RISC notes that the Oyong field 2P and 3P history matches are generally better than the 1P matches and have displayed better water production matches than the 1P case. RISC opines the selected 1P case model may be overly conservative.

RISC notes the Peluang and Wortel 1P cases water out due to pronounced aquifer influx, whereas all other fields the 1P, 2P and 3P cases cease flow due to declining reservoir pressure. Maleo 2P and 3P cases appear to liquid load at very late life due to declining well rates. RISC considers uncertainty in drive mechanisms has been adequately captured as well as liquid loading.

RISC has independently verified the 2P simulation model's recovery factors volumetric sweep efficiencies based on initial and abandonment pressures, Swc and Sgr.

In the Madura Offshore PSC, the Maleo MPP gas export compression has a minimum suction flowrate of 15 MMscf/d with a current inlet pressure of 120 psig. Whilst the FTHP of the Maleo field is less than the Peluang field the compressor inlet pressure prevents Peluang backing out Maleo production. Rewheeling will occur in Q4 2019 and will reduce inlet pressure to 50 psi with the AFE approved by both SKK Migas and the JV. FID is anticipated to occur in late July 2018 in conjunction with Meliwis FID and noting incremental capex is minimal and a reasonable expectation exists that FID occur, RISC considers the associated incremental production to be reserves and has included this in its forecasts.

In the Sampang PSC the Wortel field produces to the Oyong WHP. Whilst the Wortel field has a higher FTHP than the Oyong field, this offset somewhat by the 17 km distance from the Oyong WHP and back out effects are not seen with preferential production of Wortel. The Wortel field produces condensate and there is no evidence of declining CGR and as such condensate forecast assumes constant CGR and RISC considers this reasonable. With cessation of oil production from the Oyong field, condensate production from Wortel field is spiked back into the gas export line. Given the low condensate production rate and regular pigging of the gas export pipe line excessive liquid hold up is not anticipated to occur.

Current gas production from the Oyong WHP free flows to the Santos Onshore Processing Facility (OPF) in Grati with landing pressure ranging from 250 to 90 psi with a minimum gas flow to customers of 10 MMscf/d. As discussed in the Contingent Resources section, the proposed SSP Phase-2 will involve reduction in the Grati onshore receiving terminal to 10 psi.

RISC notes that 2018 production in fields such as Maleo has been significantly above the 2018 budget production forecast. RISC has reviewed Santos' revised 2018 field forecasts and modified Santos' simulation forecasts to match actual 2018 production to date. This was achieved by scaling field sales gas rates based on field gas potential. RISC's scaling did not alter volumes produced prior to reaching production constraints. RISC's sales gas production profiles are shown in Figure 3-15 and Figure 3-16.

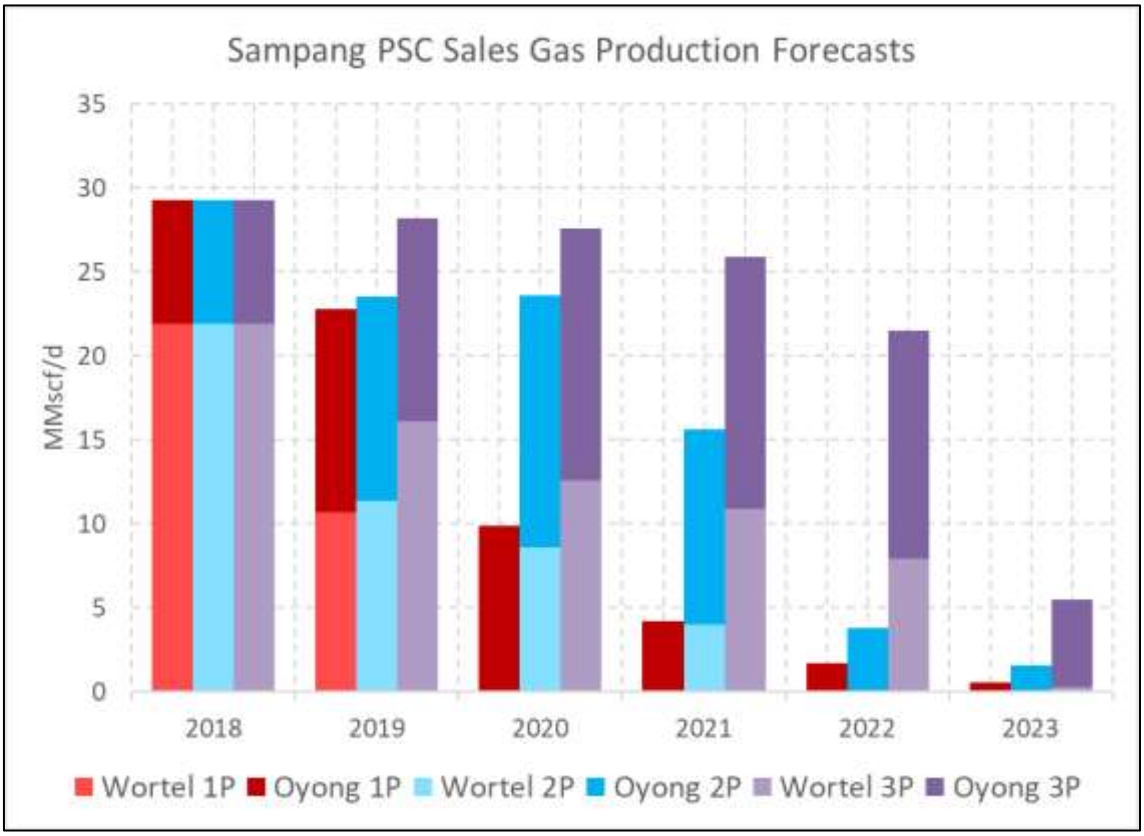


**Figure 3-15: Sampang PSC Sales Gas Production Forecasts**

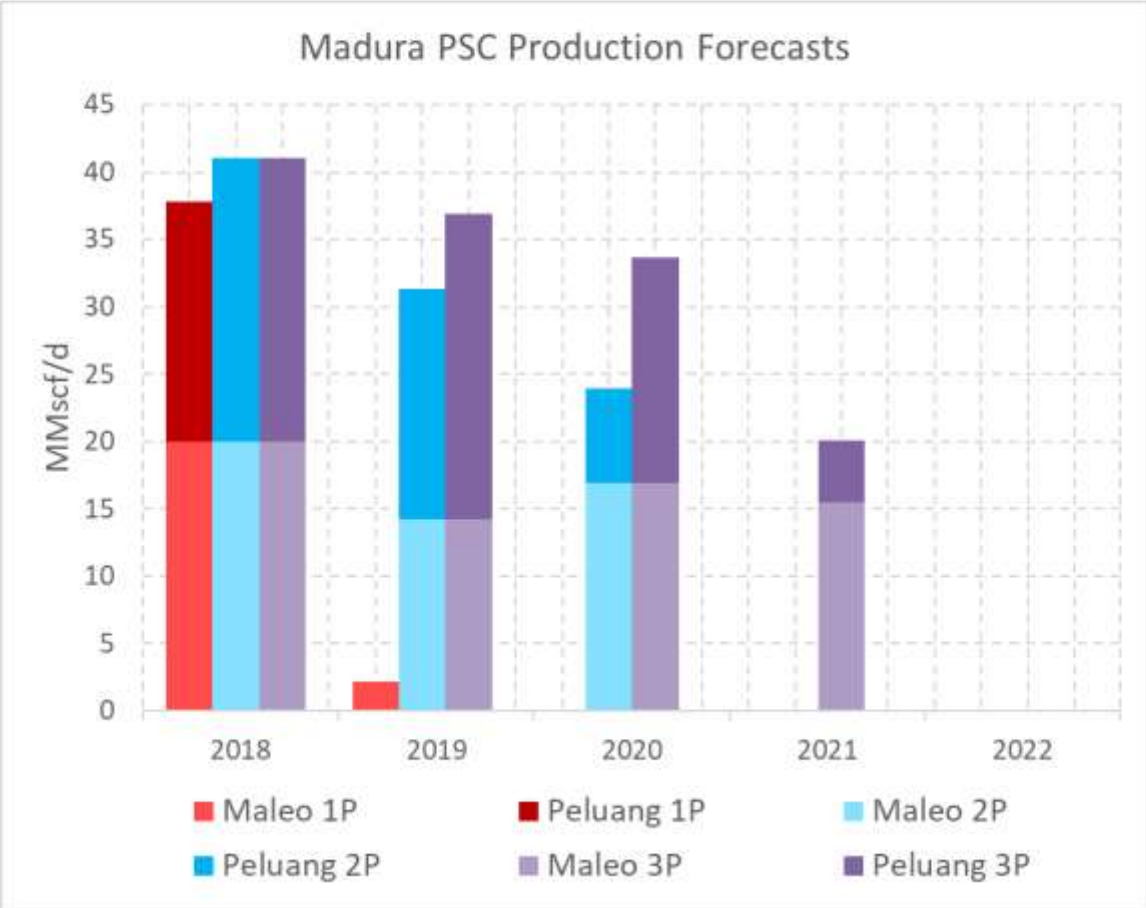


**Figure 3-16: Madura Offshore PSC Sales Gas Production Forecasts**

### 3.4.2. Resource Summary

RISC reviewed the estimates of gas consumed in operations (i.e.: fuel, flare and losses) by comparing total gas rates against sales gas rates and notes the estimates of gas consumed in operations in the simulation models are in line with historical gas consumed in operations at PSC levels.

**Table 3-6: Sampang PSC Gross reserves as at 1 January 2018**

| Gas and Condensate | Unit | Gross Reserves | | |
|---|---|---|---|---|
| | | 1P | 2P | 3P |
| Wortel Field Sales Gas | Bscf | 10.6 | 15.1 | 19.2 |
| Wortel Field Condensate | MMstb | 0.0 | 0.0 | 0.0 |
| Oyong Field Sales Gas | Bscf | 10.0 | 15.0 | 20.6 |
| **Total Sales Gas** | **Bscf** | **20.6** | **30.1** | **39.8** |
| **Total Condensate** | **MMstb** | **0.0** | **0.0** | **0.0** |

Notes:

1. Gross reserves are on 100% contractor entitlement basis and mid-price case.
2. Sales Gas resources have been adjusted for shrinkage and fuel gas.
3. The notional reference point for gas is the Santos Onshore Processing Facility (OPF) in Grati.
4. Deterministic evaluation methods have been used.
5. Additions beyond the field level have all been made arithmetically.

**Table 3-7: Sampang PSC Net reserves as at 1 January 2018**

| Gas and Condensate | Unit | Net Reserves | | |
|---|---|---|---|---|
| | | 1P | 2P | 3P |
| Wortel Field Sales Gas | Bscf | 4.8 | 6.8 | 8.6 |
| Wortel Field Condensate | MMstb | 0.0 | 0.0 | 0.0 |
| Oyong Field Sales Gas | Bscf | 4.5 | 6.8 | 9.3 |
| **Total Sales Gas** | **Bscf** | **9.3** | **13.6** | **17.9** |
| **Total Condensate** | **MMstb** | **0.0** | **0.0** | **0.0** |

Notes:

1. Sales Gas resources have been adjusted for shrinkage and fuel gas.
2. Net reserves are on a PSC entitlement basis and mid-price case.
3. The notional reference point for gas is the Santos Onshore Processing Facility (OPF) in Grati.
4. Deterministic evaluation methods have been used.
5. Additions beyond the field level have all been made arithmetically.

Table 3-8: Madura Offshore PSC Gross reserves as at 1 January 2018

| Gas | Unit | Gross Reserves | | |
|---|---|---|---|---|
| | | 1P | 2P | 3P |
| Peluang + Maleo Fields Sales Gas | Bscf | 10.9 | 28.3 | 38.5 |
| **Total Sales Gas** | **Bscf** | **10.9** | **28.3** | **38.5** |

Notes:

1. Sales Gas resources have been adjusted for shrinkage and fuel gas.
2. Gross reserves are on 100% contractor entitlement basis and mid-price case.
3. The notional reference point for gas is at the inlet to the East Java Gas Pipeline (EJGP).
4. Deterministic evaluation methods have been used.
5. Additions beyond the field level have all been made arithmetically.

Table 3-9 Madura Offshore PSC Net reserves as at 1 January 2018

| Gas | Unit | Net Reserves | | |
|---|---|---|---|---|
| | | 1P | 2P | 3P |
| Peluang + Maleo Fields Sales Gas | Bscf | 7.4 | 19.1 | 26.0 |
| **Total Sales Gas** | **Bscf** | **7.4** | **19.1** | **26.0** |

Notes:

1. Sales Gas resources have been adjusted for shrinkage and fuel gas.
2. Net reserves are on a PSC entitlement basis and mid-price case.
3. The notional reference point for gas is at the inlet to the East Java Gas Pipeline (EJGP).
4. Deterministic evaluation methods have been used.
5. Additions beyond the field level have all been made arithmetically.

### 3.4.3. Contingent Resources

Santos has identified several further development opportunities which are currently classified as Contingent Resources.

#### *3.4.3.1. Oyong Sustainability Project Phase 2*

Gas from the Oyong WHP free flows to the Grati onshore receiving terminal which limits the FTHP of Oyong field to approximately 250 psig. Santos has modified existing 1P, 2P and 3P simulation models and lowered the FTHP to 125 psig and reduced the inlet pressure at Grati onshore receiving terminal to 10 psig. This analysis indicates an additional 8.5 Bscf on incremental 2C production is achievable. Santos have classified this volume as a Contingent Resource under the Oyong Sustainability Project (SSP) Phase 2 and RISC supports this. Pre-FEED is currently ongoing with respect to the technical feasibility.

### 3.4.3.2. *Maleo Tail Volume*

With Meliwis anticipated to be online in Q2 2019, noting the minimum compression inlet rate of 12 MMscf/d it allows Maleo tail volumes to be produced down to a final Maleo field rate of approximately 6.5 MMscf/d. Whilst the initial Meliwis FTHP of approximately 1,200 psig is far higher than the MPP compression suction inlet pressure of 120 psig, Meliwis' initial production bypasses MPP compression to prevent backing out of Maleo production until Meliwis FTHP has declined. Santos has modified extended 1P, 2P and 3P simulation models to allow the Maleo field to produce to a minimum rate of 6.5 MMscf/d and this analysis indicates an additional 8.3 Bscf on incremental 2C production. Santos have classified this tail volume as Contingent Resources and RISC supports this.

### 3.4.3.3. *Upper Mundu perforation Oyong Field*

The estimated Contingent Resources are not material being less than 0.2 Bscf.

### 3.4.4. Meliwis Production Forecasts

Contingent Resource volumes are those carried by Santos, audited and adjusted by RISC where necessary. RISC has scaled the Santos 1C and 3C cases to reflect its view of the P90 and P10 GIIP. RISC's Meliwis Contingent Resource estimates and production forecasts as shown in Figure 3-17.

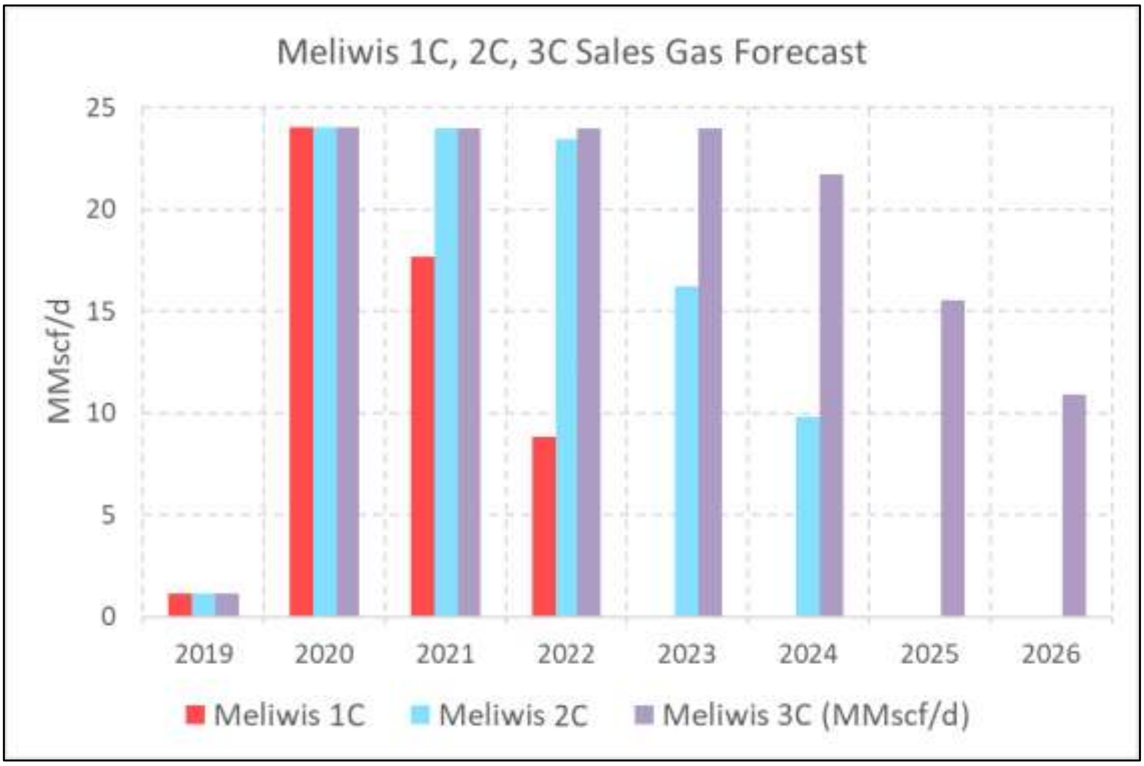


**Figure 3-17: RISC Meliwis 1C, 2C and 2C Sales Gas Forecasts**

**Table 3-10: Meliwis Gross Sales Gas Production**

| Year | 1C Annual Production (Bscf) | 2C Annual Production (Bscf) | 3C Annual Production (Bscf) |
|---|---|---|---|
| **2019** | 0.40 | 0.40 | 0.40 |
| **2020** | 8.75 | 8.75 | 8.75 |
| **2021** | 6.46 | 8.75 | 8.75 |
| **2022** | 3.21 | 8.56 | 8.75 |
| **2023** | - | 5.91 | 8.75 |
| **2024** | - | 3.58 | 7.93 |
| **2025** | - | - | 5.67 |
| **Total Sales Gas (Bscf)** | **18.82** | **35.95** | **49.00** |

Notes:

1. Contingent Resources are stated on Gross 100% contractor entitlement basis and have not undergone economic limit testing.
2. Sales Gas resources have been adjusted for shrinkage and fuel gas.
3. The notional reference point for gas is at the inlet to the East Java Gas Pipeline (EJGP).
4. Deterministic evaluation methods have been used.

## 3.5. Future Expenditure

### 3.5.1. Sampang PSC

The Wortel and Oyong fields are fully developed. Phase 2 of the Sampang Sustainability Project (SSP2) is a potential further capital project. This involves capital expenditure of approximately $10 million to lower the suction pressure at the Grati Onshore Compressor. However, this project has not been approved and therefore RISC do not include the project in our reserves valuation cases. No other capital expenditures are envisaged (exploration related expenditure is outside the scope of this report).

Operating expenditure is budgeted to be $22 million in 2018. RISC estimate it will remain at around this level in 2019 before reducing slightly to approximately $20 million/year at end of economic life.

Santos advise all abandonment liabilities to have been met, therefore no further provision for abandonment is required.

### 3.5.2. Madura PSC

The Maleo and Peluang fields are fully developed. The only anticipated capital expenditure is approximately $2 million to restage the Maleo compressor. FID for this project is anticipated in July 2018.

Capital costs for a Meliwis development are estimated to be approximately $70 million for a single well drilled from a WHP tie-back to Maleo. FID is expected in Q3 2018 with start-up late 2019.

Operating expenditure is budgeted to be $33 million in 2018. RISC estimate this will increase to $36 million/year when Meliwis comes online before reducing slightly to approximately $30 million/year at end of economic life.

Santos advise all abandonment liabilities to have been met, therefore no further provision for abandonment is required other than approximately $10 million for Meliwis well P&A and facility decommissioning.

# 4. Vietnam - Block 12W

## 4.1. Introduction

### 4.1.1. Asset description

Block 12W is located offshore Vietnam in the Nan Con Son Basin in a water depth of approximately 95 m (312 ft.) with Premier Oil operator of the PSC. The location of the PSC, fields and relevant working interests are detailed in Figure 4-1.

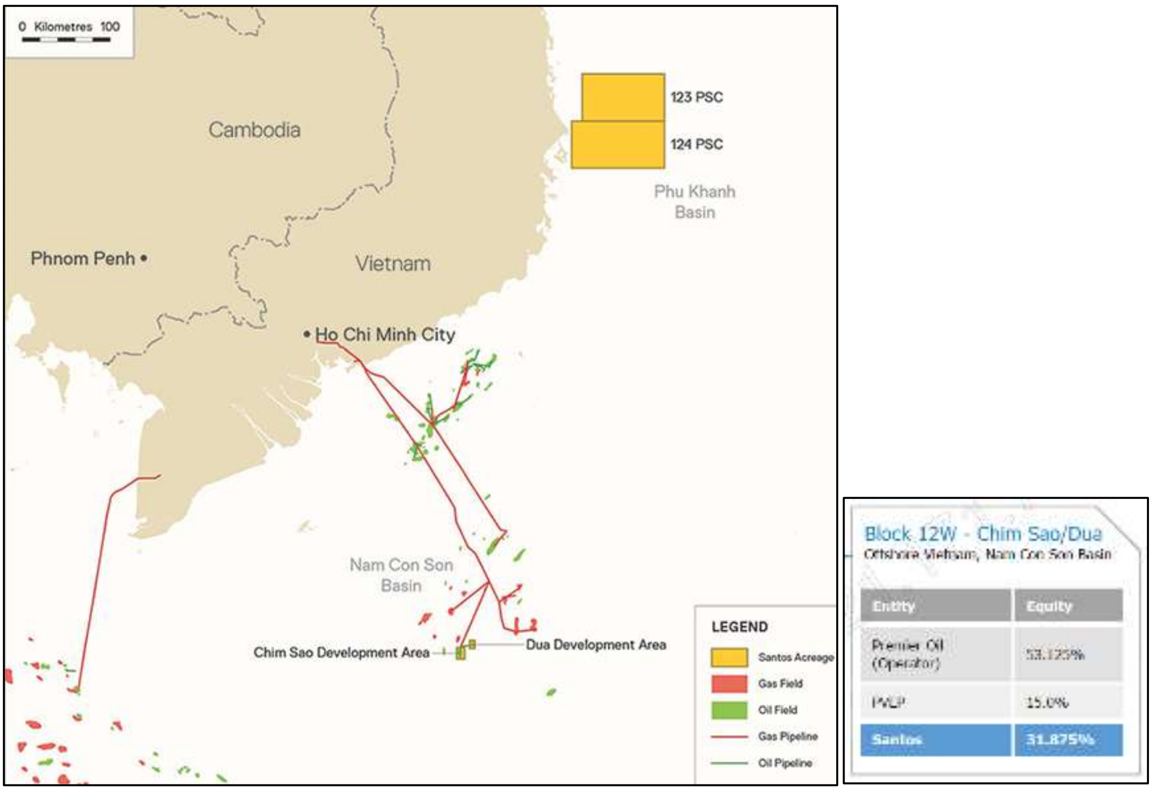


**Figure 4-1: Location of the 12W PSC, Vietnam**

Block 12W contains the producing Chim Sáo and Dua oil and gas fields. Dua is approximately 20 km from Chim Sáo. Chim Sáo field is a three-way, dip closure trending north-south, with fault closure to the west. It was discovered by wells 12E-CS-1X and 12E-CS-1XST1 and contains oil and gas bearing reservoirs in fluvio-deltaic to shallow marine 'Middle Dua' sands of Miocene age. The main reservoirs are MDS1, MDS5 and MDS6 sands.

The Dua field was discovered in 1974 by Pecten with Dua-1X well. The Dua-2x appraisal well drilled in 1975 was a dry hole. Well 12-A-1X drilled to the south of the structure was also dry. In 2006, Premier drilled Dua-4x, -4xST1, -4xST2 and 5x-RE wells to further delineate the field. Dua Field is split into north and south fault blocks separated by a major east-west trending fault. A three-way dip closure forms the down dip limit of the field to the north, west and south.

Dua contains oil and gas bearing reservoirs in the fluvio-deltaic to shallow marine 'Middle Dua' sands of Miocene age. Main reservoirs are MDS1 & MDS2 in Dua North and MDS3 in Dua South. In 2014, Dua-01, Dua-02 and Dua-03 began producing via subsea tie-back to Chim Sáo, peaking at 9,000 bopd.

Both fields produce through the leased Lewek EMAS FPSO. Chim Sáo produces through thirteen (13) producers to a Well Head Platform with Dua producing through three (3) subsea tiebacks approximately 17 km from the FPSO. The Chim Sáo field is under water injection with seven (7) injectors with the instantaneous voidage compensation (IVC) exceeding 100% since 2014.

Gas is exported to the Dinh Co Terminal via a 96 km pipeline that connects to the Nam Con Son pipeline. Gas is sold to PetroVietnam for domestic power generation.

The Chim Sáo field commenced oil production in 2011 with the Dua field subsea tieback online in 2014. Cumulative gross production to year end 2017 (YE17) was 54.8 MMstb (Chim Sáo: 51.6 MMstb, Dua: 3.1 MMstb) with sales gas of 32.8 Bscf. Gross average 2017 production was approximately 27,000 stb/d oil and 25 MMscf/d of associated gas.

A site visit was not carried out as nothing was discovered in the Data Room that made a site visit necessary. Premier Oil have demonstrated competence and capability and have a record of performance that RISC is satisfied with.

### 4.1.2. Regional Geology

The Nam Con Son Basin formed in the Upper Oligocene in response to the opening of the South China Sea, Figure 4-2. The syn-rift Upper Oligocene Cau Formation is the principal source rock in the basin. Post-rift clastics dominated by tidal delta complexes were deposited from the Upper Oligocene through to the Late Miocene. The post-rift clastic section includes the primary reservoirs within the Chim Sáo and Dua fields are the Middle Dua Sands (MDS) of Lower Miocene age and the Upper Dua Sands (UDS) of Middle Miocene age. The structural closures of Chim Sáo and Dua were formed during inversion and transpressional movement within the Middle Miocene. A chronostratigraphic chart for the Nam Con Son Basin highlighting the MDS and UDS sands is presented in Figure 4-3.

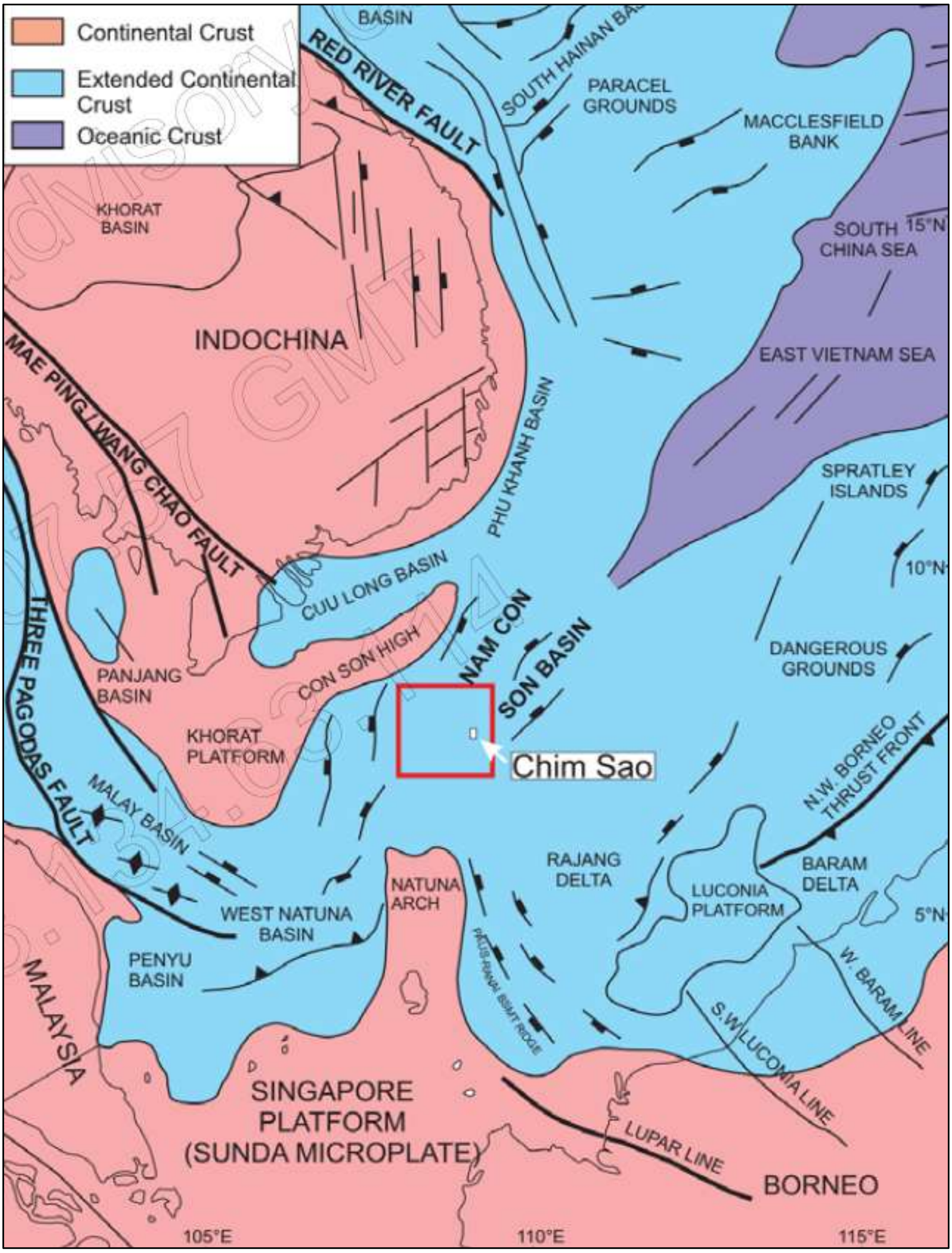


**Figure 4-2: Location of the Nam Con Son Basin (Oolithica 2016)**

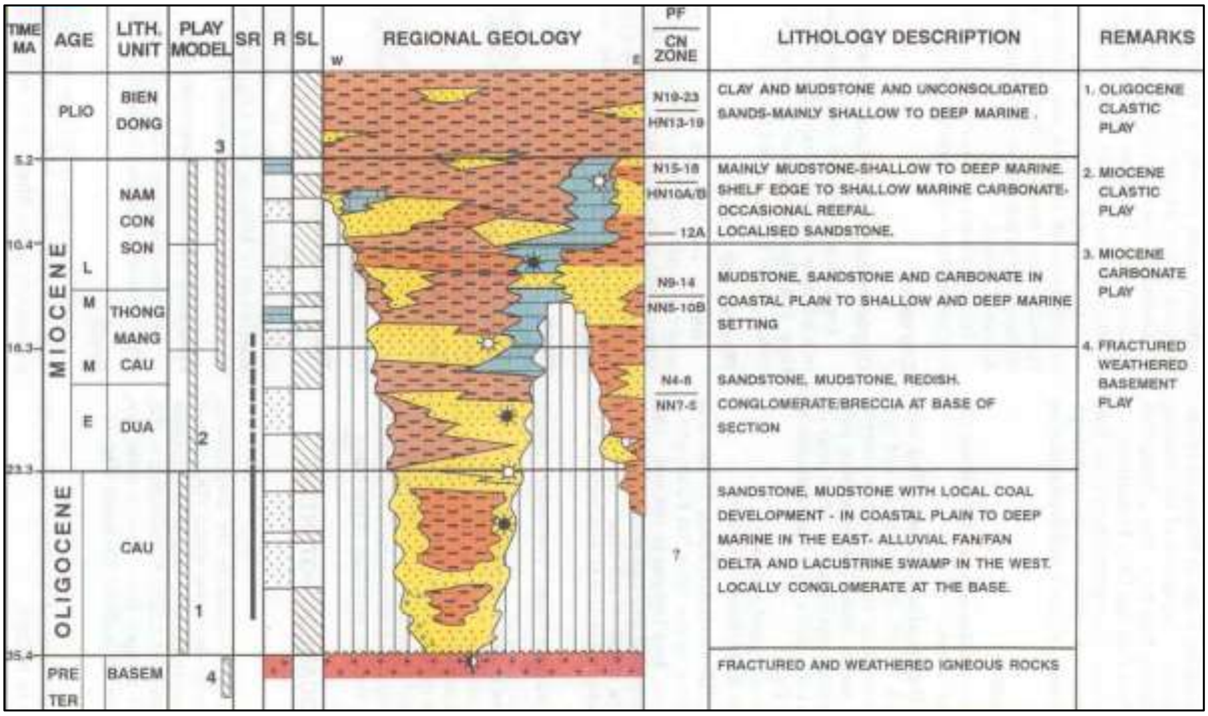


**Figure 4-3: Chronostratigraphic chart of the Nam Con Son Basin (after Tin & Ty[3])**

[3]Nguyen Trong Tin & Nguyen Dinh Ty, Petroleum geology of the Nam Con Son Basin, Vietnam Petroleum Institute, 1994

## 4.2. Subsurface interpretation

Three separate accumulations exist in Block 12W. Chim Sáo is the main producing field. Chim Sáo is a north-south trending three -way dip closure with fault closure to the west. The reservoirs accessed are the MDS1, MDS5 and MDS6. Chim Sáo NW is a developed fault block northwest of Chim Sáo field. The reservoirs accessed are the Intra Mang Cau (IMC) 12, UDS1, UDS2 and UDS3. The Dua field is 17 km northeast of the Chim Sáo field. The reservoirs accessed are the MDS1, MDS2, MDS3 and MDS6.

### 4.2.1. Seismic interpretation

The Dua 3D seismic survey was acquired in 2005. The Chim Sáo 3D seismic survey was acquired in 2007. The seismic interpretation has been validated throughout the drilling campaigns across the fields.

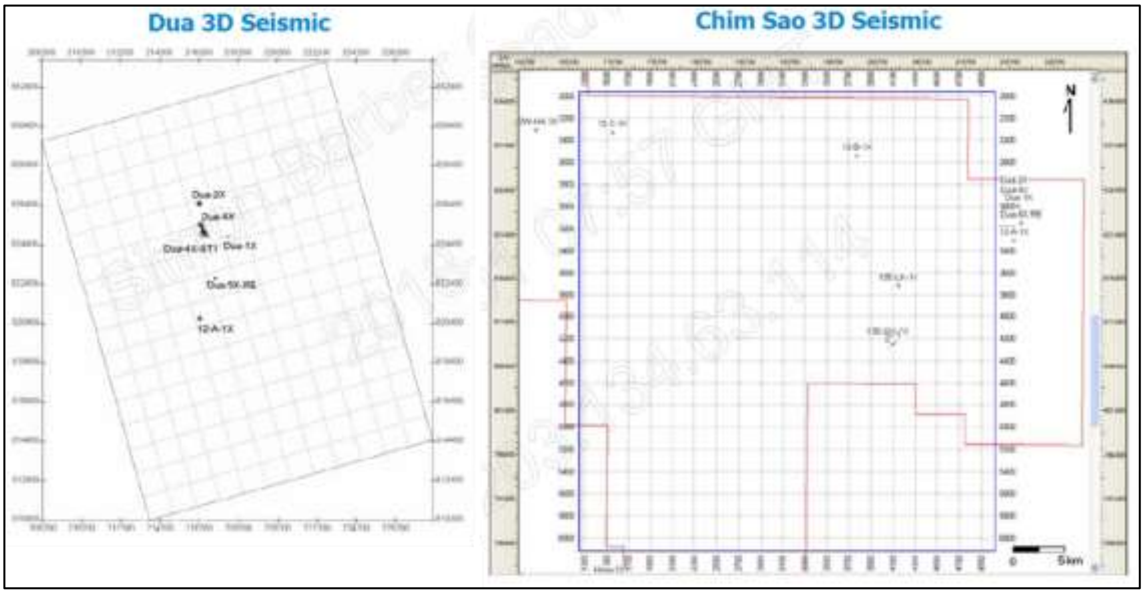


**Figure 4-4: Dua and Chim Sáo 3D Seismic Areas**

The quality of the 3D seismic data has been sufficient for amplitude work by Santos to characterise the higher quality reservoirs developed across the Chim Sáo Field such as the recognition of channel trends being developed in the MD5 reservoir.

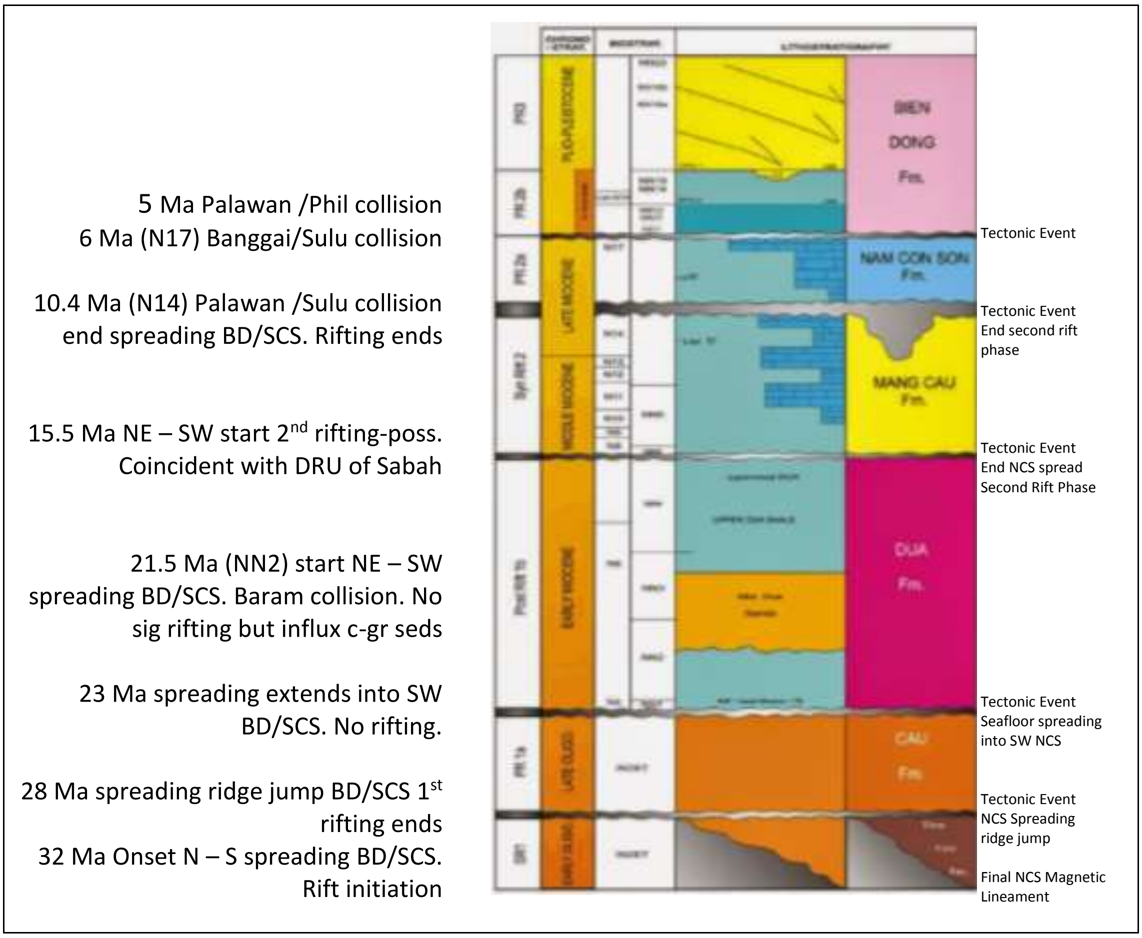


**Figure 4-5: Stratigraphy (after Swiecicki & Maynard[4])**

RISC has not had access to the seismic data volume over the Chim Sáo field and is basing its observations on material found in reports provided in the Santos Virtual Data room. Although this has limited our review, it has not made a material impact, as our review of the reserves estimates used production performance methods. However, the lack of access to seismic data has impacted RISC's ability to assess some potential volumes from infill drilling programmes and potential volumes which have not been drilled or where there are no plans by the operator to drill.

### 4.2.2. Reservoir description

The depositional environment of the MDS reservoirs is interpreted to be a fluvio-tidal delta system. The MDS reservoirs are widespread and can be mapped across the three fields. The earlier MDS units are characterised by low accommodation space-controlled deposition leading to sand rich intervals migrating seaward over relatively long distances. Later MDS units are more shaley and heterogeneous.

[4]Seismic Atlas of SE Asian Basins: Nam Con Son (http://geoseismic-seasia.blogspot.com/2014/04/nam-con-son.html)

The depositional models for major producing reservoirs of MDS and MD6 were based on integration of core and cuttings studies, together with FMI, log correlation, seismic-stratigraphic analysis and RMS seismic amplitude maps. The main sand input axis is interpreted to have been oriented broadly west-east and located in the south of the Chim Sáo field, Figure 4-6 and Figure 4-7.

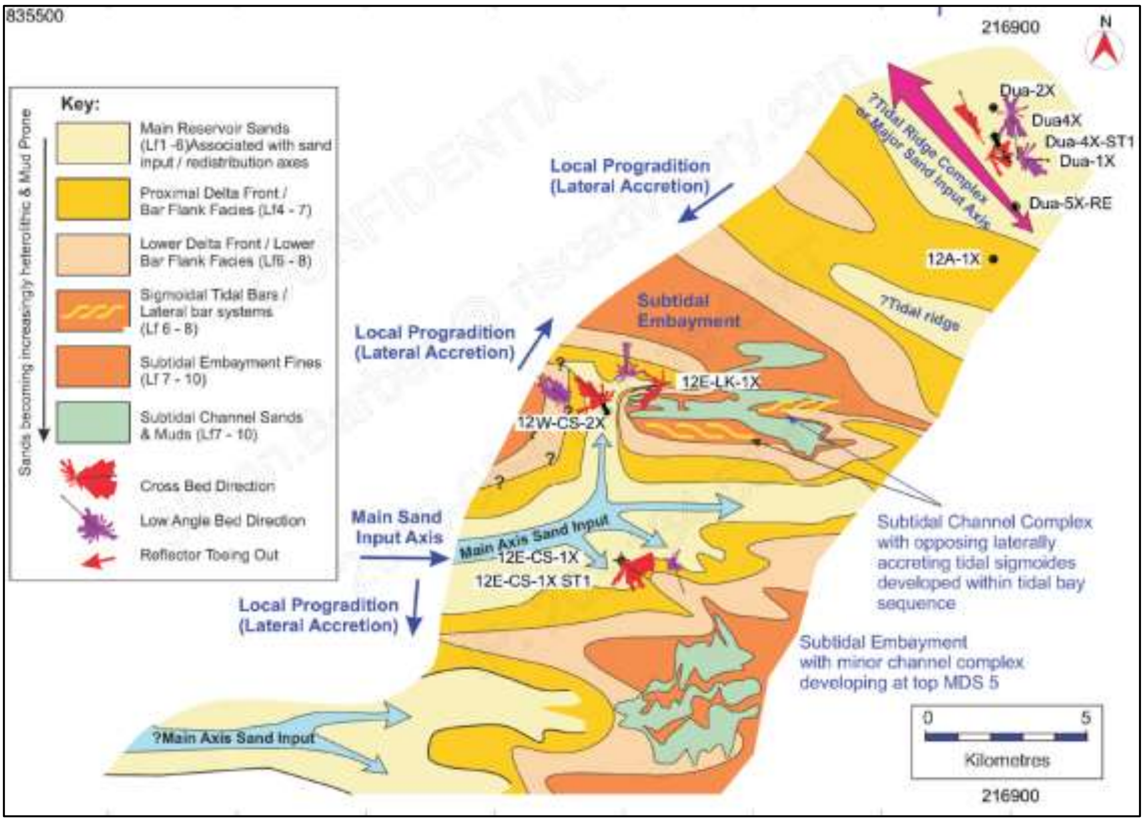


**Figure 4-6: MD5 Depositional Facies Map**[5]

[5] Oolithica Geoscience Ltd Geological Model Concept Review for MDS Static Model Rebuild Chim Sáo Field, Offshore Vietnam

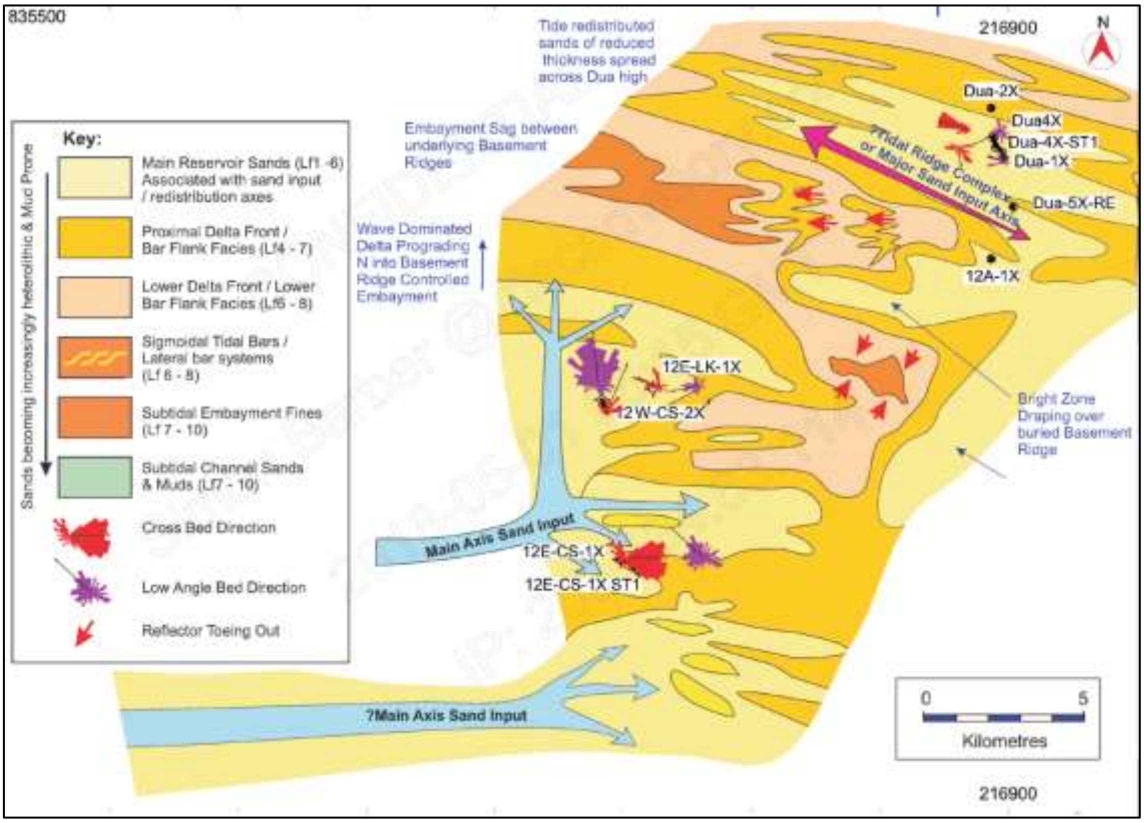


**Figure 4-7: MD6 Depositional Facies Map[5]**

The MDS1 and MDS0 reservoirs have been less studied. The 2016 model and report by subsurface consultants Oolithica[5] integrated the limited core from 12W-CS-2X well and petrographic data and interpretation of twenty-two existing wells into an updated static model.

A marked north-south facies change is noted across the field in the MDS1 with more sand prone facies predominant in the south of the field. Review of the inverted seismic clay volume led Oolithica to the interpretation that the increased sand in the south of the field was a result of a significant incised valley fill complex in the south of the field. The interpreted channel belt appears to be broadly meandering from west to east, Figure 4-8.

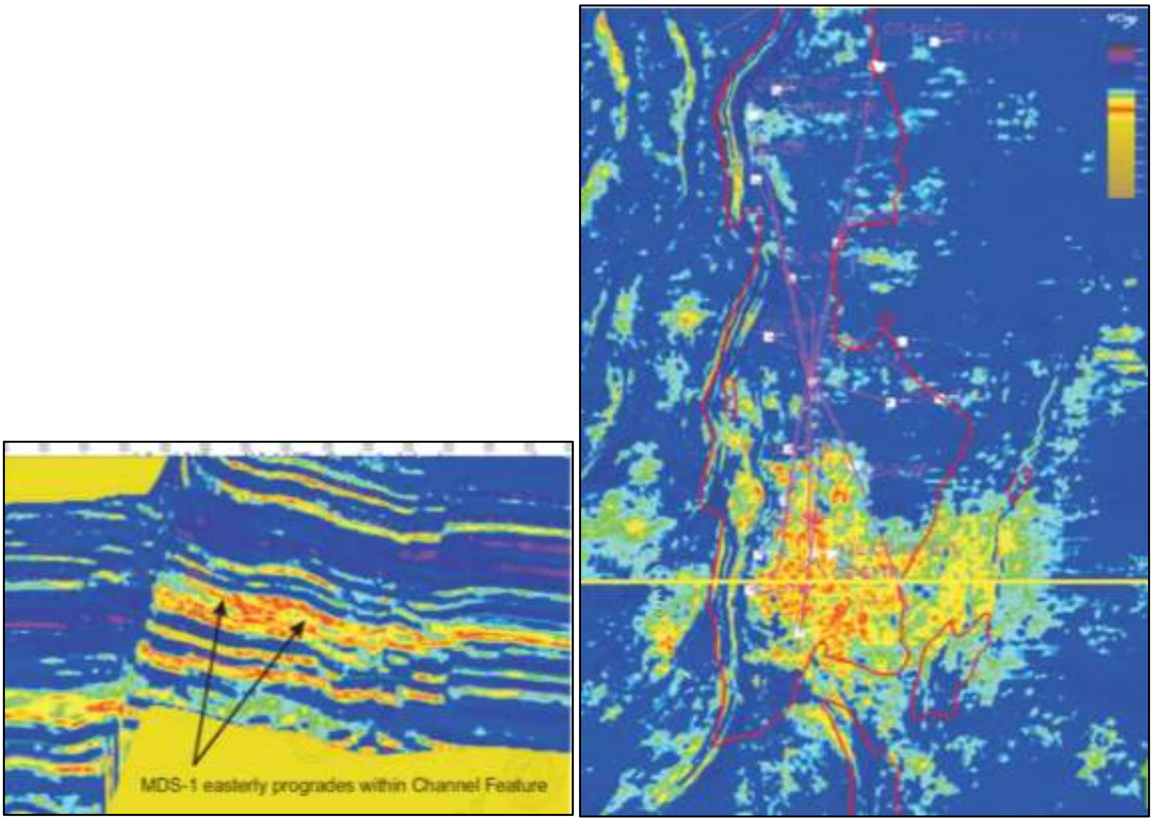


**Figure 4-8: MDS1 Inverted Seismic showing incised channel feature in southern area of Chim Sáo field**

The Oolithica reservoir model interpretation which has been the basis for the static models created over the field is considered reasonable. Santos provided a Petrel Static Model for the MDS reservoirs from November 2016 for RISC's review.

### 4.2.3. Petrophysical interpretation

RISC has reviewed petrophysical work undertaken by the Joint Venture over the Chim Sáo and Dua fields. A Petrophysical review of Chim Sáo was conducted by Santos in 2012. A petrophysical field study was conducted over Dua and Chim Sáo by Schlumberger on behalf of Premier in 2007.

The Santos 2012 study had access to core data through the MDS5 and MDS6 reservoir in three of the Chim Sáo wells. The study used well log data from eighteen wells. Wire line log data was available for six of the wells and LWD data was available for the remaining wells. The wireline data was environmentally corrected by Santos whereas the LWD data was environmentally corrected by the Contractor.

In the Santos 2012 study, the petrophysical uncertainties in derived porosity, permeability and water saturation have been constrained by the availability of core data from the MDS5 and MDS6 reservoirs. The only other cored interval was the water bearing MDS1 reservoir in CS-2X. No cores have been taken in any of the other Chim Sáo reservoir intervals.

Produced formation water has been collected and analysed. The Santos 2012 petrophysical study used a Rw of 0.435 ohmm and 0.403 ohmm at 24°C for the MDS5 and MDS6 reservoirs respectively. This was increased from previous studies which had Rw's of 0.206 ohmm at 25°C for the MDS5 and MDS6 reservoirs. This change in increased Rw resulted in an increase in interpreted water saturation (Sw) and a subsequent reduction in calculated oil saturation (So) across the MDS5 and MDS6 reservoirs.

The reservoir properties used in the resource estimate of Premier in 2016 are provided in Figure 4-9.

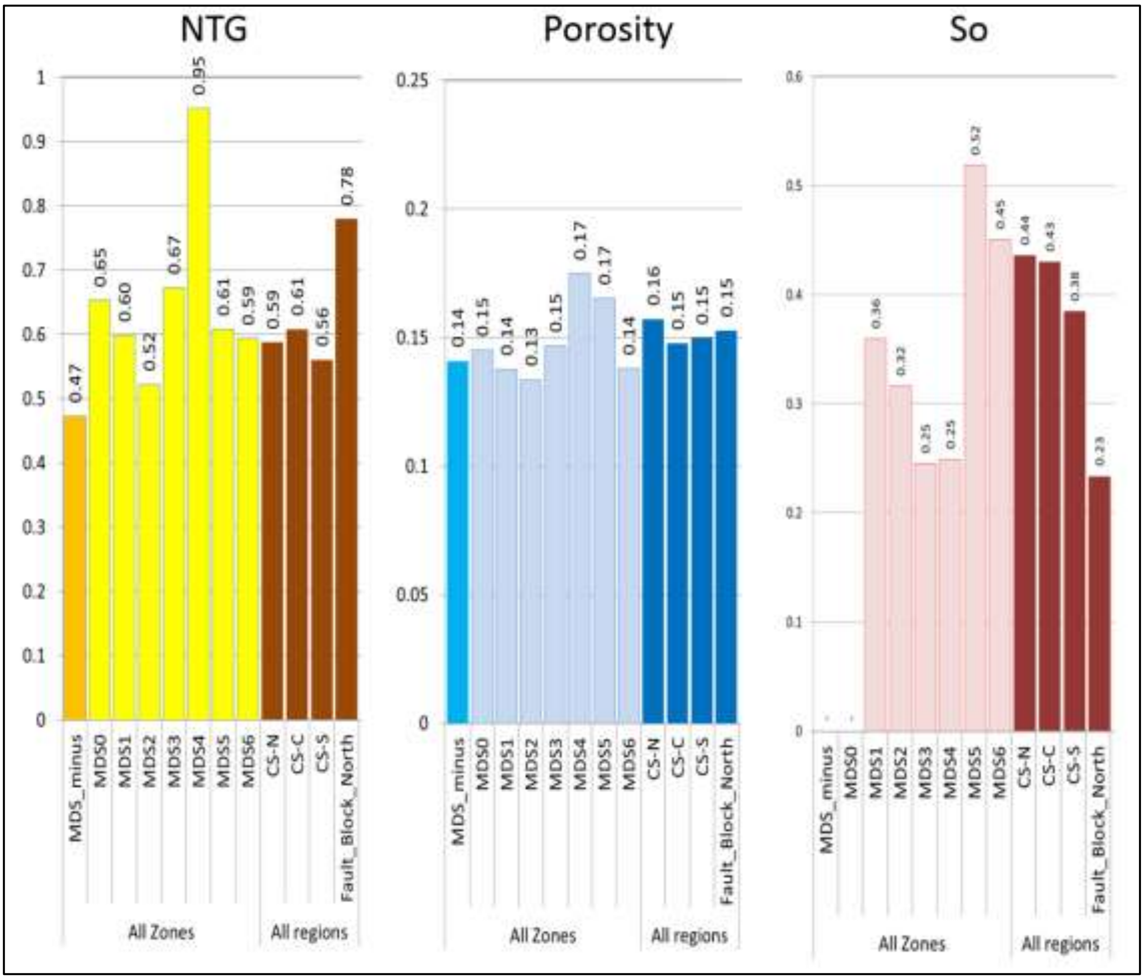


**Figure 4-9: Reservoir properties used in the Premier 2016 STOIIP estimate for Chim Sáo**

The interpretation of oil saturation will have an impact on the range of STOIIP. The current static model has no uncertainty in reservoir properties resulting in a very tight STOIIP range of (+/- 1.7%).

Ophir have used an oil saturation range of 45%/55%/65% for the MDS5 reservoir in their estimation of STOIIP (Figure 4-10). RISC supports this range.

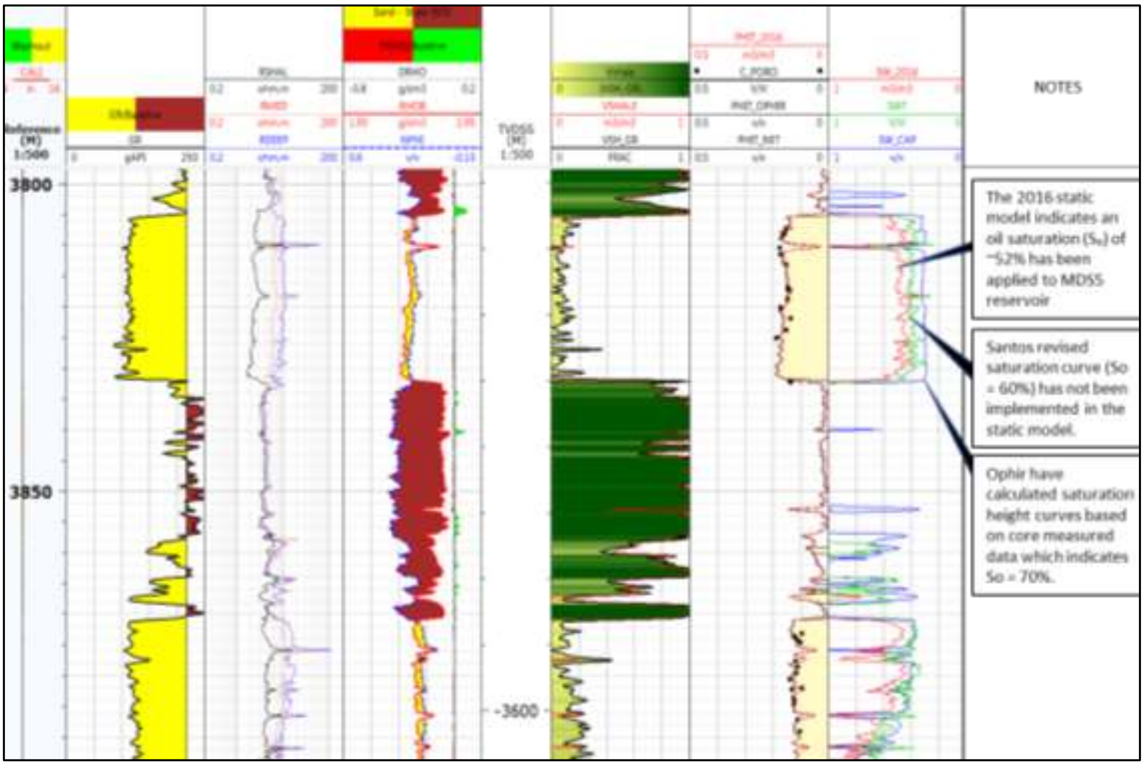


**Figure 4-10: MDS5 Reservoir oil saturation interpretation**

### 4.2.4. Fluid contacts

The pressure data indicates a free water level (FWL) from 3,601 m to 3,604 m TVDSS. However, the MDS5 reservoir has a FWL of 3,608 m TVDSS set by the mapped lowest closing contour Figure 4-11. The gas cap in the MD5 reservoir supported by production history matching indicates a GOC at 3,478 m TVDSS.

Although pressure data indicates a FWL from 3,637.1 m to 3,638.5m TVDSS, the MDS6 reservoir also has a FWL of between 3,620 m and 3,632 m TVDSS defined by well data and mapping uncertainty. The oil water contact has been set at 3,632 m TVDSS. The gas cap in the MD6 reservoir supported by production history matching indicates a GOC at 3,572 m TVDSS.

The MDS1 reservoir has a lowest Oil Down To (ODT) depth of 3,335 m TVDSS. The interpreted free water level (FWL) from a reservoir pressure versus depth plot of 3,330 m TVDSS exhibit three different oil gradients and suggests compositional variation. An alternative FWL of 3,325 m TVDSS can be made by using the S10P well aquifer points which are offset by 10 psi. The MDS1 reservoir does not have a gas cap.

A cross section across the Chim Sáo main field illustrates the fluid contacts, Figure 4-12 with the location of the cross section shown in Figure 4-11.

RISC supports the Santos interpretation of the Chim Sáo main field reservoir fluid contacts.

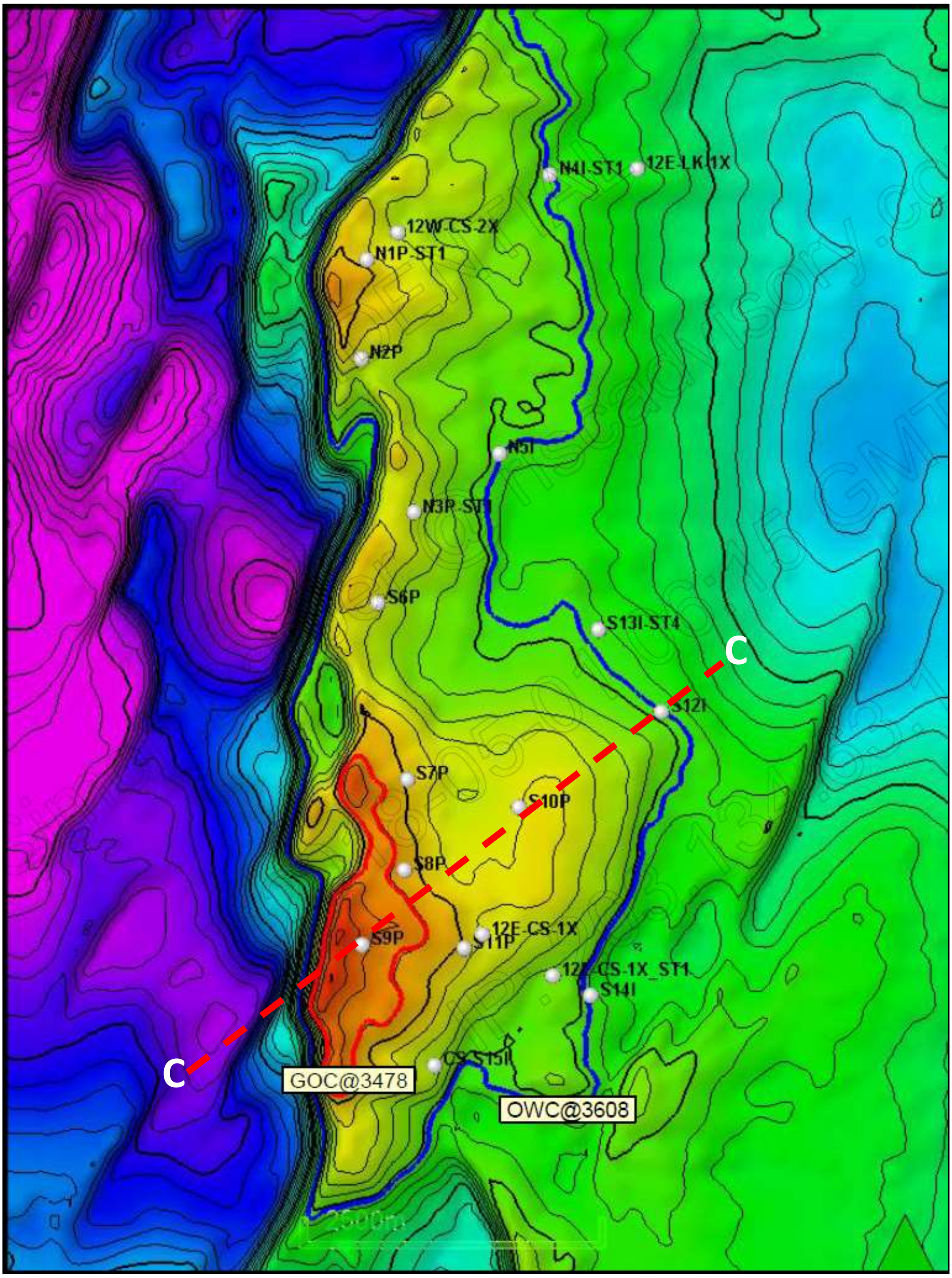


Figure 4-11: Chim Sáo MDS5 Reservoir Structure Map and Fluid Contacts

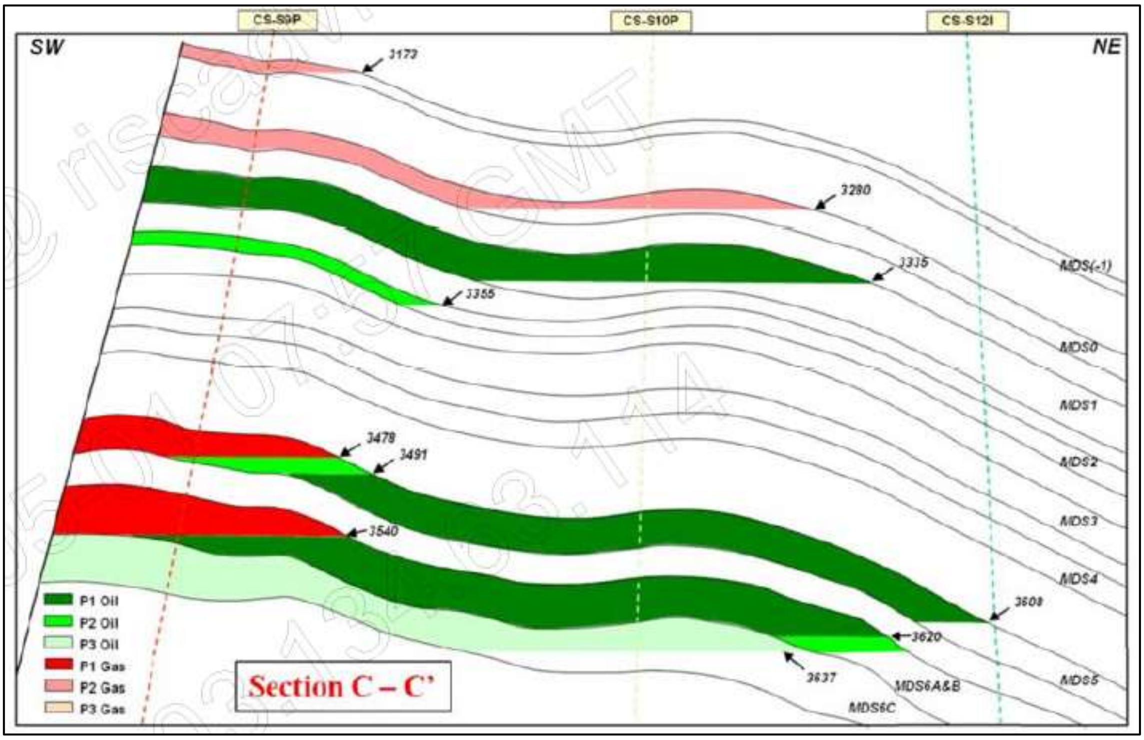


**Figure 4-12: SW-NE Section across the Chim Sáo main field**

## 4.2.5. Fluid properties

Chim Sáo fluid samples were taken using the MDT tool and during well tests on CS-1X, CS-2X, CS-S10P and CS-N17XP. The average fluid properties are shown in Table 4-1. The oil has high wax content of 20% and a pour point of 40°C.

**Table 4-1: Chim Sáo Oil properties**

| Sand | Pressure | Bo | GOR | Viscosity | API Gravity |
|---|---|---|---|---|---|
| | psia | rb/stb | scf/stb | cp | |
| **UDS1** | 4122 | 1.685 | 1170 | 0.307 | 42.6 |
| **UDS2** | 4223 | 1.815 | 1386 | 0.249 | 42.9 |
| **UDS3** | 4336 | 1.652 | 1089 | 0.459 | 40.5 |
| **MDS1** | 4737 | 1.524 | 950 | 0.352 | 40.3 |
| **MDS5** | 5067 | 1.594 | 998 | 0.414 | 42.2 |
| **MDS6** | 5137 | 1.573 | 913 | 0.381 | 41.9 |

As reported by the Operator, fluid sample analysis taken by MDT and well tests show a saturation pressure versus depth trend and a small gas cap in MDS5 and MDS6. The oil samples from the exploration and appraisal wells which were taken in the middle of the oil column were undersaturated. The saturation pressure versus depth trend became apparent after November 2011, when testing S9P well, which tested wet gas instead of oil at the crest of the field. The results of the gas analysis indicated a gas gravity of 0.83, a CGR of 55 stb/MMscf and about 6 mol% inert gases.

Dua oil properties are shown in Table 4-2.

**Table 4-2: Dua Oil properties**

| Sand | Pressure | Bo | GOR | Viscosity | API Gravity |
|---|---|---|---|---|---|
| | Psig | rb/stb | scf/stb | cp | |
| **MDS1** | 4590 | 1.704 | 1145 | 0.217 | 39.5 |
| **Upper Dua** | 4388 | 1.749 | 1247 | 0.333 | 39.1 |
| **MDS3** | 4490 | 1.956 | 1471 | 0.208 | 42.6 |

The Dua-1X well tested the gas in MDS1 sand but no PVT analysis of the gas has been reported. The only information on the quality of the gas reported has been that the gas has a gravity of 0.73. The measured gas and condensate rates during the test show a CGR of about 40 bbl/MMscf.

Primary stage separator gas from MDS5 has been analysed and contains 7 mol% $CO_2$, 0.2 mol% nitrogen and no $H_2S$. It has a gas gravity of 0.8 and HHV of 1,221 BTU/scf (1.29 PJ/Bcf).

## 4.3. Historical Production Analysis

The Chim Sáo field has produced since November 2011 and the Dua field since 2014. Gross cumulative oil production from both fields was 57.4 MMstb as of May 2018. The peak oil production rate was about 30,000 stb/d and the current rate is about 25,000 stb/d.

Chim Sáo field has thirteen producers and seven water injectors. One producer and injector are in Chim Sáo NW. Dua field has three producers. RISC has conducted decline curve analysis (DCA) on a well by well basis to estimate validate developed reserves. Details in section 4.4.2.

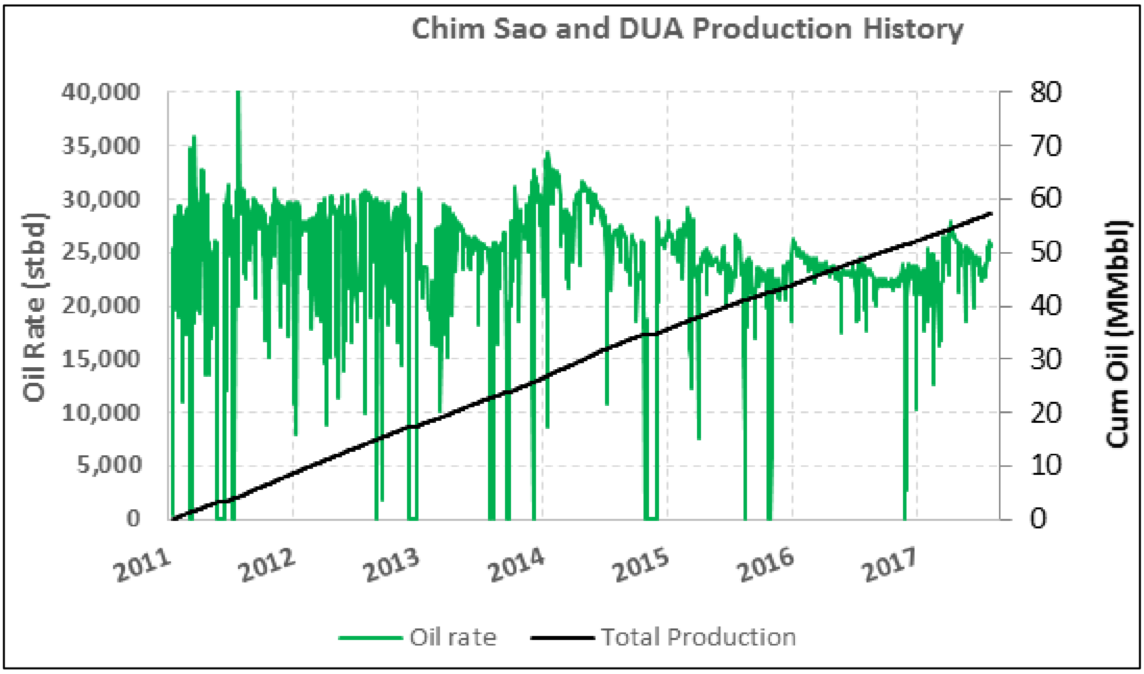


**Figure 4-13: Chim Sáo and Dua Oil Production History**

## 4.4. Resources

### 4.4.1. In-place resource volumes

The Operator's 2016 STOIIP estimates are shown in Figure 4-14. Approximately 94% of the Chim Sáo STOIIP is in the MDS5, MDS6 and MDS1 reservoirs.

RISC has independently estimated the STOIIP of the MDS5, MDS6, and MDS1 reservoirs using grids provided in the Premier 2016 static model and reservoir parameter ranges as provided in Figure 4-9 and supporting documentation found within the Santos Virtual Data room[6].

For the MDS5 reservoir, RISC calculated a STOIIP range of between 94 and 116 MMstb and a P50 of 105 MMstb compared with a 112.9 MMstb high case estimated by Premier.

The MDS5 top and base reservoir maps used for the RISC STOIIP estimate are provided in Figure 4-15. Similar mapping and volume work was carried out on the MDS6 top and base reservoir and the MDS1 top and base reservoir.

[6] 01.01 Project Jaguar – Block 12W Management Presentation.pdf

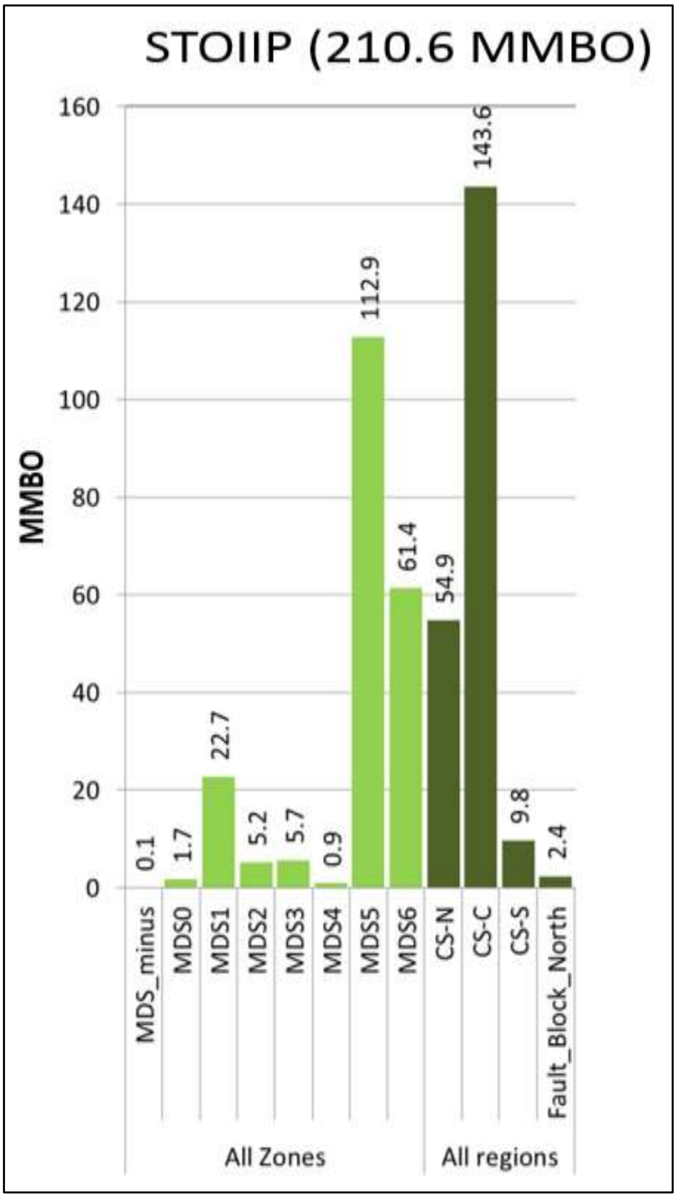


**Figure 4-14: Premier 2016 break down by reservoir of Chim Sáo STOIIP estimate**

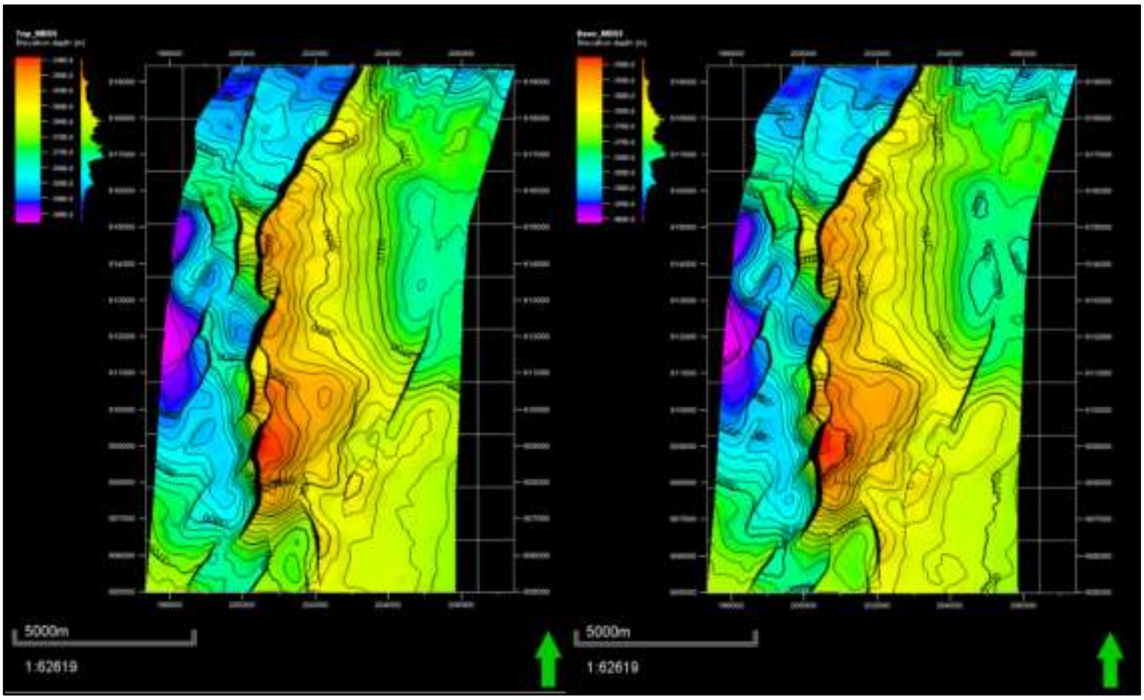


**Figure 4-15: Top and Base MDS5 input maps for RISC STOIIP estimate**

The reservoir parameter inputs and STOIIP estimate for the MDS5 reservoir are presented in Table 4-3.

**Table 4-3: MDS5 STOIIP estimate and reservoir parameter inputs**

| RISC REP | P99 | P50/Single | P1 |
|---|---|---|---|
| FWL contact | 3,601 | | 3,608 |
| Gas-Oil contact | | 3,478 | |
| NTG | | 0.61 | |
| So | 45% | 55% | 65% |
| Porosity | | 0.17 | |
| FVF (rb/stb) | 1.597 | | 1.704 |
| **RISC STOIIP (P90-P50-P10)** | **94** | **105** | **116** |

For the MDS6 reservoir RISC calculate a STOIIP range of between 46 and 62 MMstb and a P50 of 54 MMstb compared with a 61.4 MMstb high case estimated by Premier.

The reservoir parameter inputs and STOIIP estimate for the MDS5 reservoir are presented in Table 4-4.

**Table 4-4: MDS6 STOIIP estimate and reservoir parameter inputs**

| RISC REP | P99 | P50/Single | P1 |
|---|---|---|---|
| FWL contact | 3,620 | | 3,632 |
| Gas-Oil contact | | 3,572 | |
| NTG | | 0.59 | |
| So | 35% | 45% | 55% |
| Porosity | | 0.14 | |
| FVF (rb/stb) | 1.572 | | 1.652 |
| **RISC STOIIP (P90-P50-P10)** | **46** | **54** | **62** |

For the MDS1 reservoir RISC calculate a STOIIP range of between 14 and 19 MMstb and a P50 of 16 MMstb compared with a 23 MMstb high case estimated by Premier.

The reservoir parameter inputs and STOIIP estimate for the MDS1 reservoir are presented in Table 4-5.

**Table 4-5: MDS1 STOIIP estimate and reservoir parameter inputs**

| RISC REP | P99 | P50/Single | P1 |
|---|---|---|---|
| FWL contact | 3,320 | | 3,335 |
| Gas-Oil contact | | NO GAS CAP | |
| NTG | | 0.59 | |
| So | 30% | 35% | 40% |
| Porosity | | 0.14 | |
| FVF (rb/stb) | 1.594 | | 1.605 |
| **RISC STOIIP (P90-P50-P10)** | **14** | **16** | **19** |

### 4.4.2. Developed Reserves

RISC conducted decline curve analysis (DCA) on a well by well basis using data up to end August 2017 as more recent (by well) data was not made available until after RISC's analysis was completed. Both exponential and harmonic decline curves can be fitted to the production history. A 20:80 weighting between exponential and harmonic has been used for 1P reserves and a harmonic fit has been used to estimate 3P reserves. The 2P reserves case has used a best fit intermediate curve. Wells, CS S8P and CS S9P have not cut water or exhibited production rate decline yet. Recent (March 2018) well test data in combination with the operator's simulation results were used subjectively to guide the start of decline (water production) and an average well decline rate was applied.

Production data related to the two 2017 infill wells that came onto production late 2017 is limited to well test reports. Well 20P is producing dry oil at about 3,000 bpd. Well 5IP is producing dry oil at about 2,000 bpd. RISC has applied an average plateau period followed by an average decline rate guided by operator simulation results to forecast production in these wells.

The well decline curve forecasts were adjusted to match the field cumulative production at year end 2017 and the latest field data to end March 2018.

The total field decline was then compared with harmonic and exponential decline for sum of the wells. The low case (exponential) appeared conservative, therefore a 1P weighted average between the exponential and harmonic was provided for a better match to full field decline. Harmonic was retained as 3P and 2P is midway between 1P and 3P. The change in 1P reserves has only been applied to the base case of developed reserves.

The Vendor's base case model (CS+DUA+CS N5 IP+CS 20P) results were compared to RISC developed producing forecasts shown in Figure 4-16.

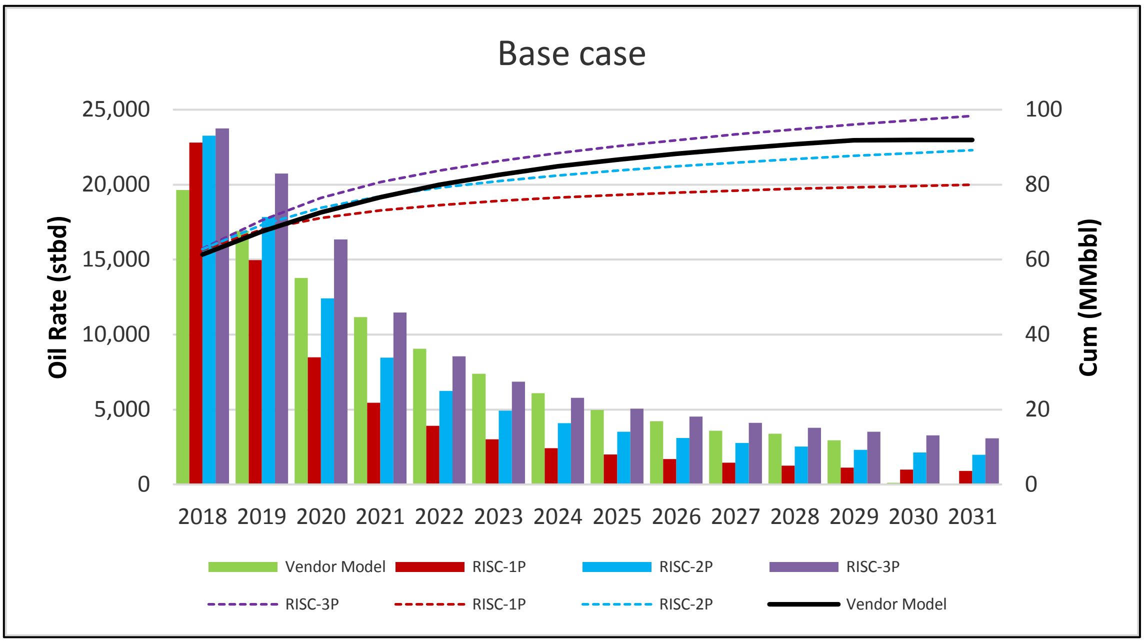


**Figure 4-16: Base Case (developed producing reserve) production comparison of RISC vs Vendor model**

The Vendor's forecast is based on mid-2017 history matched simulation and displays harmonic like decline. The Vendor's 2018 forecast is low compared to the 2018 year-to-date average of 24,800 bpd to 6 May 2018.

### 4.4.3. Undeveloped and Developed Non- Producing Reserves

Infill wells 20P and N5IP in 2017 were successful and another well (N21P) is planned for 2020. The 2017 wells have been estimated to provide an incremental 5,000 stb/d dry oil and 4.7 to 8.8 MMstb oil recovery per well. The 2020 infill well is expected to proceed given the 2017 success and has been classified by RISC as reserves. Further infill drilling may be matured but is classified as contingent resources at this stage.

The existing wells are largely completed on the MDS5 and 6 reservoirs with the potential to be recompleted on shallower reservoirs (MDS0, 1, 2, 3, 4) or have additional perforations added in the shallower intervals. In addition, well stimulation may also enhance well productivity.

Perforations in the UDS C3 reservoir were added to well N17XP in September 2016 increasing the wells oil rate by 2,000 bpd and adding 1 to 3 MMstb incremental reserves as shown in Figure 4-17.

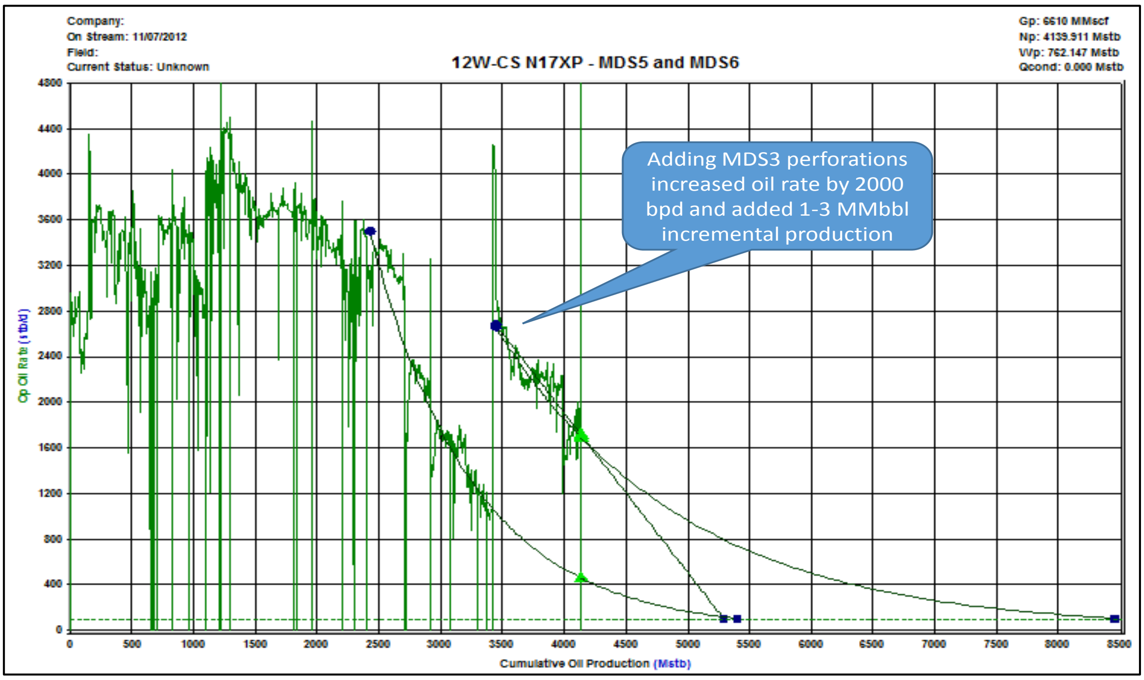


**Figure 4-17: Benefit of adding UDS C3 perforations in well N17XP Sept 2016**

Well N17XP is in Chim Sáo NW with the better quality UDS reservoir; the performance of these shallower reservoirs may be better than the shallower MDS reservoirs in Chim Sáo main.

Well 16XP discovered good quality reservoir and was completed on MDS1 reservoir (only) in Chim Sáo main. It has produced 2.1 MMstb to date with an estimated ultimate recovery of between 4 and 9 MMstb.

- In 2017 shallower perforations were successfully added to wells N1P and S9P in Chim Sáo main increasing oil production by 1,000 to 1,500 stb/d. There is not yet enough decline history to determine the additional incremental recovery. Subsequent well test indicates the boost to oil production in N1P was short lived but sustained in S9P.
- Shallower perforation in watered out well N2P restored production in 2017 to around 500 bpd but incremental recover appears limited.
- Therefore, two of the four wells with new shallow perforation (N17XP, S9P) have been successful.

RISC consider there is uncertainty in adding shallower perforations but estimate a mid-case volume of approximately 750 bopd per well and incremental oil production of 0.4 to 1.0 MMbbls per well.

The shallower MDS reservoirs MDS1-MDS4 in Chim Sáo main are estimated to contain 35 MMstb STOIIP with 23 MMstb in MDS1. Unlike the main MDS5 and MDS 6 reservoirs, these shallower reservoirs do not have a gas cap. Pressure support and recovery may be limited. The MDS1 reservoir has water injection from injector 18I.

The 2018 well work programme includes re-perforation of existing zones (to enhance productivity) and four firm wells with new perforations in shallower intervals. New shallower perforations in two other wells are contingent work. RISC assigns 3,000 bpd incremental oil and 1.6 to 4 MMstb incremental developed non-producing reserves to these four wells. RISC estimate that additional candidates for adding new shallower perforations will be identified in 2019 and includes the two contingent wells on the 2018 work programme.

**Table 4-6: Developed Non-producing recovery from additional shallow perforations**

| Year | Well new completions | Parameter | 1P | 2P | 3P |
|---|---|---|---|---|---|
| 2018 | 4 | Initial Rate | 2,000 | 3,000 | 3,500 |
| | | EUR (MMbbl) | 1.6 | 2.8 | 4 |
| 2019 | 2 | Initial Rate | 1,000 | 1,500 | 1,750 |
| | | EUR (MMbbl) | 0.8 | 1.4 | 2 |

Ongoing scale clean-out and acid stimulation has less significant effect on well performance and is estimated to be included in the decline analysis.

2018 and 2019 well work along with the 2020 infill well (N21P) profiles were added to the base case (Section 4.4.2) and compared against the Operator's Vendor model. RISC has assumed production start-up for well work and infill well to be in middle of the year.

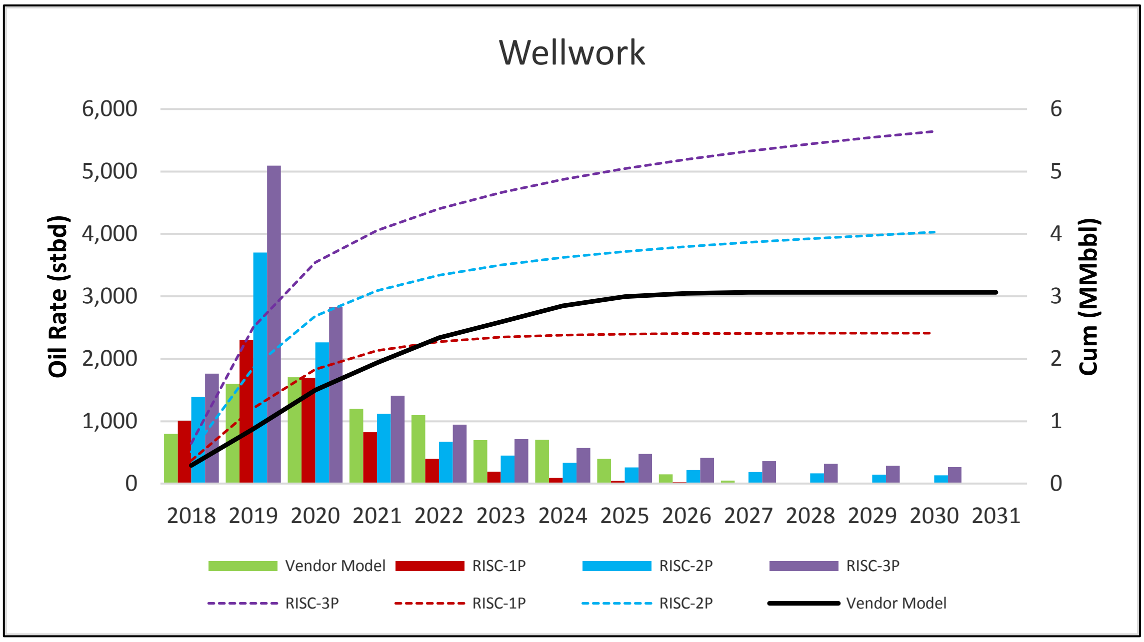


**Figure 4-18: Well work production comparison of RISC vs Vendor model**

RISC's incremental recovery estimates for well work in 2018 and 2019 are 2.4, 4.0 and 5.6 for 1P, 2P and 3P cases.

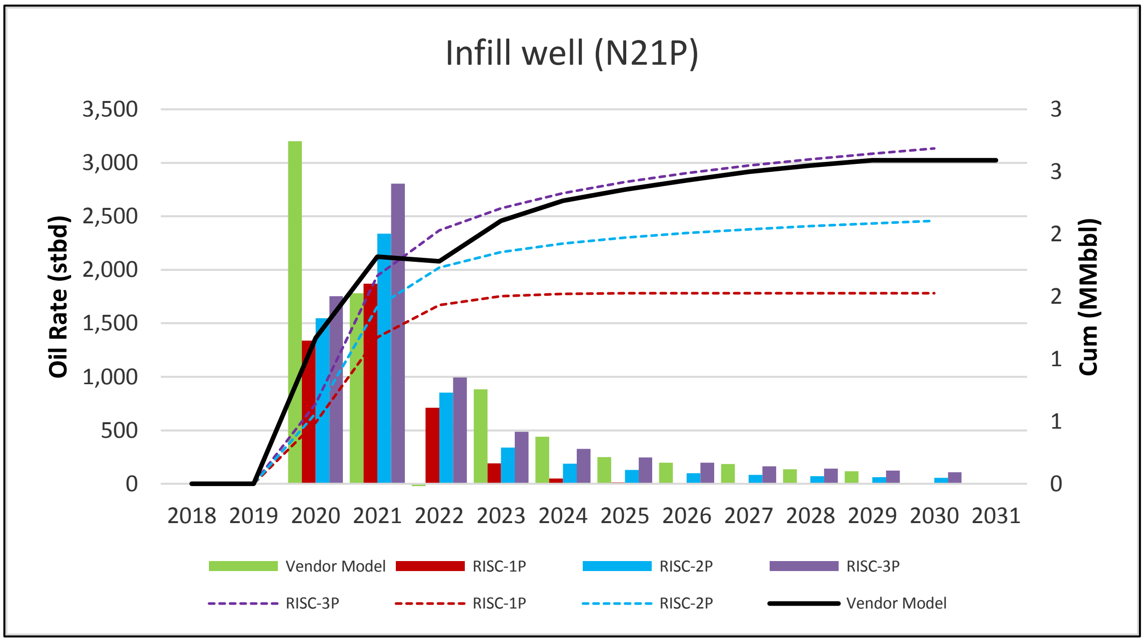


**Figure 4-19: N21P infill well production comparison of RISC vs Vendor model**

The Vendor forecast appears to assume start-up at the beginning of 2021. RISC assume a mid-2021 start-up with drilling expenditure in 2021. RISC has estimated 1P, 2P and 3P incremental reserves of 1.5, 2.1 and 2.7 MMbbl respectively for the 2020 infill well.

Figure 4-20 shows the total forecast (base + well work + infill).

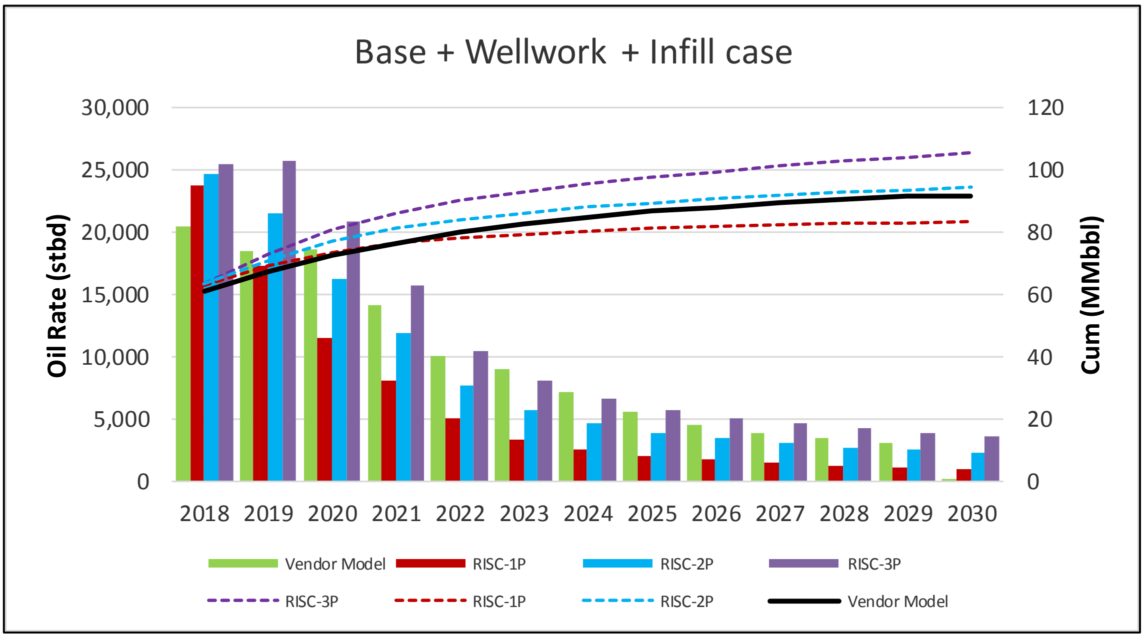


**Figure 4-20: Total (Base case + Well work + N21P) production comparison of RISC vs Vendor model**

Based on the good agreement between RISC's decline curve analysis and the reservoir simulation projections provided by the Vendor, RISC supports the Vendor model 2P recovery estimates on Chim Sáo and Dua Fields. However, RISC has generated its own 1P, 2P and 3P oil production forecasts that better reflect the 2018 production to date which has been higher than previously forecast.

The value of gas exports from Chim Sáo is small compared to oil production. Currently gas production is controlled to optimise oil production and minimise flaring. As gas production declines, gassy wells can be opened to maintain fuel gas requirements and some gas export.

RISC has estimated gas production using the simulated GOR adjusted to the latest production data. RISC has increased late time GOR and gas production in line with the Operators estimates.

Table 4-7: Block 12W Gross reserves as at 1 January 2018

| Oil and Gas | Unit | Gross Reserves | | |
|---|---|---|---|---|
| | | 1P | 2P | 3P |
| **Total Sales Gas** (Chim Sáo + Dua Field) | **Bcf** | **18.2** | **28.5** | **47.0** |
| **Total Oil** (Chim Sáo + Dua Field) | **MMstb** | **22.1** | **33.4** | **45.0** |

Notes:

1. Gross reserves are on 100% contractor entitlement basis and mid-price case and exclude production beyond 2030.
2. Sales Gas resources have been adjusted for shrinkage and fuel gas as detailed in Section 5.4.
3. The notional reference point for gas is entry to Nom Con Son pipeline and for oil is exit FPSO.
4. Deterministic evaluation methods have been used.
5. Additions beyond the field level have all been made arithmetically.
6. Sales gas conversions (HHV) for the Chim Sáo and Dua fields are 1.29 PJ/Bscf.

Table 4-8: Block 12W Net reserves as at 1 January 2018

| Gas and Condensate | Unit | Net Reserves | | |
|---|---|---|---|---|
| | | 1P | 2P | 3P |
| **Total Sales Gas** (Chim Sáo + Dua Field) | **Bcf** | **5.8** | **9.1** | **15.0** |
| **Total Oil** (Chim Sáo + Dua Field) | **MMstb** | **7.0** | **10.6** | **14.3** |

Notes:

1. Sales Gas resources have been adjusted for shrinkage and fuel gas as detailed in Section 5.4.
2. Net reserves are on a PSC entitlement basis and mid-price case and exclude production beyond 2030.
3. The notional reference point for gas is entry to Nom Con Son pipeline and for oil is exit FPSO.
4. Deterministic evaluation methods have been used.
5. Additions beyond the field level have all been made arithmetically.
6. Sales gas conversions (HHV) for the Chim Sáo and Dua fields are 1.29 PJ/Bscf.

### 4.4.4. Contingent Resources

Additional infill drilling and re-completions to shallower reservoirs may generate additional contingent oil resources. The STOIIP estimated by RISC and success of 2017 infill wells suggests further infill drilling may be worthwhile. However, such projects have not be identified or quantified by the Operator. RISC estimate two further infill wells recovering 2 MMstb each as contingent resources.

Contingent resources are related to potential gas blowdown in Dua and Chim Sáo fields near the end of oil production. The operator proposes:

- Blow down of Dua from 2021 using a sidetrack of Dua 2P with a shallower completion generating incremental contingent gas and oil resources;
- Potential blowdown of Chim Sáo using existing wells from 2025. This results in a loss of oil production but incremental gas production. As such the project is unlikely to go ahead.
-

RISC has reviewed the Operators production forecasts for these opportunities, consider then reasonable and include them as contingent resources, Table 4-9.

**Table 4-9: Gross Chim Sáo Contingent Resources (100%)**

| Contingent Resources | 2C Oil (MMbbl) |
|---|---|
| Further infill | 4.0 |
| Blowdown | 1.5 |
| Chim Sáo Depressurisation | -1.5 |
| Beyond Economic Limit | 2.5 |
| **Total** | **6.5** |

# 5. Development Plan and Costs

## 5.1. Development Plan

The Chim Sáo field is developed with a 16-slot wellhead platform tied back to the leased Lewek EMAS FPSO. The platform has twelve single slots and four dual slots allowing twenty wells to be drilled from the platform. Chim Sáo has thirteen production and seven Injection wells. The Dua field is producing through three subsea wells tied back approximately 17 km to the FPSO. The FPSO is moored in 96 m of water and is located approximately 350 km from land. Gas is exported to the Dinh Co Terminal via a 96 km 10” diameter pipeline that connects to the 26” Nam Con Son pipeline. Gas is sold to PetroVietnam for domestic power generation.

## 5.2. Capital costs

The valuation encompasses the Base Case (no further development) + Well work + Infill well. The infill well is estimated to cost $20 million. The well work is classified as operating cost.

RISC has made an allowance of $25 million in 2020 for life extension of the wellhead platform and infield lines as these have a design life of ten years and were installed between 2010 and 2011. Other elements of the production system have a longer design life.

## 5.3. Operating costs

Production operations costs are budgeted to be $111 million in 2018 plus $7 million of support costs. The largest component of operating cost is the FPSO lease rate. RISC has reviewed the contract rate and has seen reference to a production linked FPSO charge which is modelled in the cost forecast. Other operating costs have been held constant throughout field life.

The other component of operating costs is ‘well work’ which consists of relatively low cost well intervention operations such as perforating, scale removal and acid stimulation. The total cost of the campaign is estimated to be $6 million over the period between 2018 and 2025.

## 5.4. Abandonment costs

RISC has reviewed a range of estimates for total well P&A and facility abandonment and removal costs for Chim Sáo and Dua from between approximately $170 million to over $200 million. RISC has used an estimate within this range for the economics and Santos advise $141 million gross has already been paid at end 2017 with the balance outstanding. These costs are incurred on a unit of production basis.

# 6. Commercial

The economic model used to calculate Net Present Values (NPV) for the assets under review in this CPR have been audited by RISC (UK) Limited and an independent third party and is considered to be fit for purpose by all parties.

A summary of the parameters used in the economic valuation can be found in the following sections.

## 6.1. Summary of Economic Parameters

Economic assessment of the fields has been based on estimates of future production of assessed reserves/resources, forecasts of future capital and operating costs, and the PSC terms. The economic models and data input have been based on 100% project cash flows. Santos's share of value of each asset has then been determined by applying Santos's working interest to the resulting project NPVs.

- Hydrocarbon volume entitlement has been calculated according to the terms of the PSC consistent with industry practice for reporting reserves for interests held under PSCs.
- RISC has not applied adjustments for risk.
- RISC has not valued the hedges.
- RISC has relied on independent legal opinion that Block 12W PSC shall expire in 2030 and has used this date to calculate volumes and values.
- Block 12W original PSC effective November 2000 was for a 25-year term for oil and a 30-year term for gas. The PSC was amended in 2007 to give a 30-year term without differentiation between oil and gas.
- RISC has relied on an independent third party to verify the treatment of Corporate Income Tax and the cross checking of this against historical financial statements of Corporate Income Tax payments filed with the Vietnam tax authorities.
- RISC has verified the Madura Offshore PSC contract terms were appropriate.
- Madura Offshore PSC signed 4 December 1997.
- Madura Offshore PSC Term: 30 years from Effective Date.
- RISC has verified the Sampang PSC contract terms were appropriate.
- Sampang PSC dated 4 December 1997.
- Sampang PSC Term: 30 years from Effective Date.
- The effective date for valuation is set at 1 January 2018.
- Inflation set at 2.5% nominal[7]. 2.5% p.a. applied to costs consistent with the nominal oil price forecast.
- Project NPVs are reported at a discount rate of 10% nominal.

[7]Nominal = Money of the day. Nominal prices, sometimes called current dollar prices, measure the dollar value of a product at the time it was produced. Real prices are adjusted for general price level changes over time, i.e., inflation (escalation) or deflation (de-escalation).

## 6.1.1. Oil Price

A premium to Brent quality oil of $3/barrel has been advised by a third party for modelling Chim Sáo oil production. This is based on an average premium to Brent realized in the last twelve months April 2017 to May 2018. The realized historical premium for Chim Sáo ranges from a low of $0.7/barrel in October 2015 to as high as $7.6/barrel in July and April 2012. RISC has used $3/barrel long term.

- A total of five oil price scenarios have been run (Figure 6-1):
  1) Average Brent oil price of $70/bbl in 2018 and $70/bbl flat in nominal terms long term (labelled '$70 LT' long term in tables);
  2) Average Brent oil price of $70/bbl in 2018 and $65/bbl flat in nominal terms long term from 2020 (labelled '$65 LT' long term in tables);
  3) Average Brent oil price of $70/bbl in 2018 and $60/bbl flat in nominal terms long term from 2021 (labelled '$60 LT' long term in tables);
  4) Average Brent oil price of $55/bbl in 2018 and $55/bbl flat in nominal terms long term (labelled '$55 LT' long term in tables);
  5) Average Brent oil price of $51/bbl in 2018 and $54/bbl flat in nominal terms long term from 2021 (labelled '$54 LT' long term in tables).

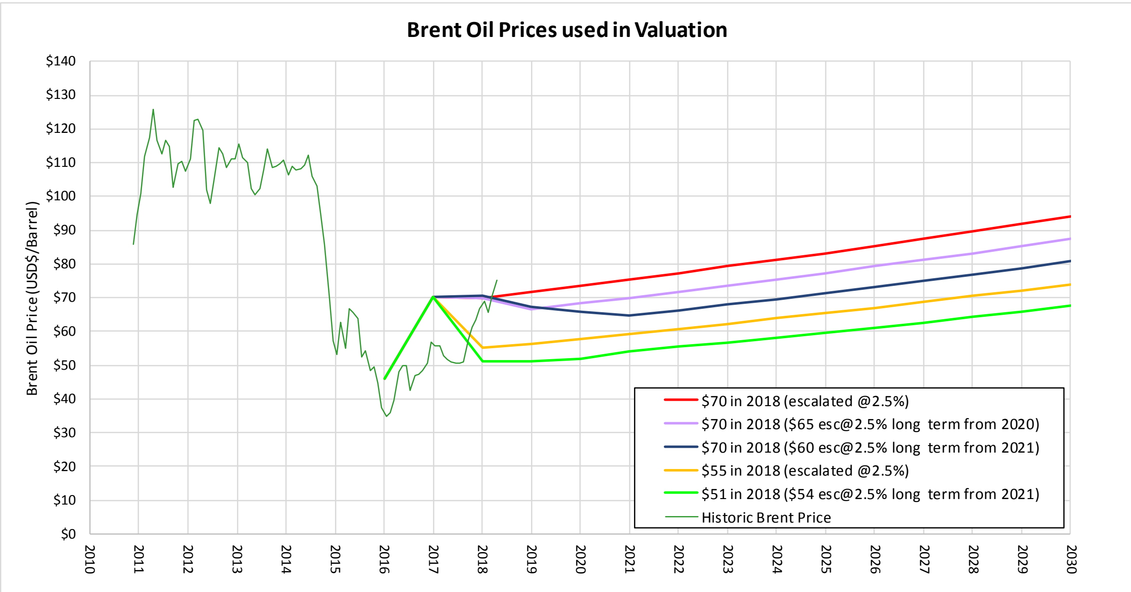


**Figure 6-1: Brent Oil Prices used in Valuation**

## 6.1.2. Condensate Price

- **Madura Offshore PSC and Wortel**: A condensate price of $49/barrel in 2018 flat in nominal terms long term and a sensitivity of $51/bbl in 2018 and $54/bbl flat in nominal terms long term from 2021.
- **Sampang – Oyong**: A condensate price of $58/barrel in 2018 flat in nominal terms long term and a sensitivity of $70/bbl in 2018 and $60/bbl flat in nominal terms long term from 2021.

Condensate volumes are low and as such the valuation is not sensitive to condensate price. RISC has reported a condensate price of $49/barrel in 2018 flat in nominal terms long term.

### 6.1.3. Gas Price

- **Vietnam**: Two price sensitivities were run on gas prices but have not been reported as the sensitivities represent less than 0.5% value change. The value calculated for the gas production represents less than 2% of the asset value.
- **Indonesia**: A set of local market prices for each field has been valued based on contracts and discussions with Santos as part of the data room exercise. These prices average out at approximately $7.0/mmbtu in 2018 and escalate at approximately 3.0% pa. RISC has reported a low side sensitivity with a gas sales price of $5.5/mmbtu in 2018 escalated at 2.5% pa.

## 6.2. Past petroleum costs

RISC has used past costs provided by Santos to calculate the Cost Recovery of each PSC. RISC has not audited the past costs but has relied on an independent audit report to confirm there are no material costs carried forward for cost recovery.

## 6.3. Economic results

The NPV estimates have not been adjusted for other factors (e.g. strategic, political and security risks) that a buyer or seller may consider in any transaction concerning these assets and therefore may not be representative of the fair market value. NPV's are in nominal terms at 1 January 2018 at 10% discount rate (Table 6-1, Table 6-2 & Table 6-3). All values are listed in US Dollars.

**Table 6-1: Summary of Net Present Value of assets in US$ million (1P case) with an Effective Date of 1 January 2018**

| 1P case | Oil Price (US$/Barrel) & NPV US$ million | | | | |
|---|---|---|---|---|---|
| **Area** | **$54 LT** | **$55 LT** | **$60 LT** | **$65 LT** | **$70 LT** |
| Madura | $9 | $9 | $9 | $9 | $9 |
| Sampang | $11 | $11 | $11 | $11 | $11 |
| **Indonesia** | **$20** | **$20** | **$20** | **$20** | **$20** |
| Chim Sáo | $112 | $130 | $162 | $165 | $178 |
| **Vietnam** | **$112** | **$130** | **$162** | **$165** | **$178** |
| **Total NPV** | **$132** | **$151** | **$182** | **$185** | **$198** |

**Table 6-2: Summary of Net Present Value of assets in US$ million (2P case) with an Effective Date of 1 January 2018**

| 2P case | Oil Price (US$/Barrel) & NPV US$ million | | | | |
|---|---|---|---|---|---|
| **US$ million** | **$54 LT** | **$55 LT** | **$60 LT** | **$65 LT** | **$70 LT** |
| Madura | $19 | $19 | $19 | $19 | $19 |
| Sampang | $15 | $15 | $15 | $15 | $15 |
| **Indonesia** | **$34** | **$34** | **$34** | **$34** | **$34** |
| Chim Sáo | $148 | $164 | $202 | $213 | $225 |
| **Vietnam** | **$148** | **$164** | **$202** | **$213** | **$225** |
| **Total NPV** | **$182** | **$199** | **$237** | **$247** | **$259** |

**Table 6-3: Summary of Net Present Value of assets in US$ million (3P case) with an Effective Date of 1 January 2018**

| 3P case | Oil Price (US$/Barrel) & NPV US$ million | | | | |
|---|---|---|---|---|---|
| **US$ million** | **$54 LT** | **$55 LT** | **$60 LT** | **$65 LT** | **$70 LT** |
| Madura | $28 | $28 | $28 | $28 | $28 |
| Sampang | $22 | $22 | $22 | $22 | $22 |
| **Indonesia** | **$50** | **$50** | **$50** | **$50** | **$50** |
| Chim Sáo | $177 | $206 | $256 | $270 | $292 |
| **Vietnam** | **$177** | **$206** | **$256** | **$270** | **$292** |
| **Total NPV** | **$226** | **$255** | **$306** | **$319** | **$342** |

The valuation with an Effective Date of 1 January 2018 (Table 6-4) is the Net Present Value of the forward production and costs from 1 January 2018 with historic costs before 1 January 2018 considered sunk but used in calculations for tax calculations and future tax payments. Valuation of cash flow is value at 1 January 2018.

The valuation with a Valuation Date of 1 July 2018 (Table 6-5) is the Net Present Value of the forward production and costs from 1 January 2018 with historic costs before 1 January 2018 considered sunk but used in calculations for tax calculations and future tax payments. Valuation of cash flow is value at 1 July 2018.

Asset NPVs for 1P, 2P and 3P reserves are reported at a nominal discount rate of 10%.

The economic values shown in this report have not been adjusted for other factors (e.g. strategic, political and security risks) that a buyer or seller may consider in any transaction concerning these assets and therefore should not be taken to be fair market values.

**Table 6-4: Summary of NPVs for Santos Assets in US Dollars with an Effective Date of 1 January 2018 & Valuation Date of 1 January 2018[1]**

| NPV US$ million | $54/Barrel Long Term | | | $60/Barrel Long Term | | | $70/Barrel Long Term | | |
|---|---|---|---|---|---|---|---|---|---|
| **Asset** | **1P** | **2P** | **3P** | **1P** | **2P** | **3P** | **1P** | **2P** | **3P** |
| Madura | $9 | $19 | $28 | $9 | $19 | $28 | $9 | $19 | $28 |
| Sampang | $11 | $15 | $22 | $11 | $15 | $22 | $11 | $15 | $22 |
| **Indonesia** | **$20** | **$34** | **$50** | **$20** | **$34** | **$50** | **$20** | **$34** | **$50** |
| Chim Sáo | $112 | $148 | $177 | $162 | $202 | $256 | $178 | $225 | $292 |
| **Vietnam** | **$112** | **$148** | **$177** | **$162** | **$202** | **$256** | **$178** | **$225** | **$292** |
| **Total NPV** | **$132** | **$182** | **$226** | **$182** | **$237** | **$306** | **$198** | **$259** | **$342** |

[1]Note: Historic costs before 1 January 2018 are considered sunk (Effective Date) but are used in calculations for tax calculations and future tax payments. The valuation of cash flow is value at 1 January 2018.

**Table 6-5: Summary of NPVs for Santos Assets in US Dollars with Effective Date of 1 January 2018 & Valuation Date of 1 July 2018[2]**

| NPV US$ million | $54/Barrel Long Term | | | $60/Barrel Long Term | | | $70/Barrel Long Term | | |
|---|---|---|---|---|---|---|---|---|---|
| **Asset** | **1P** | **2P** | **3P** | **1P** | **2P** | **3P** | **1P** | **2P** | **3P** |
| Madura | $9 | $19 | $28 | $9 | $19 | $28 | $9 | $19 | $28 |
| Sampang | $11 | $15 | $22 | $11 | $15 | $22 | $11 | $15 | $22 |
| **Indonesia** | **$20** | **$34** | **$50** | **$20** | **$34** | **$50** | **$20** | **$34** | **$50** |
| Chim Sáo | $118 | $155 | $185 | $170 | $212 | $269 | $187 | $236 | $307 |
| **Vietnam** | **$118** | **$155** | **$185** | **$170** | **$212** | **$269** | **$187** | **$236** | **$307** |
| **Total NPV** | **$138** | **$189** | **$235** | **$190** | **$246** | **$318** | **$207** | **$270** | **$356** |

[2]Note: Historic costs before 1 January 2018 are considered sunk (Effective Date) but are used in calculations for tax calculations and future tax payments. The valuation of cash flow is value at 1 July 2018. Cashflows between 1 January 2018 and 30 June 2018 are escalated to Valuation Date of 1 July 2018 at 10%.

# 7. Opportunities and risks

- Oil production from the Chim Sáo field has been better than originally forecast and the two infill wells in 2017 have successfully produced dry oil. Oil production has generally been higher than budget forecasts. Technical analysis suggests that the oil saturation and STOIIP may be greater than operator estimates. An infill well in 2020 and upward re-completion opportunities are planned. However, further infill drilling may be justified given the success of the 2017 well, although such opportunities, location and well planning needs to be developed.
- Both Madura Offshore PSC and Sampang PSC have their costs (capex and opex) recovered under the cost recovery mechanism in the PSCs. This provides minimum incremental capex and opex from the existing infrastructures to support developments of future discoveries in the PSCs.
- The first PODs (Plan of Developments) of both PSCs have already been approved by the Minister of Energy and Natural Resources. This enables Santos to have considerably faster POD approvals in the future as any subsequent PODs only require approvals from SKK Migas.
- Both PSCs are using different gas pipelines to transport their gas to East Java markets. Madura Offshore PSC is using EJGP (East Java Gas Pipeline) with landing point at Porong which can directly access gas markets in central and northern parts of East Java. Sampang PSC is using the 63 km PSC's gas pipeline to transport gas to Grati to access southern part of East Java. The recently operational Pertagas' 56 km 120 MMscfd capacity pipeline connects Grati and Porong and this allows gas from both PSCs to have flexibility to access all markets in East Java.
- The current ongoing Meliwis and Maleo gas sales negotiations with PGN (state-owned gas transmission and distribution company) may not be completed by the target date of July 2018. The Minister of Energy and Natural Resources has not yet approved the gas allocation and gas prices for Meliwis and Maleo.

# 8. List of terms

The following lists, along with a brief definition, abbreviated terms that are commonly used in the oil and gas industry and which may be used in this report.

| Term | Definition |
|---|---|
| 1P | Equivalent to Proved reserves or Proved in-place quantities, depending on the context. |
| 2P | The sum of Proved and Probable reserves or in-place quantities, depending on the context. |
| 2Q | 2nd Quarter |
| 2D | Two Dimensional |
| 3D | Three Dimensional |
| 4D | Four Dimensional – time lapsed 3D in relation to seismic |
| 3P | The sum of Proved, Probable and Possible Reserves or in-place quantities, depending on the context. |
| 3Q | 3rd Quarter |
| 4Q | 4th Quarter |
| AFE | Authority for Expenditure |
| Bbl | US Barrel |
| bbl/d | US Barrels per day |
| Bcf | Billion ($10^9$) cubic feet |
| Bcm | Billion ($10^9$) cubic metres |
| Bfpd | Barrels of fluid per day |
| bopd | Barrels of oil per day |
| BTU | British Thermal Units |
| Boepd | US barrels of oil equivalent per day |
| Bwpd | Barrels of water per day |
| °C | Degrees Celsius |
| Capex | Capital expenditure |
| CAPM | Capital asset pricing model |
| CGR | Condensate Gas Ratio – usually expressed as bbl/MMscf |
| Contingent Resources | Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent Resources are a class of discovered recoverable resources as defined in the SPE-PRMS. |
| $CO_2$ | Carbon dioxide |
| CP | Centipoise (measure of viscosity) |
| CPI | Consumer Price Index |
| deg | Degrees |
| DHI | Direct hydrocarbon indicator |
| Discount Rate | The interest rate used to discount future cash flows into a dollars of a reference date |
| DST | Drill stem test |
| E&P | Exploration and Production |
| Eg | Gas expansion factor. Gas volume at standard (surface) conditions/gas volume at reservoir conditions (pressure and temperature) |
| EIA | US Energy Information Administration |
| EMV | Expected Monetary Value |

| Term | Definition |
|---|---|
| EOR | Enhanced Oil Recovery |
| ESMA | European Securities and Markets Authority |
| ESP | Electric submersible pump |
| EUR | Economic ultimate recovery |
| Expectation | The mean of a probability distribution |
| °F | Degrees Fahrenheit |
| FDP | Field Development Plan |
| FEED | Front End Engineering and design |
| FID | Final investment decision |
| FM | Formation |
| FPSO | Floating Production Storage and offtake unit |
| FWL | Free Water Level |
| FVF | Formation volume factor |
| GIIP | Gas Initially In Place |
| GJ | Giga ($10^9$) joules |
| GOC | Gas-oil contact |
| GOR | Gas oil ratio |
| GRV | Gross rock volume |
| GSA | Gas sales agreement |
| GTL | Gas To Liquid(s) |
| GWC | Gas water contact |
| $H_2S$ | Hydrogen sulphide |
| HHV | Higher heating value |
| ID | Internal diameter |
| IRR | Internal Rate of Return is the discount rate that results in the NPV being equal to zero. |
| JV(P) | Joint Venture (Partners) |
| Kh | Horizontal permeability |
| $km^2$ | Square kilometres |
| Krw | Relative permeability to water |
| Kv | Vertical permeability |
| kPa | Kilo (thousand) Pascals (measurement of pressure) |
| Mstb/d | Thousand Stock tank barrels per day |
| LIBOR | London inter-bank offered rate |
| LNG | Liquefied Natural Gas |
| LTBR | Long-Term Bond Rate |
| m | Metres |
| MDT | Modular dynamic (formation) tester |
| mD | Millidarcies (permeability) |
| MJ | Mega ($10^6$) Joules |
| MMbbl | Million US barrels |
| MMscf(d) | Million standard cubic feet (per day) |
| MMstb | Million US stock tank barrels |

| Term | Definition |
|---|---|
| MOD | Money of the Day (nominal dollars) as opposed to money in real terms |
| MOU | Memorandum of Understanding |
| Mscf | Thousand standard cubic feet |
| Mstb | Thousand US stock tank barrels |
| MPa | Mega ($10^6$) pascal (measurement of pressure) |
| mss | Metres subsea |
| MSV | Mean Success Volume |
| mTVDss | Metres true vertical depth subsea |
| MW | Megawatt |
| NPV | Net Present Value (of a series of cash flows) |
| NTG | Net to Gross (ratio) |
| ODT | Oil down to |
| OGIP | Original Gas In Place |
| OOIP | Original Oil in Place |
| Opex | Operating expenditure |
| OWC | Oil-water contact |
| P90, P50, P10 | 90%, 50% & 10% probabilities respectively that the stated quantities will be equalled or exceeded. The P90, P50 and P10 quantities correspond to the Proved (1P), Proved + Probable (2P) and Proved + Probable + Possible (3P) confidence levels respectively. |
| PBU | Pressure build-up |
| PJ | Peta ($10^{15}$) Joules |
| POS | Probability of Success |
| Possible Reserves | As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. |
| Probable Reserves | As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. |
| Prospective Resources | Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations as defined in the SPE-PRMS. |
| Proved Reserves | As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. Often referred to as 1P, also as "Proven". |
| PSC | Production Sharing Contract |
| PSDM | Pre-stack depth migration |
| PSTM | Pre-stack time migration |
| psig | Pounds per square inch |

| Term | Definition |
|---|---|
| psia | Pounds per square inch pressure absolute |
| p.u. | Porosity unit e.g. porosity of 20% +/- 2 p.u. equals a porosity range of 18% to 22% |
| PVT | Pressure, volume & temperature |
| QA/QC | Quality Assurance/ Control |
| rb/stb | Reservoir barrels per stock tank barrel under standard conditions |
| RFT | Repeat Formation Test |
| Real Terms (RT) | Real Terms (in the reference date dollars) as opposed to Nominal Terms of Money of the Day |
| Reserves | RESERVES are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by development and production status. |
| RT | Measured from Rotary Table or Real Terms, depending on context |
| SC | Service Contract |
| scf | Standard cubic feet (measured at 60 degrees F and 14.7 psia) |
| Sg | Gas saturation |
| Sgr | Residual gas saturation |
| SRD | Seismic reference datum lake level |
| SPE | Society of Petroleum Engineers |
| SPE-PRMS | Petroleum Resources Management System, approved by the Board of the SPE March 2007 and endorsed by the Boards of Society of Petroleum Engineers, American Association of Petroleum Geologists, World Petroleum Council and Society of Petroleum Evaluation Engineers. |
| s.u. | Fluid saturation unit. e.g. saturation of 80% +/- 10 s.u. equals a saturation range of 70% to 90% |
| stb | US Stock tank barrels |
| STOIIP | Stock Tank Oil Initially In Place |
| Sw | Water saturation |
| TCM | Technical committee meeting |
| Tcf | Trillion ($10^{12}$) cubic feet |
| TJ | Tera ($10^{12}$) Joules |
| TLP | Tension Leg Platform |
| TRSSV | Tubing retrievable subsurface safety valve |
| TVD | True vertical depth |
| US$ | United States dollar |
| US$ million | Million United States dollars |
| WACC | Weighted average cost of capital |
| WHFP | Well Head Flowing Pressure |
| Working interest | A company's equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms. |
| WPC | World Petroleum Council |
| WTI | West Texas Intermediate Crude Oil |