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Rex International Holding Limited
1 George Street #14-01
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ECV 2143
20th March 2015

Dear Sirs,

EVALUATION OF SELECTED OIL RESERVES IN SOUTH ERIN BLOCK, TRINIDAD
as of 31st DECEMBER 2014

At the request of Rex International Holding Limited (ñRIHò), RPS Energy Consultants Limited (ñRPSò) has prepared an evaluation of selected oil Reserves and Resources and the net present values of those for South Erin Block, onshore Trinidad (ñSouth Erinò), as of 31st December 2014 (the ñServicesò). The South Erin licence is held by Jasmin Oil and Gas Limited (ñJasminò) which is 100% owned by Caribbean Rex Ltd (ñREXò) and RIH has 98.36% ownership of REX.

In preparing this report, we relied upon certain factual information and data furnished by RIH, with respect to ownership interests, production, historical costs of operation and development, product prices, agreements relating to current and future operations, sales of production, and other relevant data. The extent and character of all factual information and data supplied were relied upon by us in preparing this report and have been accepted as represented without independent verification. We have relied upon representations made by RIH as to the completeness and accuracy of the data provided and that no material changes in the performance of the properties has occurred nor is expected to occur, from that which was projected in this report, between the date that the data was obtained for this evaluation and the date of this report, and that no new data has come to light that may result in a material change to the evaluation of the Reserves presented in this report. No site visit has been undertaken by RPS as the production from existing wells is modest and the facilities are mature and of modest scale.

The oil bearing reservoirs at South Erin are the Pliocene Lower Forest and Mid Cruse Sandstones. Lower Forest Fm comprises lenticular delta-top sandstones and this overlies more extensive delta-front turbidites of the Cruse Fm. The majority of production in the licence to date, from five wells, is from the Lower Forest B1 sands.

This report is an update of a year-end 2013 Reserves and Resources Report produced by RPS for RIH (issued in March 2014). Development wells ER-105 and ER-106 were drilled in the field in December 2014 and this report incorporates the results from these wells plus the future drilling programme that includes four new development wells planned for 2015 or 2016.

Part of a 3D seismic survey has been purchased across the South Erin area and has been interpreted by Aggo Geoconcepts on behalf of REX but RPS has not evaluated this interpretation as RPS were only engaged to undertake this project by RIH shortly before the final report was due to be submitted. The RPS remit was to update the previous year-end Reserves report based on the 2014 production history, the new wells drilled and tested in 2014, and updated oil price and capex/opex estimates as insufficient time had been allowed for a review of the 3D seismic.

Depth structure maps were made available for this report but these maps pre-dated wells ER-105 and ER-106. RPS has adjusted the maps with the new well tops in order to make a volumetric estimation to confirm available STOIIP in part of the field drilled by ER-105. As RPSô Reserves estimates use well performance for the field rather than volumetric methods STOIIP estimation is not considered critical.

For the previous study by RPS the developed wells were considered representative of the future undrilled wells and (excluding 1ER-102) the average EUR was 82,000 barrels per well. A generalised decline curve was produced to give an EUR of 82,000 barrels with a rate of decline averaging the successful developed wells. This may be appropriate for most future wells. Test results from new well ER-105 demonstrate a reduction in production rate of 20% can be expected compared to previous wells and the decline curve and EUR have been revised. Test results for well ER-106 show a significant reduction in expected production.

Reserves are estimated for the following:

- Revised Reserves for the currently producing wells ER-98, ER-99, ER-100 and ER-101. No recompletions of these wells are planned.
- New Reserves for recent developed well ER-105. No Reserves are allocated to ER-106.
- Undeveloped Reserves for four planned wells to be drilled in 2015 or early 2016 in the vicinity of ER-105 discovery well and other areas of the field.

Economics have been determined for these Reserves and allow for Government Royalty, Petrotrin Overriding Royalty (ORR), Supplemental Petroleum Tax (SPT) and Operating Costs.

Reserves in South Erin attributable to RIHœs indirectly owned subsidiary Caribbean Rex Ltd (ñREXò) as of 31st December 2014 are summarised in the following table. RIH has 98.36% ownership of REX.

Category	Gross Attributable to Licence (Mstb)	Net Attributable to RIH [1,2] (Mstb)	Change in Net Attributable from Previous Update	Remarks
Reserves				
	Oil Reserves			
1P	170	117	+2.6%	*1P Reserves are uneconomic. Includes Undeveloped Reserves*
2P	331	229	-11.2%	*Includes Undeveloped Reserves*
3P	485	338	-24.6%	*Includes Undeveloped Reserves*

1. *Net Attributable is the net share of Reserves after the deduction of Government Royalty and Petrotrin Over-riding Royalty.*
2. *Rex International Holding Ltd has 98.36% ownership of Caribbean Rex Ltd which has 100% ownership of Jasmin Oil and Gas Limited.*

The cashflows associated with the three Developed Reserves cases and the three Developed plus Undeveloped Reserves cases, on a 98.36% WI basis, are presented in Appendix 2 of the main report.

The Services have been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. However, RPS Energy Consultants

Limited is not in a position to attest to the property title, financial interest relationships or encumbrances related to South Erin.

The evaluation reflects our informed judgement based on the SPE PRMS 2007 Standards, but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and engineering data. The reported hydrocarbon resource volumes are estimates based on professional engineering judgment and are subject to future revisions, upward or downward, as a result of future operations or as additional information become available.

We reserve the right to revise any estimates provided herein if any relevant data existing prior to preparation of this report were not made available, if any data between the effective date of the evaluation and the date of this report were to vary significantly from that forecast, or if any data provided were found to be erroneous.

Yours faithfully

On behalf of RPS Energy Consultants Limited

Gordon Taylor, C.Eng, C.Geol
Director, Head of Subsurface

EVALUATION OF SELECTED OIL RESERVES IN SOUTH ERIN BLOCK, TRINIDAD

AS OF 31st DECEMBER 2014

Prepared for
Rex International Holding Limited

RPS Energy Consultants Limited

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DOCUMENT REVISION RECORD

Document Description	Date	Issued by	Checked by	Accepted by Client	Comment
Version 01 ï Draft	19/03/15	G Smith	G Taylor		
Final Version					

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1. EXECUTIVE SUMMARY

At the request of Rex International Holding Limited (ñRIHò or ñCompanyò), RPS Energy Consultants Limited (ñRPSò) has prepared an evaluation of selected oil Reserves and the net present values of those Reserves for South Erin Block, onshore Trinidad (ñSouth Erinò), as of 31st December 2014.

No site visit has been undertaken by RPS as the production from existing wells is modest and the facilities are mature and of modest scale.

The oil bearing reservoirs at South Erin are the Pliocene Lower Forest and Mid Cruse Sandstones. Lower Forest Fm comprises lenticular delta-top sandstones and this overlies more extensive delta-front turbidites of the Cruse Fm. The majority of production in the licence to date, from some five wells, is from the Lower Forest B1 sands.

The 3D seismic data have been interpreted by Aggoo Geoconcepts on behalf of RIH but RPS has not been able to validate the interpretation. As RPSô Reserves estimates use performance-based rather than volumetric methods STOIIP estimation is not considered critical.

Volumetrics estimates were used to confirm STOIIP in the ER-105 fault block, and these were based on depth maps from seismic interpretation that pre-dated the results from wells ER-105 and ER-106 that were drilled in December 2014. Therefore, RPS has adjusted these depth maps with formation tops from these two wells.

In the previous report by RPS, the developed wells were considered representative of the planned undeveloped wells and (excluding 1ER-102) the average EUR was 82,000 barrels. A generalised decline curve was produced to give a EUR of 82,000 barrels with a rate of decline averaging the successful developed wells. This may still be appropriate for most future wells. Test results from new well ER-105 demonstrate a reduction in production rate of 20% can be expected compared to previous wells, and the decline curve and EUR have been revised. Test results for well ER-106 show a significant reduction in expected production.

Reserves are estimated for the following:

- Revised developed Reserves for the currently producing wells ER-98, ER-99, ER-100 and ER-101. No recompletions of these wells are planned.
- New Reserves for recent developed well ER-105. No Reserves are allocated to ER-106.
- Undeveloped Reserves for four planned wells to be drilled in 2015 or early 2016 in the vicinity of ER-105 discovery well and other areas of the field.

Economics have been determined for these Reserves which allow for Government Royalty, Petrotrin Overriding Royalty (ORR), Supplemental Petroleum Tax (SPT) and Operating Costs.

The cashflows associated with the three Developed Reserves cases and the three Developed plus Undeveloped Reserves cases, on a 98.36% WI basis, are presented in Appendix 2.

RIHôs owns 98.36% of an indirect subsidiary Caribbean Rex Ltd (ñREXò) which in turn owns 100% of the South Erin Licence. RIH Reserves in South Erin as of 31st December 2014 are summarised in the following table.

Field	Gross Reserves (Mstb)[1]			RIH Net WI Reserves (Mstb)[1,2]			RIH Net Reserves Entitlement (Mstb)[1,2,3]		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
Developed	48.0	82.4	158.9	47.2	81.0	156.3	31.2	54.2	104.1
Developed plus Undeveloped	172.7	336.1	492.8	169.9	330.6	484.7	116.6	229.0	337.9

1 1P cases have negative Net Present Value at 10% discount rate (NPV10).
2 RIH owns 98.36% of REX which is 100% owner of Jasmin Oil and Gas Limited
3 RIH Net Reserves Entitlement is RIH's WI share of Reserves after the deduction of Government Royalty and Petrotrin Over-riding Royalty.

Table 1.1: Reserves as of 31st December 2014

2. INTRODUCTION

At the request of Rex International Holding Limited ("RIH" or "Company"), RPS Energy Consultants Limited ("RPS") has prepared an evaluation of selected oil Reserves and the net present values of those Reserves for South Erin Block, onshore Trinidad, as of 31st December 2014 (the "Services").

The services comprised preparation of a formal Qualified Persons Report ("QPR") report on Reserves required for statutory reporting to the Singapore Exchange Securities Trading Limited ("SGX-ST"). The report fulfils the requirements of the SGX-ST. The report has been prepared for inclusion in the RIH 2014 annual report for public viewing and access.

In preparing this report, we relied upon certain factual information and data furnished by RIH, with respect to ownership interests, production, historical costs of operation and development, product prices, agreements relating to current and future operations, sales of production, and other relevant data. The extent and character of all factual information and data supplied were relied upon by us in preparing this report and have been accepted, as represented, without independent verification. We have relied upon representations made by RIH as to the completeness and accuracy of the data provided and that no material changes in the performance of the properties has occurred nor is expected to occur, from that which was projected in this report, between the date that the data was obtained for this evaluation and the date of this report, and that no new data has come to light that may result in a material change to the evaluation of the Reserves presented in this report. As the production and reserves from existing wells is modest and the facilities are mature and of modest scale no site visit has been undertaken by RPS. Site photographs were provided by RIH which appear to be reliable and show facilities commensurate with the levels of production.

The Services have been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. However, RPS is not in a position to attest to the property title, financial interest relationships or encumbrances related to South Erin.

The evaluation reflects our informed judgement based on the PRMS 2007 Standards[1], but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and engineering data.

RPS, operating from its offices at 309 Reading Road, Henley-on-Thames, Oxon, RG9 1EL, UK, is an independent consultancy specialising in petroleum reservoir evaluation and economic analysis. The provision of professional services has been solely on a fee basis. Mr Gordon Taylor, Director, Subsurface for RPS Energy, has supervised the evaluation. He attended the University of Birmingham and graduated with a Bachelor of Science degree in Geological Sciences in 1978; and a Master of Science degree in Foundation Engineering in 1979. He is a Chartered Geologist and Chartered Engineer in the UK and a Certified Petroleum Geologist (No 5932) through the American Association of Petroleum Geologists (AAPG) with in excess of 35 years' experience in the hydrocarbon exploration and production industry including the conduct of evaluation studies relating to oil and gas fields. Additionally, Mr Gordon Taylor fulfils the following criteria for a qualified person:

a) the qualified person is not a sole practitioner;

b) the qualified person producing the report is a director of RPS Energy

c) the qualified person and RPS's partners, directors, are independent of RIH, RIH directors and substantial shareholders;

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

d) the qualified person and RPS partners and directors do not have any interest, direct or indirect, in RIH, its subsidiaries or associated companies and will not receive benefits other than remuneration paid in connection with the qualified person's report; and

e) remuneration paid to RPS in connection with the report is not dependent on the findings of this report.

Table 2.1 summarises the asset and licence details.

Asset Name/Country	RIH's effective Working Interest	Development Status	Licence Expiry Date	Area (acres)	Type of mineral, oil or gas deposit	Remarks
South Erin licence, Trinidad & Tobago	98.36%	On production	31/12/2031	1,350	Oil	In all Reserves cases, the economic limit is reached before the Licence expiry date

Table 2.1: Asset Summary & Licence

3. HISTORY OF THE PROPERTY

Prior to October 1998, The Petroleum Company of Trinidad and Tobago Limited ("Petrotrin") was the operator of the 'South Erin' block. Three wells were drilled in the south east part of the block: well TOFO.51 was drilled in 1930 and was plugged and abandoned, ER.91 was drilled in 1988 and was also abandoned, and well ER.14 was located in the block but the producing zone is outside the block (date unknown).

Ten seismic lines were acquired through or close to the block in 1976 and seven of these were reprocessed by Exxon in 1991. Three additional lines were acquired by Exxon in 1990-1991.

In October 1998, Petrotrin farmed-out the block to Jasmin Oil and Gas Limited (Jasmin). The tenure of this agreement was for five years but was extended to September 2006, with two additional renewable terms until September 2016. Under the Agreement Jasmin was obliged to undertake the minimum work programme of six wells.

Wells ER97 and ER97X were drilled in April 1999 to depths of 6,000ft and 5,300ft respectively, and encountered reservoirs but they were dry and the wells were abandoned. Jasmin drilled its third well, 1ER-98, from July to October 2006. This well tested three oil-bearing sands in Lower Forest A2 Sands and B1 Sands, and Mid Cruse Sands. Four other wells were drilled close to each other in the south east part of the block between October to December 2008. These were wells 1ER-99, 1ER-100, 1ER-101 and 1ER-102. Oil-bearing intervals were intersected in all these wells. All these wells except 1ER-102 are still on production.

REX's entitlement to production from the South Erin Block is laid down in the Farmout Agreement (Sub-Licence) of 2nd October 2013 between Petrotrin and Jasmin Oil and Gas Ltd. A licence extension for 19 years was granted in 2012 and the expiry date is now 2031.

RIH held a 64.17% interest in the Farmout Agreement (sub-licence) through its ownership of REX. Since March 2014 RIH has increased its interest in REX to 98.36%. REX owns 100% of Jasmin Oil and Gas Limited.

Development wells ER-105 and ER-106 were drilled during December 2014. Production commenced from these wells in February 2015.

4. GEOLOGICAL SETTING

4.1 Regional

4.1.1 South Erin Licence Location

RPS has put the South Erin field into regional context to try and understand some of the complexities of the geology. Many aspects of the field carry uncertainty because of the limited data control, such as trap type, and reservoir distribution and continuity.

The South Erin Block is located in the Southern Basin of south Trinidad south west of the large Palo Seco field. The South Erin field (aka as the Jasmin field) lies in the eastern part of the South Erin licence (Figure 4.1).

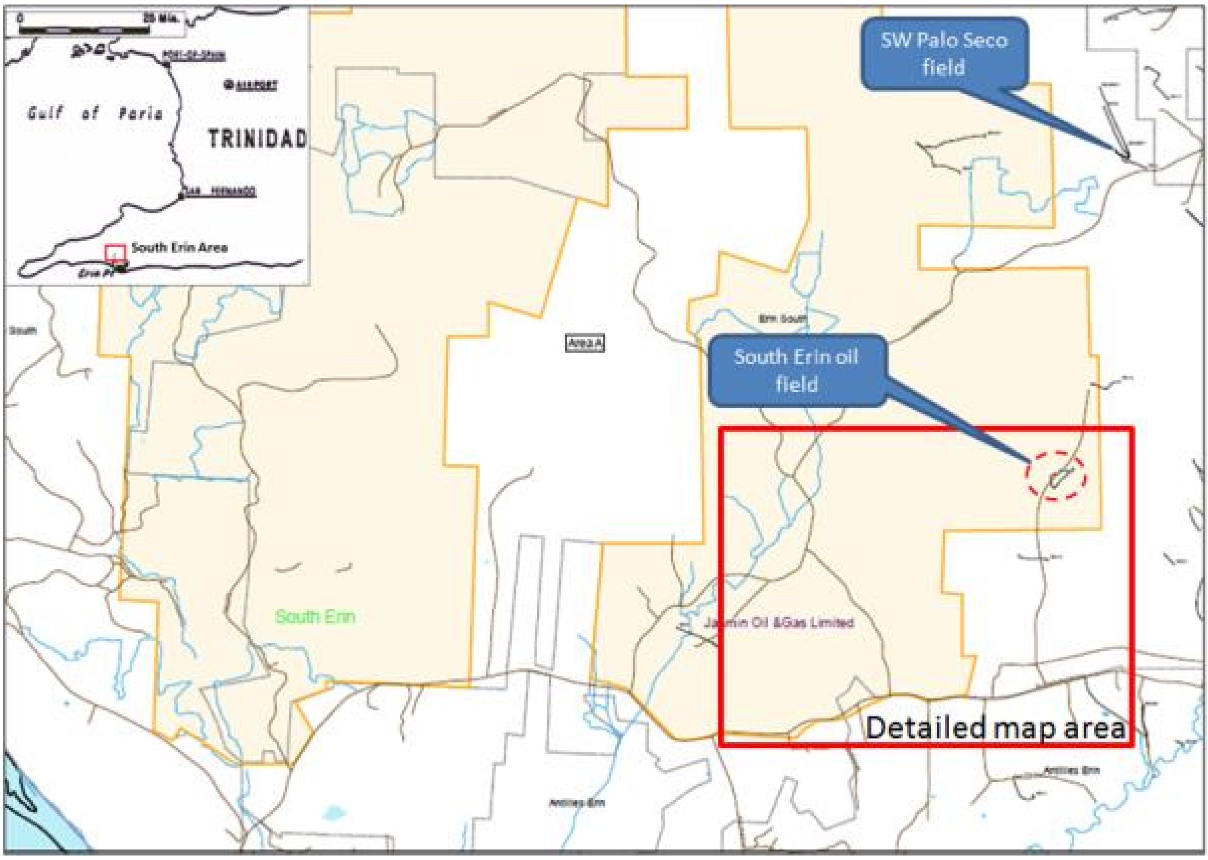

Figure 4.1: South Erin Licence

4.1.2 Palo Seco Field Complex

The Palo Seco field was discovered in 1910 and is considered to be the third largest field onshore Trinidad. Palo Seco is a complex or group of oil pools rather than a single field and comprises a series of oil fields, including Erin, Los Bajos and Grand Ravine. It covers an area of 22 km^2. According to Gluyas & Swarbrick[2], Palo Seco has estimated STOIIP of 1,691 MM stb. The main producing reservoirs are Pliocene and Miocene sandstones, including the deltaic Lower Forest and Cruse sands. These formations are the oil-bearing sands at South Erin, which is located west of the main Palo Seco field (Figure 4.2). The Erin extension to Palo Seco was discovered in 1963.

[2] *'Case History: Trinidadian Oilfields'. In: Petroleum Geoscience by Gluyas and Swarbrick, Wiley & Son, 2013*

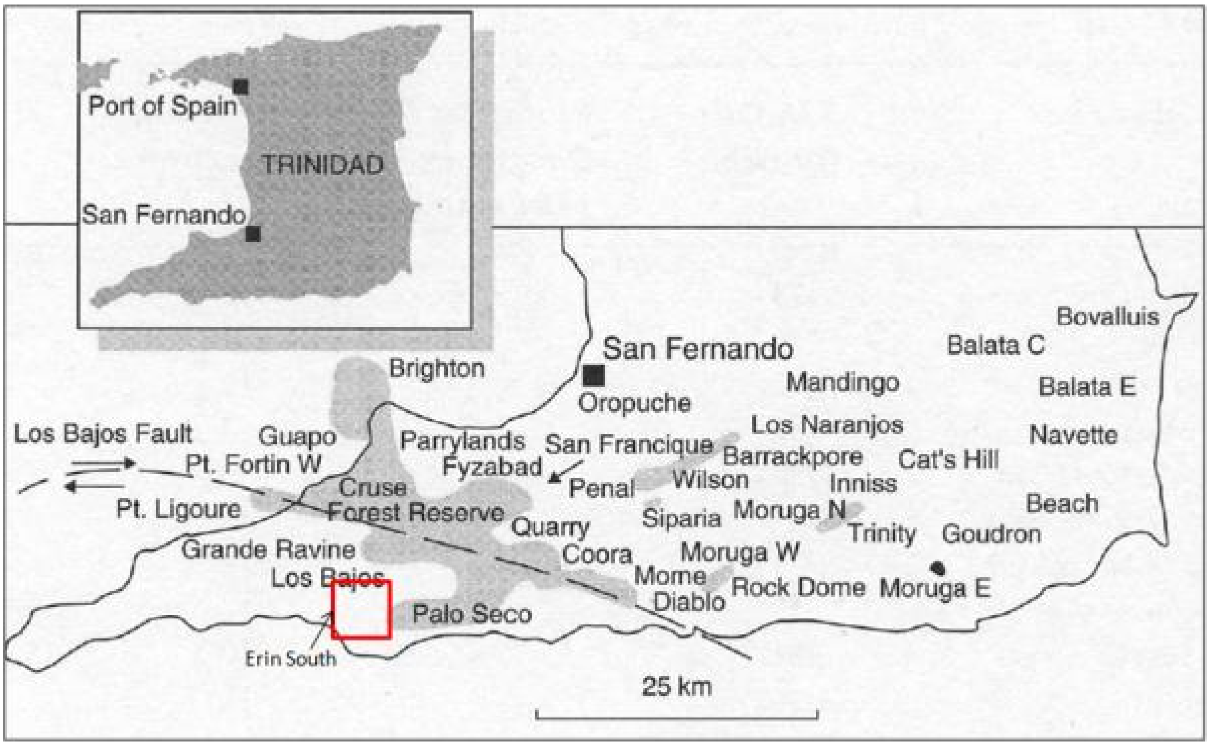

Figure 4.2: South Erin Licence & Other Oil Fields

4.1.3 Structure

Regional structural elements of the south west part Southern Basin are shown in Figure 4.3. The Palo Seco field is located in the southern limb of the Siparia-Erin Syncline. It is proposed by several authors on the area that there is a significant stratigraphic element to trapping in the Palo Seco field and Woodhouse[3] states that this is the primary trap type.

The basin is affected by numerous faults. Normal, reverse, thrust and strike-slip faults are reported from the basin and can be large scale or sub-seismic in size. The combination of the faulting with the lenticular nature of the reservoir sands and rapid lateral facies changes creates a complex geology.

Part of a 3D seismic survey extends into the South Erin licence and was purchased by RIH in early 2014. Two depth maps from the interpretation of this data by Aggo Geoconcepts were provided to RPS in March 2015, although they pre-date the drilling of wells ER-105 and ER-106. These maps show a significantly different fault pattern to previous maps that were provided for the earlier RPS report when depth mapping and fault positions were based almost entirely on well results. The current mapping shows a revised fault pattern but still a regional bed dip to the north-west.

[3] *Woodhouse. P.R. The Petroleum Geology of Trinidad and Tobago. U.S. Geological Survey Open-File Report 81-660*

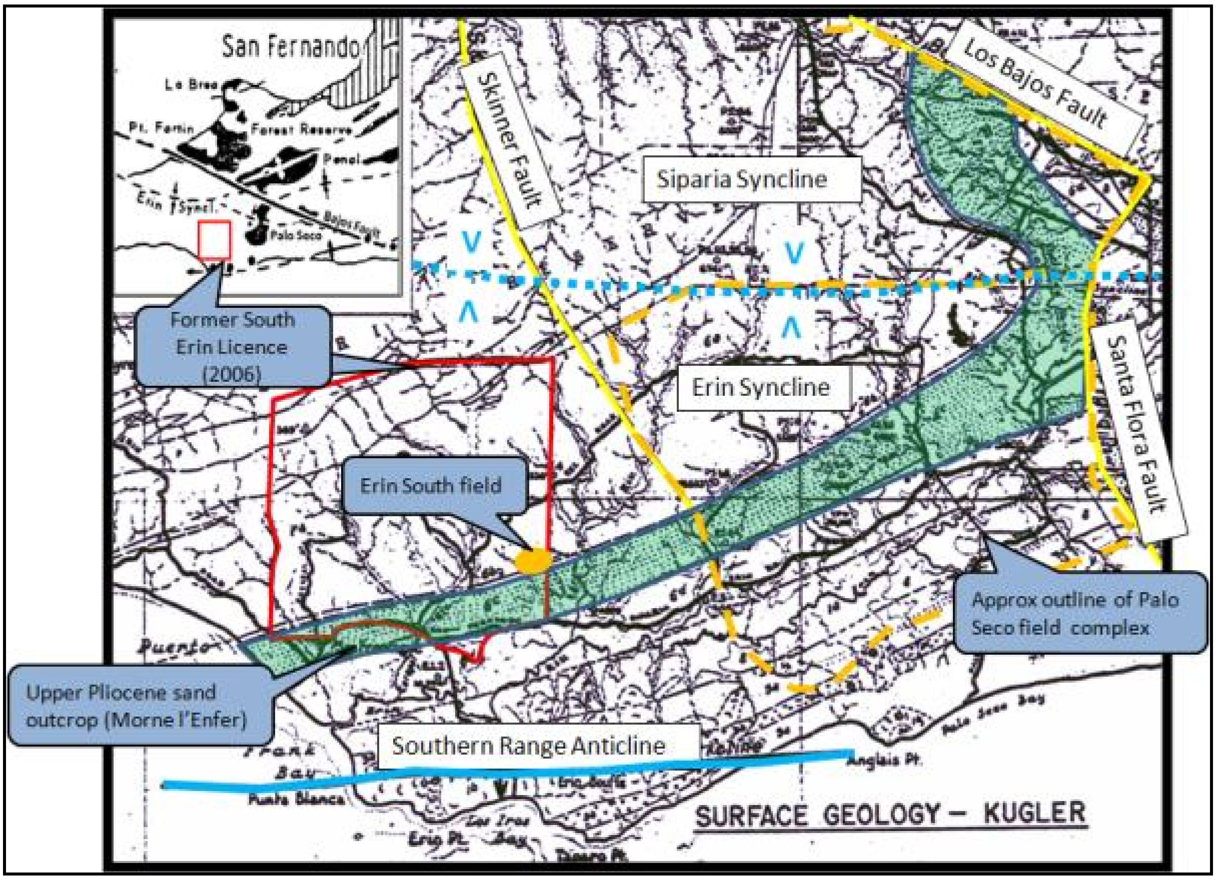

Figure 4.3: Southern Basin Regional Structure

4.1.4 Basin Stratigraphy and Reservoirs

The oil bearing reservoirs at South Erin are the Pliocene Lower Forest and Mid Cruse Sandstones (Figure 4.4). Lower Forest Fm comprises lenticular delta-top sandstones and this overlies more extensive delta-front turbidites of the Cruse Fm.

Over 90 percent of cumulative historical onshore oil production from Trinidad has come from sandstones of the Pliocene Lower Forest and Cruse formations, and Moruga Group sands in the south-east. Both the Cruse and Lower Forest sandstones were deposited by rivers from the east and south-east, and the sands thin towards the west. Although not specifically documented, it is proposed that the dominant Pliocene depositional system was a deep marine basin during Early Pliocene-Late Miocene Cruse deposition with turbidite sands deposited from the east and south east. At Palo Seco, Cruse Fm depositional setting is interpreted by Hudson *et al*[4] to range from basin floor and slope to marginal marine and inner neritic.

During Mid Pliocene Lower Forest deltaic progradation was towards the west. Delta-top sands were deposited in the Lower Forest Fm and may comprise distributary and fluvial channel sands, and channel mouth bar sandstones. A geological model is needed at South Erin in order to optimise field development, and the interpretation of the 3D seismic data will be an important step in this process. Stratigraphic pinch-out of sandstones is evident from well data at South Erin, and considered a likely trapping mechanism.

[4] *Hudson. D. et al, 1993.Applied sequence stratigraphy analysis of well logs, Cruse Fm, Palo Seco field. Society of Petroleum Engineers (Trinidad and Tobago section) meeting held in June 1993.*

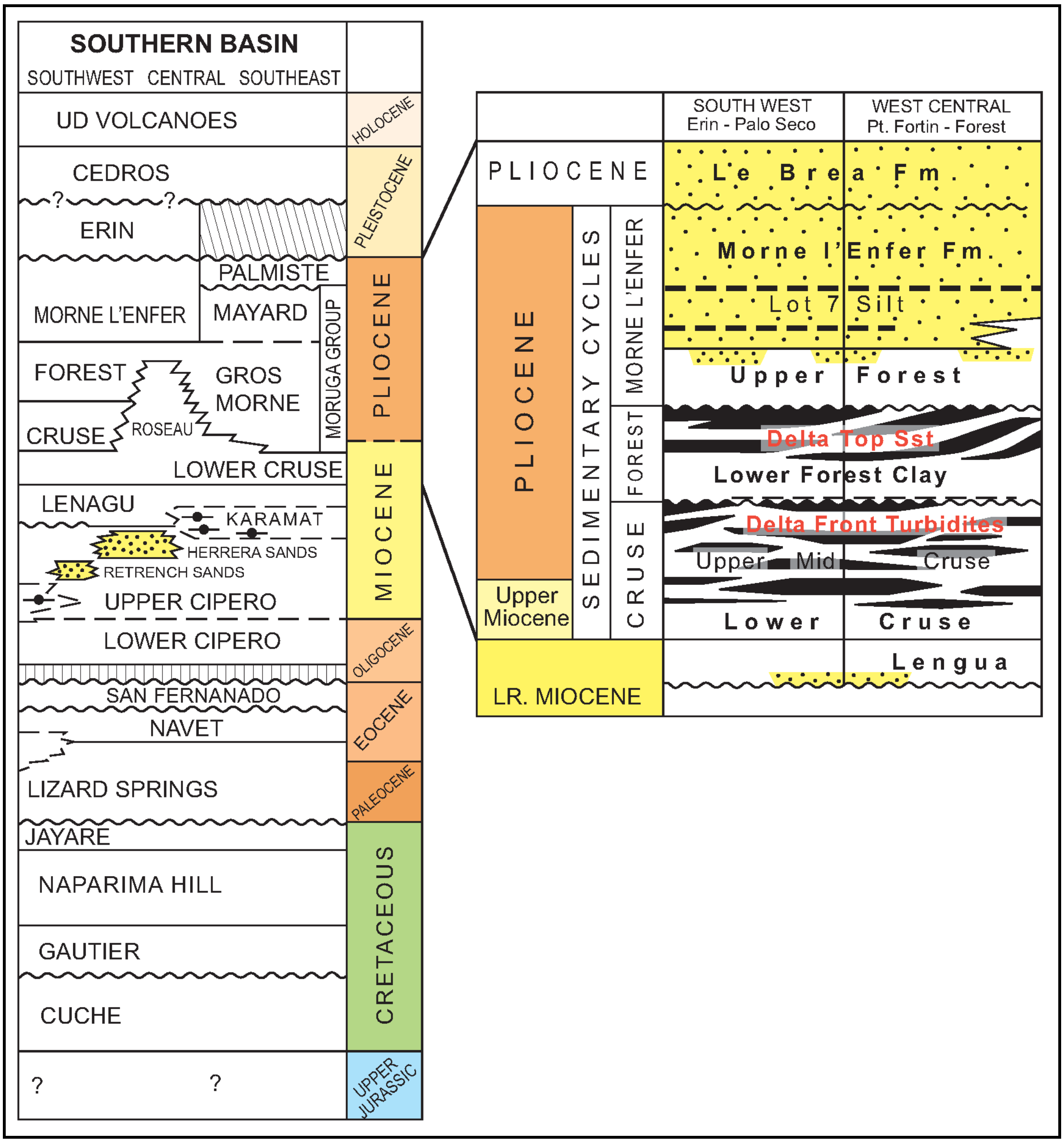

Figure 4.4: Southern Basin Stratigraphy

5. TECHNICAL DATA

A technical dataset has been provided by RIH for this report.

5.1 Geological

For the year-end 2013 report (issued in March 2014), a geoscience dataset included a 2009 report by M.L. Geotechnical Consultants Ltd[5] which contained depth structure maps and gross sand and ónet oil sandôisopach maps. These maps were based almost entirely on log data from five wells (1ER-98, 1ER-99, 1ER-100, 1ER-101 & 1ER-102) plus one or two 2D seismic lines. As a result the geological model for the field was highly speculative.

Also in the year-end 2013 RPS report were proposed locations for four new wells to be drilled in 2014. These planned wells were CH8 and CG8 to be located in the east area, close to the current producers, and CG3 and CG4 that were proposed further to the west, approximately 200-250 m west-south-west of the subsurface TD location of well 1ER-100. Of these planned wells, only CG8 (ER-106) has been drilled along with a second well, CH6 (ER-105), which was located north west of the main field area. These wells were drilled in December 2014.

Geological data provided for this current report includes new depth maps at Top Forest and Top Cruse formations based on a 3D seismic interpretation for RIH by consultants Aggo Geoconcepts, although these were not updated with formation tops from the two new wells. RPS has revised these depth maps with the new well tops from wells CH6 (ER-105) and CG8 (ER-106) - see Figure 5.1 and Figure 5.2.

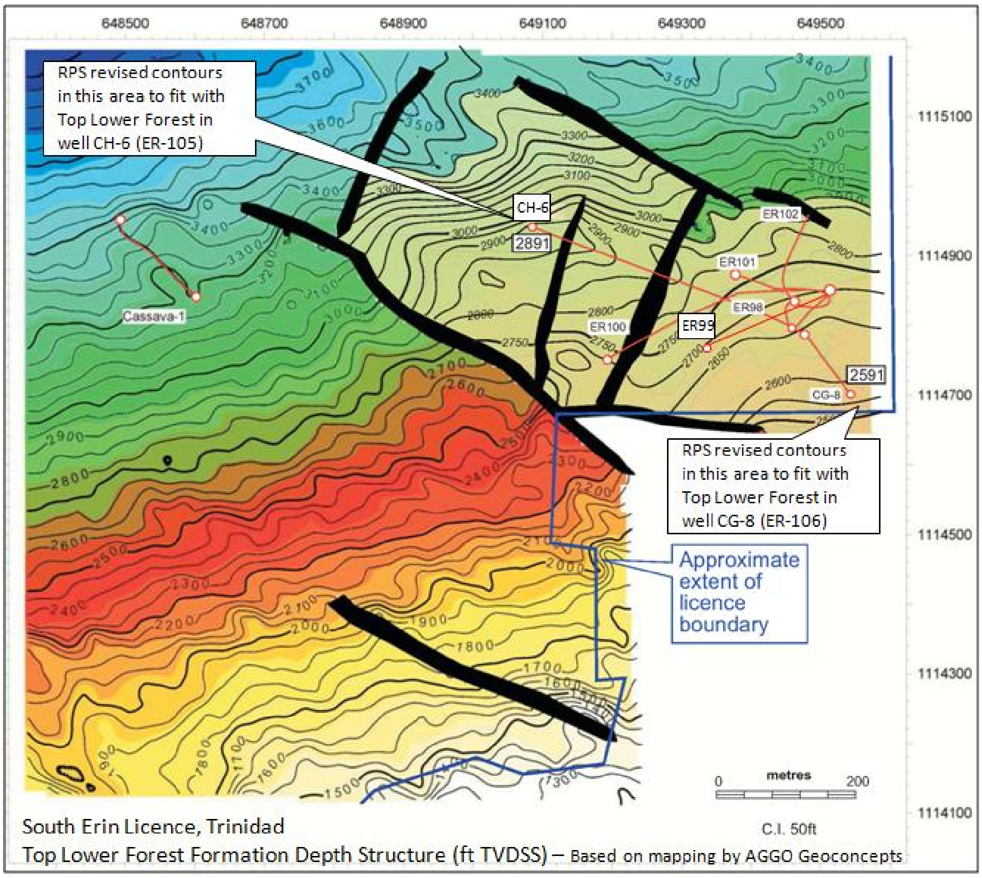

Figure 5.1: Top Lower Forest Fm Depth Structure

[5]*Updated Geological Review of Jasmin's Farm-out – South Erin Block 1ER98 Area by M.L. Geotechnical Consultants limited. November 2009.*

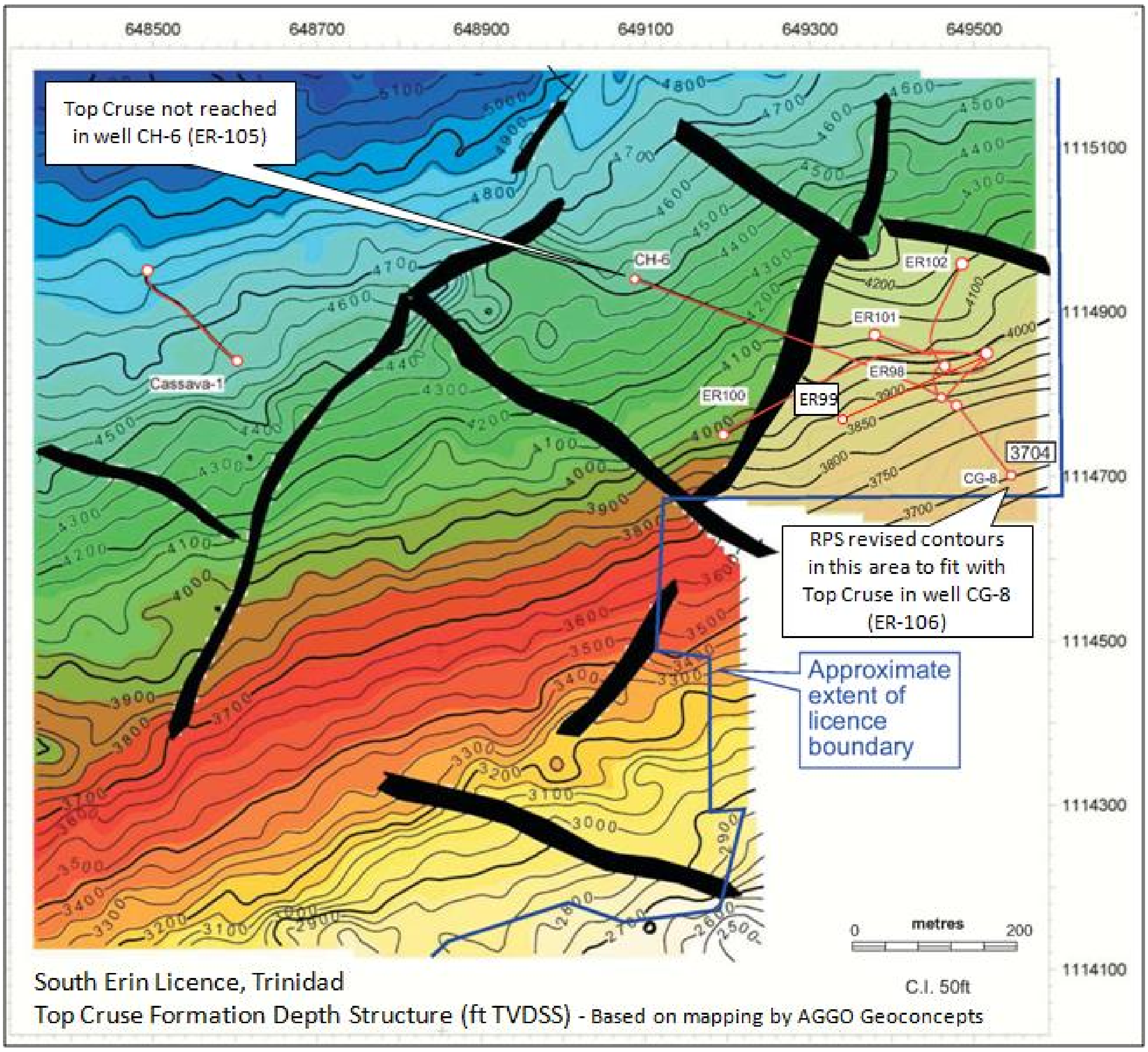

Figure 5.2: Top Cruse Fm Depth Structure

5.2 Wells

For the year-end 2013 report (issued in March 2014), digital well data were provided for the five wells drilled at that time and also petrophysical evaluation reports with CPI logs by Schlumberger for all wells except 1ER-98. For the current report, full suites of wireline logs were provided for recent wells ER-105 (CH-6) and ER-106 (CG-8) plus petrophysical evaluation CPI displays and a digital summary of interpretation results by RIH's consultants FRAM Exploration.

RPS has undertaken a review of the data and petrophysical interpretation and found it to be reasonable. Well locations and trajectories are shown in Figure 5.1 and Figure 5.2. No deviation surveys were provided for these highly deviated wells.

5.3 Seismic

For the 2014 RPS report, digital and scan format data were provided for only one 2D seismic line, the west-south-west to east-north-east trending line, 76-27, that passed near the field but it was of limited value.

Part of a 3D seismic survey was purchased by RIH across the South Erin area in early 2014. This was provided to RPS in early February 2014 and several lines were viewed across key faults. The 3D data have been interpreted by Aggo Geoconcepts on behalf of RIH but this has not been provided to RPS except for a few depth maps. The 3D data and Aggo

Geoconceptôs interpretation have not been evaluated by RPS as RPS were only engaged to undertake this project by RIH shortly before the final report was due to be submitted. The RPS remit was to update the previous year-end Reserves report based on the 2014 production history, the new wells drilled and tested in 2014, and updated oil price and capex/opex estimates as insufficient time had been allowed for a review of the 3D seismic.

5.4 Production Data

Production history data have been provided for all producing wells up to 5^{th} March 2015. This includes production from new well ER-105 from the 31^{st} January 2015 and from ER-106 since the 5^{th} February 2015.

6. IN-PLACE VOLUMETRICS

6.1 Traps and Reservoirs

A general west to east correlation of the pre-2014 wells across the field shows the stratigraphy and main reservoirs of the Lower Forest Fm. at South Erin (Figure 6.1). The deeper Cruse Fm. was drilled only by well ER-98, which encountered oil-bearing sand in Middle Cruse.

The new depth map at Top Lower Forest (Figure 5.1) does not resolve the question of the trap type in the main part of the field for the Lower Forest reservoirs, of which the A2 and B1 sands are the most prolific producing intervals. The structural map shows the updip direction to be towards the south-east but structural closure is not demonstrated. One of the new wells, CG-8 (ER-106) was drilled in this updip corner of the licence but did not encounter obvious A2 or B1 Lower Forest sands, which were the primary reservoir objectives. Absence of these sands is unexplained by RIH but could either be caused by being faulted out, although no fault in the area is shown on the maps, or the sands may have óshaled-outô towards the south-east. The absence of these sands might explain the trapping mechanism for the A2 and B1 sands in the field by stratigraphic pinch-out towards the south-east. The uncertainty concerning the position and type of the trap and extent of the main producing A2 and B1 sand reservoirs demonstrate that estimations of technical reserves are more accurate by well performance rather than volumetric calculations.

The new 3D seismic interpretation seems to confirm that a fault separates the main field from well ER-102 to the north east, where sands A2 and B1 are not developed. Also, well ER-100 appears to be confirmed to cross a fault to the west, and the A2 sand in this well is either faulted out or undeveloped but the B1 sand was present and oil-bearing (Figure 6.1). The Top Lower Forest Depth map (Figure 5.1) appears to confirm that the oil-bearing B1 sand lies west of this fault in a separate fault block but this has not been validated by RPS.

The new seismic interpretation shows no mapped faulting in the central part of the field close to wells ER-98, ER-99 and ER-101 but stratigraphic variations are recognised between the wells that appear to cause stratigraphic trapping.

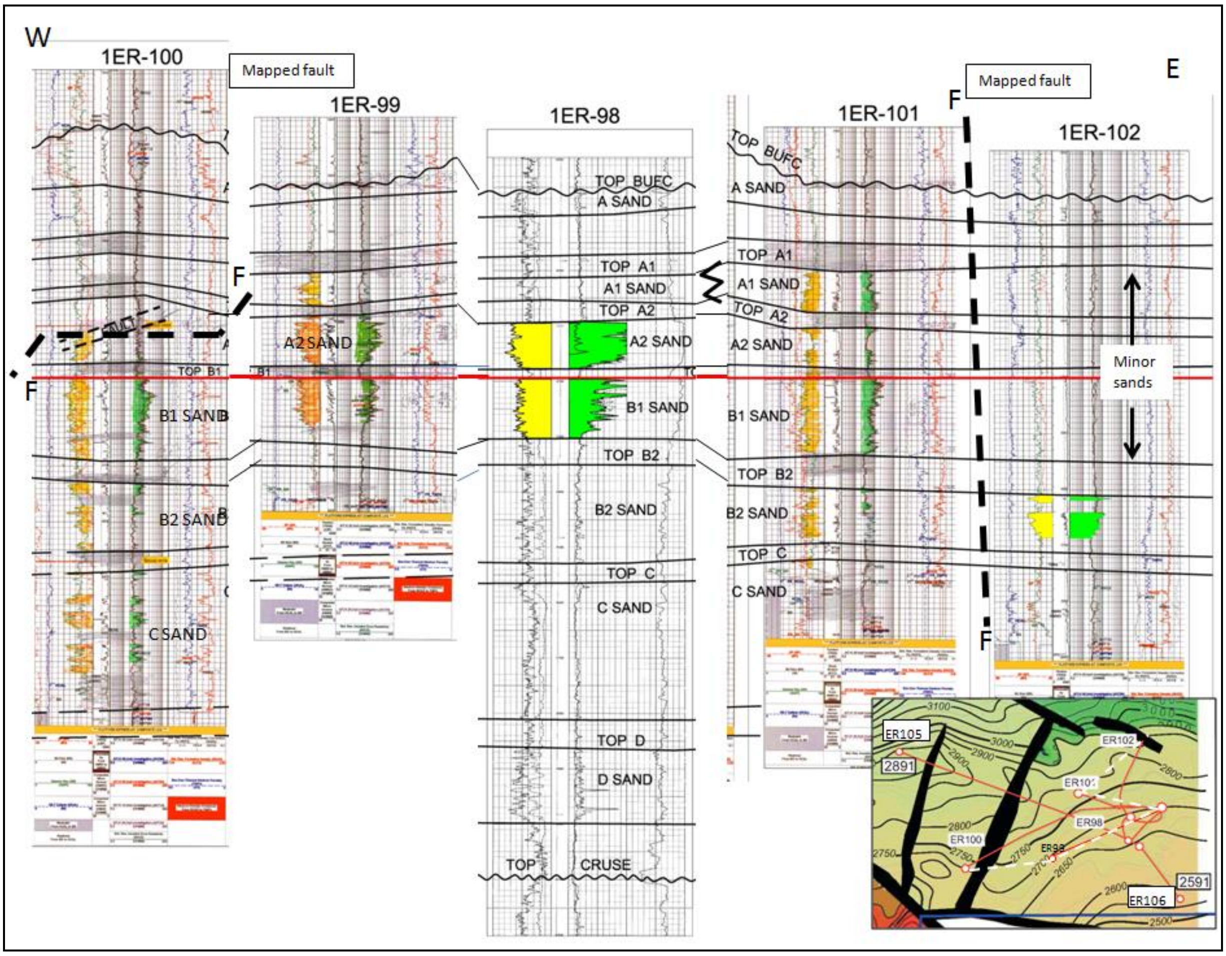

Figure 6.1: West-East Well Correlation at South Erin Field

6.2 Petrophysical Review

RPS has reviewed the main reservoirs in the field. For the year-end 2013 report, RPS carried out an independent petrophysical evaluation of well 1ER100. A comparison of petrophysical results for the B1 sand in this well by both RPS and Schlumberger showed very close agreement in estimations of net pay thickness, porosity and water saturation. As all the wells (except ER-98) were evaluated by Schlumberger, this gave confidence in the accuracy of the petrophysical results provided.

For this report, RPS has petrophysical data for wells ER-105 and ER-106 that comprises digital raw logs and interpreted results data. A review of the interpretations by consultants FRAM Exploration has been carried out and been found to be acceptable. A petrophysical CPI log for well ER-105 is shown in (Figure 6.2) where net oil pay intervals were found in A2 and B1 sands. These were the main reservoir objectives for the well and the net thickness and depth results came in close to prognosis.

By contrast, the results of well CG-8 (ER-106) in the south of the field were quite different to the prognosis. The main objectives were Lower Forest ‘A’ & ‘B’ sands and the Middle Cruse sands. The A2 and B1 sands were very poorly developed in the well and, if present at all, appear to comprise only sand stringers with negligible net pay. Relatively thin net oil pays were encountered in the Lower Forest B2 and C sands, and the Upper Cruse sands (Figure 6.3).

Petrophysical results summaries from FRAM Exploration's analysis for each zone are posted on the CPI logs. RPS has reviewed these results and considers them acceptable.

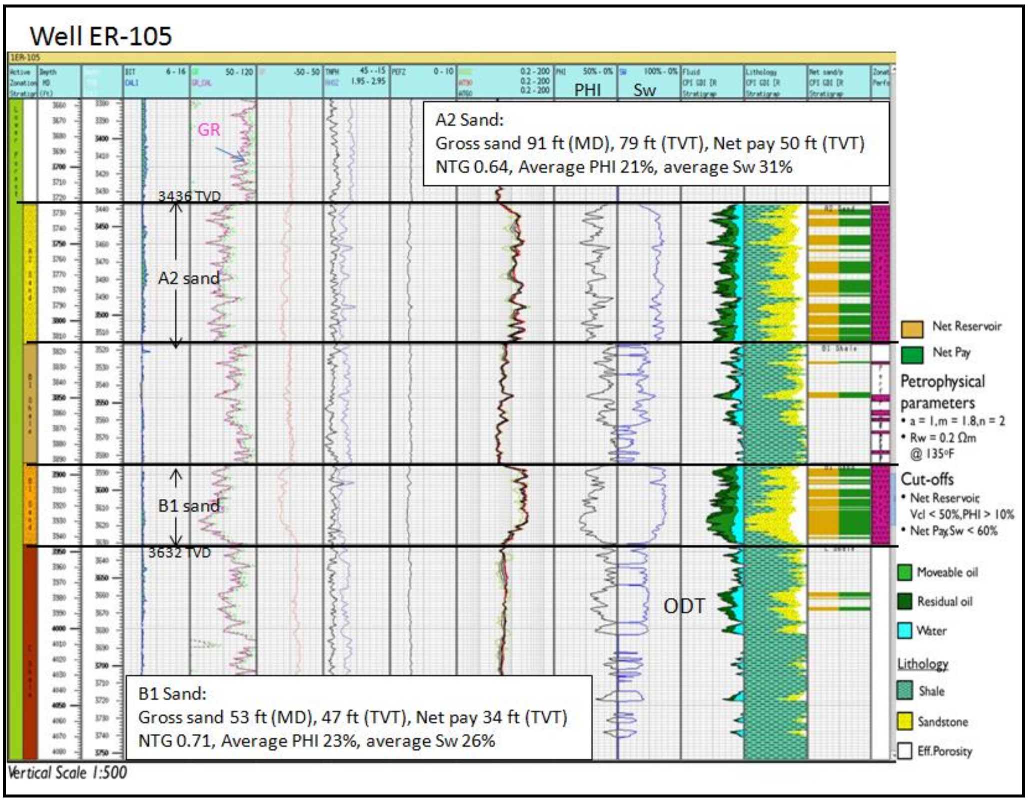

Figure 6.2: Well ER-105 Petrophysical CPI Log

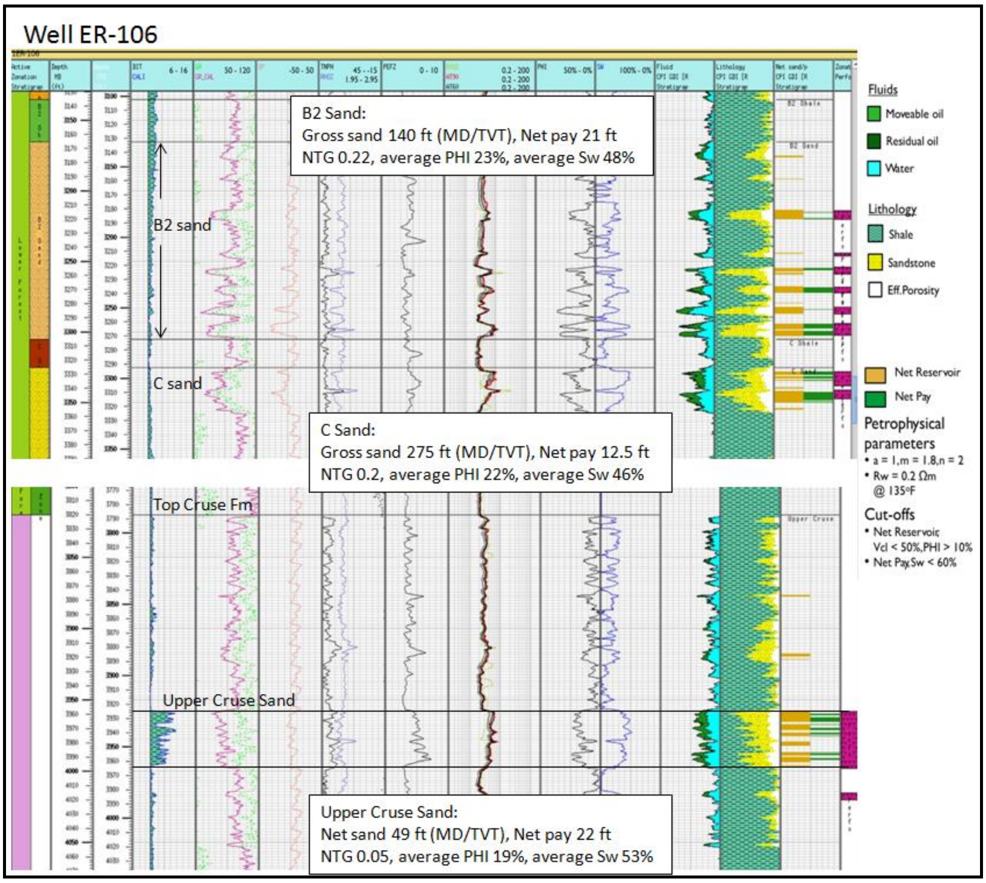

Figure 6.3: Well ER-106 Petrophysical CPI Log

6.3 In-Place Volumetrics

Due to the geological uncertainty away from the wells in the field concerning reservoir and pay distributions, and the extent of closure, RPSôTechnical Reserve estimations are based on production histories rather than volumetric calculations of oil in-place and the application of a recovery factor. But a quick volumetric estimation was carried out for the area around well ER-105 to ascertain whether there was sufficient oil in-place in the pay intervals to provide the Reserves determined from decline curve analysis or analogue production performances for ER-105 and two other future development wells.

6.3.1 Well ER-105

A volumetric estimation of oil in-place was carried out for the fault compartment drilled by well ER-105, which discovered oil pay zones in the A2 and B1 sands (Figure 6.2). The petrophysical CPI log for ER-105 shows oil saturation in the A2 and B1 sands over a vertical thickness of at least 200 ft, and this assumes a single oil column although no pressure data were available to verify this. Based on this column thickness a closure extent for the A2 sand can be assumed to be at least 200 ft down-dip from well ER-105. The depth map is at Top Lower Forest but is used as a proxy for structure at top A2 sand, which is 546 ft deeper. A P50 closure extent is shown at approximately 200 ft down-dip from the well at 3,100 ft (Figure 6.4).

The underlying B1 sand at ER-105 has at least 80 ft oil column shown on the CPI log down to thin oil bearing sands, which indicate an oil-down-to (ODT).

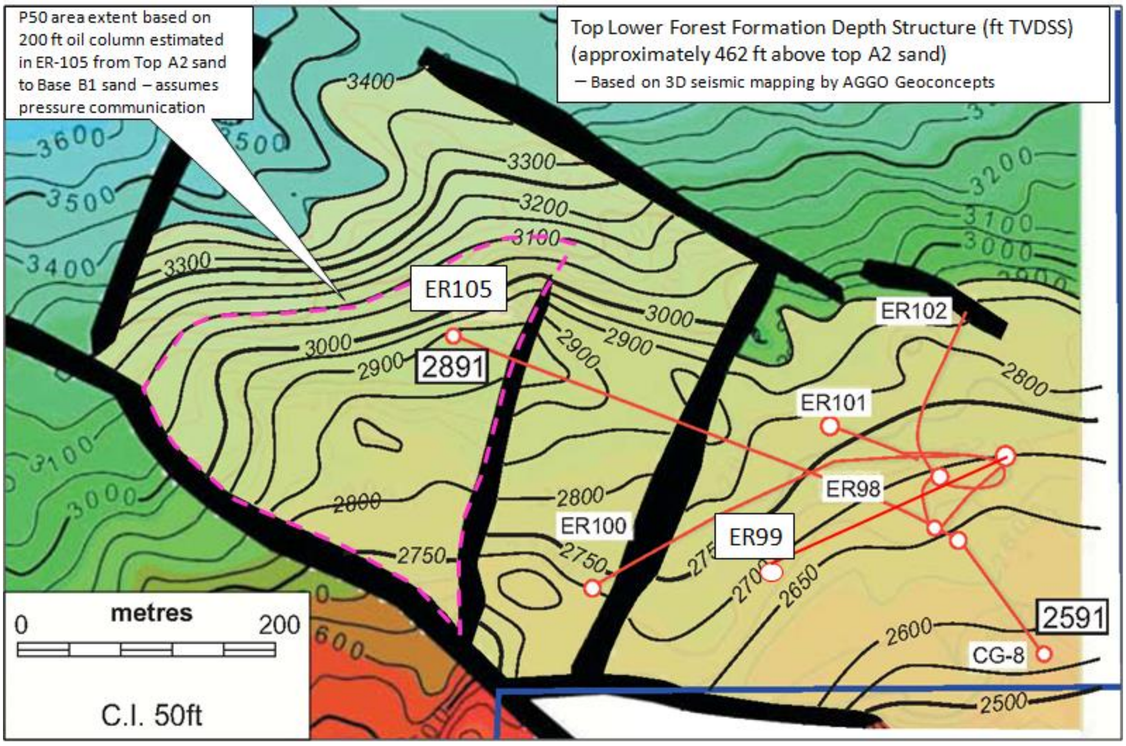

Figure 6.4: Top Lwr Forest Depth showing ER-105 Fault Sector

Ranges for gross sand thickness and petrophysical properties for these two reservoirs are taken from the ER-105 well analysis, and probabilistic calculations of oil-in-place have been carried out by RPS for the ER-105 fault compartment area. Certain assumptions have been made for these estimations, these are:

i) that the mapping is accurate at top reservoir level (it is based on 3D seismic at Top Lower Forest but RPS has not seen the interpretation);

ii) that the oil column is a single column and not multiple columns separated by shale seals; and

iii) that sands are present throughout the fault block.

It is evident from other wells in the field that there can be significant variation in reservoir distribution and quality, consequently appraisal drilling in this area carries geological risk. Risk has not been quantified by RPS because it has not evaluated the 3D seismic data and interpretation and, therefore, cannot estimate the level of geological risk for future wells in this area.

Parameters used for volumetric calculations for sands A2 and B1 and the oil-in-place estimations are set out in Table 6.1 & Table 6.2.

Parameter	Unit	P90	P50	P10
Closure contour	ft	3000	3100	3200
Closure area	acres	8	11.5	14.4
Gross Sand	ft	64	80	100
NTG	%	58	64	70
Porosity	%	19	21	23
Sw	%	40	31	22
FVF	vol/vol	1.2	1.15	1.1
STOIIP	**Mstb**	**320**	**500**	**760**

Table 6.1: Parameters & STOIIP for A2 Sand in the ER-105 Fault Block

Parameter	Unit	P90	P50	P10
Closure contour	ft	2980	3050	3120
Closure area	acres	7.5	10	12
Gross Sand	ft	37	47	60
NTG	%	55	65	75
Porosity	%	21	23	25
Sw	%	40	26	12
FVF	vol/vol	1.2	1.15	1.1
STOIIP	**Mstb**	**200**	**310**	**480**

Table 6.2: Parameters & STOIIP for B1 Sand in the ER-105 Fault Block

Total STOIIP estimated in the ER-105 fault block for the two reservoirs and consolidated probabilistically are:

P90 ï 600 Mstb, P50 ï 833 Mstb, P10 ï 1,150 Mstb

6.3.2 Well ER-106

No estimation has been made of STOIIP in the area of well ER-106 in the Lower Forest B2 and C sands or the Upper Cruse sands found in this well.

7. Reserves Estimation

7.1 Developed Reserves

Using the production history provided, production profiles have been created for each of the established developed wells. The maturity of the assets and provision of complete historical production data has allowed Decline Curve Analysis of these profiles to be used to give estimated recoverable volumes for each well for a P90, P50 and P10 case. For the P90 case exponential decline was assumed, for the P50 hyperbolic decline and for the P10 harmonic decline. The results of this analysis are presented in Table 7.1 below.

Wells	**Oil Volume (Barrels)**						
	Produced Volume [1]	**Expected Ultimate Recoverable (EUR) Volume [2]**			**Remaining Recoverable Volume [2]**		
		P90	**P50**	**P10**	**P90**	**P50**	**P10**
1ER-98	114,551	119,150	122,280	127,181	4,599	7,729	12,630
1ER-99	62,290	68,536	72,547	78,761	6,246	10,257	16,471
1ER-100	65,762	84,788	99,945	109,271	19,026	34,550	52,332
1ER-101	34,598	42,616	46,414	52,138	8,018	11,816	17,540
1ER-102	1,081	1,081	1,081	1,081	0	0	0
TOTAL [3]	278,282	316,171	342,267	368,432	37,889	64,352	98,974

Note:
1. *Produced Volume as of end 2014*
2. *These recoverable volumes have not had an economic cut-off applied*
3. *Total is the arithmetic sum of individual wells.*

Table 7.1: Results of Decline Curve Analysis on the Developed Wells (stb)

The established developed wells are considered representative of recently drilled wells for which limited production data is available. Therefore the results of the decline curve analysis can be used to predict profiles for new development wells. For the four successful developed wells (1ER-102 is excluded) the average EUR is approximately 82,000 barrels. A generalised decline curve has been produced that gives an EUR of 82,000 barrels with a rate of decline averaging the successful developed wells. This decline curve has been applied as the most likely profile for new wells (Figure 7.1).

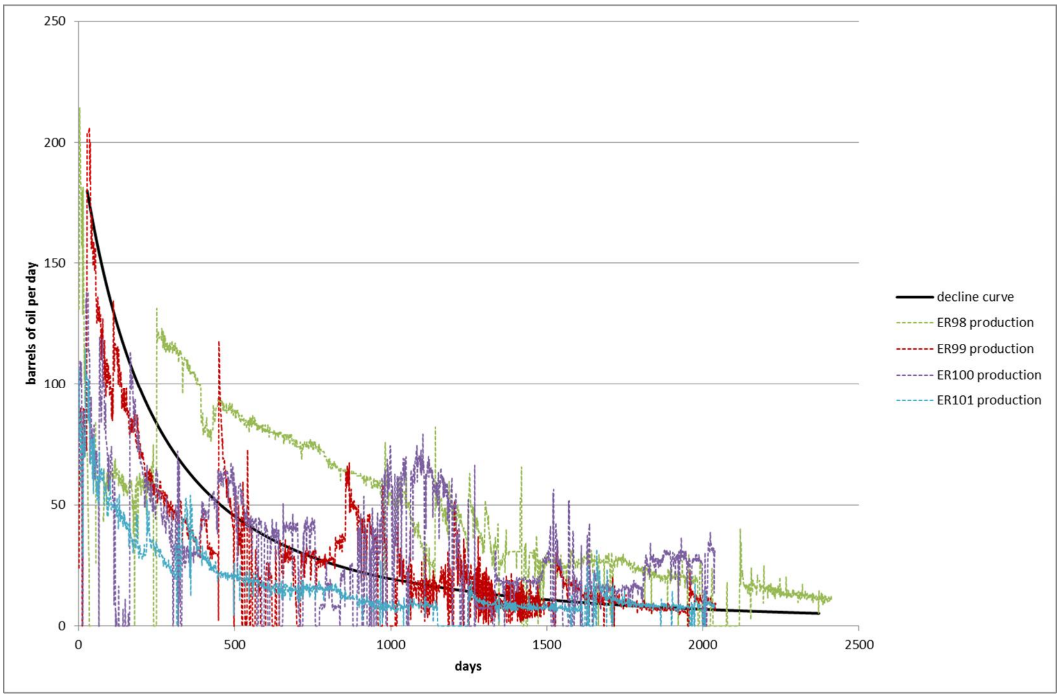

Figure 7.1: A Comparison of the Generalised Decline Curve with Historical Production Data

RPS has investigated the wells in a nearby development on onshore Trinidad which are also producing from the Lower Forest sands. These wells had similar initial production rates to the South Erin wells but the reported EUR per well is lower with a P50 prediction of 38,000 barrels.

The wells investigated have been producing for a similar time period as the South Erin wells. Therefore it is reasonable to compare the cumulative oil production data to give a better idea of how the two fields correspond. This comparison is presented in Figure 7.2. The analysis show similar cumulative oil production from the wells in the two fields with the successful wells in South Erin fitting in the range given by the twelve analogous wells.

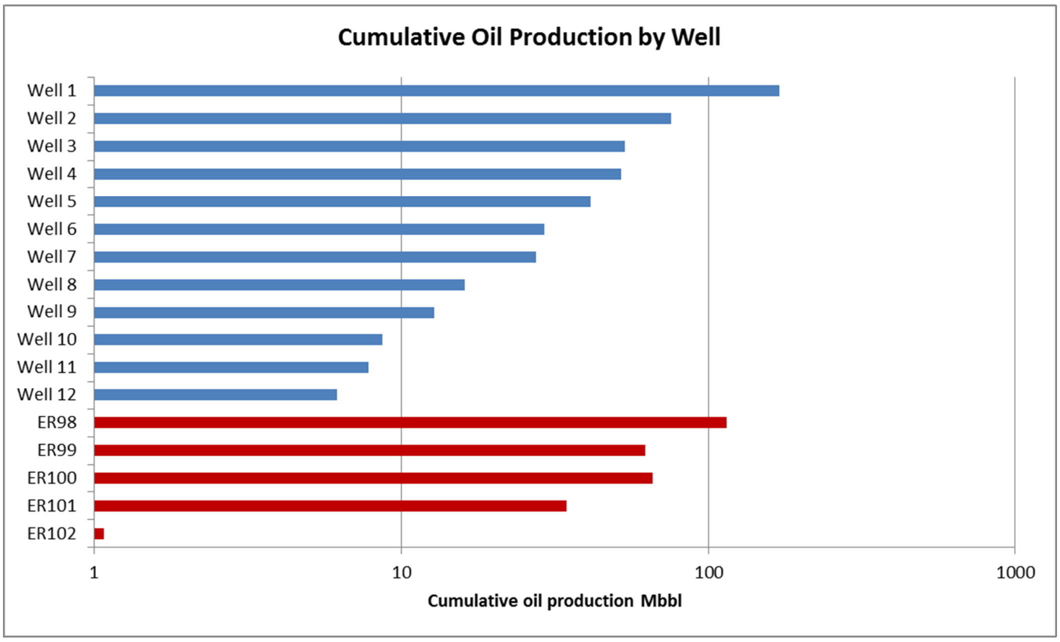

Figure 7.2: Comparison of the Cumulative Oil Production from South Erin and Offset Wells

RPS have been informed of three recently drilled wells: ER-105 (formerly CH-6), ER-106 (formerly CG-8) and Cassava-1. The exploration well Cassava-1, outside of the main producing area, did not find commercial quantities of hydrocarbons and so will not be developed.

The ER-106 well has been tested in the Upper Cruse sands with disappointing results. It is now intended to be recompleted soon in the Lower Forest C and B2 sands, however, due to poor log results and a lack of suitable analogues no reserves have been assigned to this well.

The ER-105 well has been successfully tested in the Lower Forest B1 and A2 sands. Its production is expected to follow the shape of the Generalised Decline Curve given in Figure 7.1. Since the initial tests on the well showed an initial production rate ~20% lower than that of the Generalised Decline Curve, the profile for ER-105 has been produced by applying a 20% discount factor to the Generalised Decline Curve. Due to the high level of uncertainty in the performance of this well the P90 and P10 cases are calculated as +/-40% of the P50 discounted Generalised Decline Curve. Estimated annual production levels for ER-105 are shown in Table 7.2. Production profiles for all developed wells are given in Table 7.3.

	WELL ER-105 (Barrels)		
	P90	**P50**	**P10**
2015	23,836	28,376	39,727
2016	10,532	12,539	17,554
2017	5,524	6,576	9,207
2018	3,409	4,059	5,682
2019	2,314	2,754	3,856
2020	1,677	1,997	2,795
2021	1,265	1,506	2,109
2022	991	1,180	1,652
2023	797	949	1,329
2024	657	782	1,095
2025	548	652	913
2026	465	553	775
2027	305	428	255
2028	0	0	0
2029	0	0	0
2030	0	0	0
2031	0	0	0
TOTAL	**52,016**	**61,923**	**86,693**

Table 7.2: Production Profile for well ER-105

	DEVELOPED (Barrels)		
	P90	P50	P10
2006	4,016	4,016	4,016
2007	26,569	26,569	26,569
2008	29,831	29,831	29,831
2009	67,723	67,723	67,723
2010	54,848	54,848	54,848
2011	32,483	32,483	32,483
2012	27,959	27,959	27,959
2013	17,382	17,382	17,382
2014	17,467	17,467	17,467
2015	30,523	42,482	54,221
2016	17,504	23,923	29,866
2017	10,927	15,972	19,917
2018	6,338	11,951	15,164
2019	4,054	8,957	12,364
2020	2,133	6,250	10,510
2021	0	4,730	9,169
2022	0	2,879	7,710
2023	0	1,673	6,341
2024	0	1,486	4,332
2025	0	1,329	2,931
2026	0	1,196	2,142
2027	0	373	2,018
2028	0	0	1,908
2029	0	0	1,810
2030	0	0	1,721
2031	0	0	1,372
Remaining	**71,479**	**123,201**	**183,496**
Notes: 1. Licence expiry October 2031. 2. Developed wells are ER-98, 99, 100, 101, 102 & 105.			

Table 7.3: Developed Production Profile

7.2 Undeveloped Reserves

RIH has confirmed its intention to drill four further development wells within the South Erin licence up to late 2016. This will include two wells in the ER-105 fault compartment in the same A2 and B1 pay zones as ER-105 is expected to be completed during late 2015 or early 2016. Due to the planned similarities with the existing ER-105 well the expected profiles for these developments are the same as the predicted profile for ER-105; that is a 20% discount on the Generalised Decline Curve for the P50 case and +/- 40% of this for the P90 and P10 cases. These two wells are estimated to come on production in January 2016.

Two further development wells are planned within the field area with production estimated to commence in January 2017. Production profiles for these four undeveloped wells are shown in Table 7.4.

Production profiles for developed and undeveloped wells are given in Table 7.5. Total remaining reserves are also given in this table.

An estimation of oil in-place for the ER-105 fault compartment in the A2 and B1 sands was carried out by RPS, and P50 case STOIIP was 833,000 stb (see Table 6.1 & Table 6.2). Estimated P50 case EUR in this fault block for ER-105 (Table 7.2) plus two undeveloped wells (Table 7.4) totals 179,503 stb. This equates to an ultimate recovery factor in this fault segment of 21%. The two other development wells will target other areas of the field.

	UNDEVELOPED (Barrels)		
	P90	P50	P10
2015	0	0	0
2016	35,833	59,722	83,611
2017	49,927	83,211	116,496
2018	21,642	36,070	50,498
2019	12,252	20,420	28,587
2020	7,922	13,204	18,486
2021	4,911	9,249	12,949
2022	1,692	6,834	9,567
2023	0	4,699	7,371
2024	0	1,750	5,861
2025	0	0	3,503
2026	0	0	884
2027	0	0	0
2028	0	0	0
2029	0	0	0
2030	0	0	0
2031	0	0	0
Remaining	**134,179**	**235,159**	**337,813**
Notes: 1. Licence expiry October 2031. 2. Four undeveloped wells. 3. Assumed start of production 1/1/2016.			

Table 7.4: Undeveloped Production Profile

	DEVELOPED+UNDEVELOPED (Barrels)		
	P90	P50	P10
2015	30,523	42,482	54,221
2016	53,337	83,645	113,476
2017	60,854	99,183	136,413
2018	27,980	48,021	65,662
2019	16,305	29,376	40,952
2020	10,055	19,454	28,996
2021	4,911	13,979	22,118
2022	1,692	9,713	17,277
2023	0	6,372	13,712
2024	0	3,236	10,194
2025	0	1,329	6,434
2026	0	1,196	3,026
2027	0	373	2,018
2028	0	0	1,908
2029	0	0	1,810
2030	0	0	1,721
2031	0	0	1,372
Remaining	**205,658**	**358,360**	**521,309**

Table 7.5: Developed + Undeveloped Production Profile

The analysis has shown the total EUR (based on developed and undeveloped wells) to be 483,940 barrels in the P90 case, 636,642 barrels in the P50 case and 799,590 barrels in the P10 case.

A production profile is given in Figure 7.3 for the developed + undeveloped P90, P50 and P10 forecasts for the South Erin field.

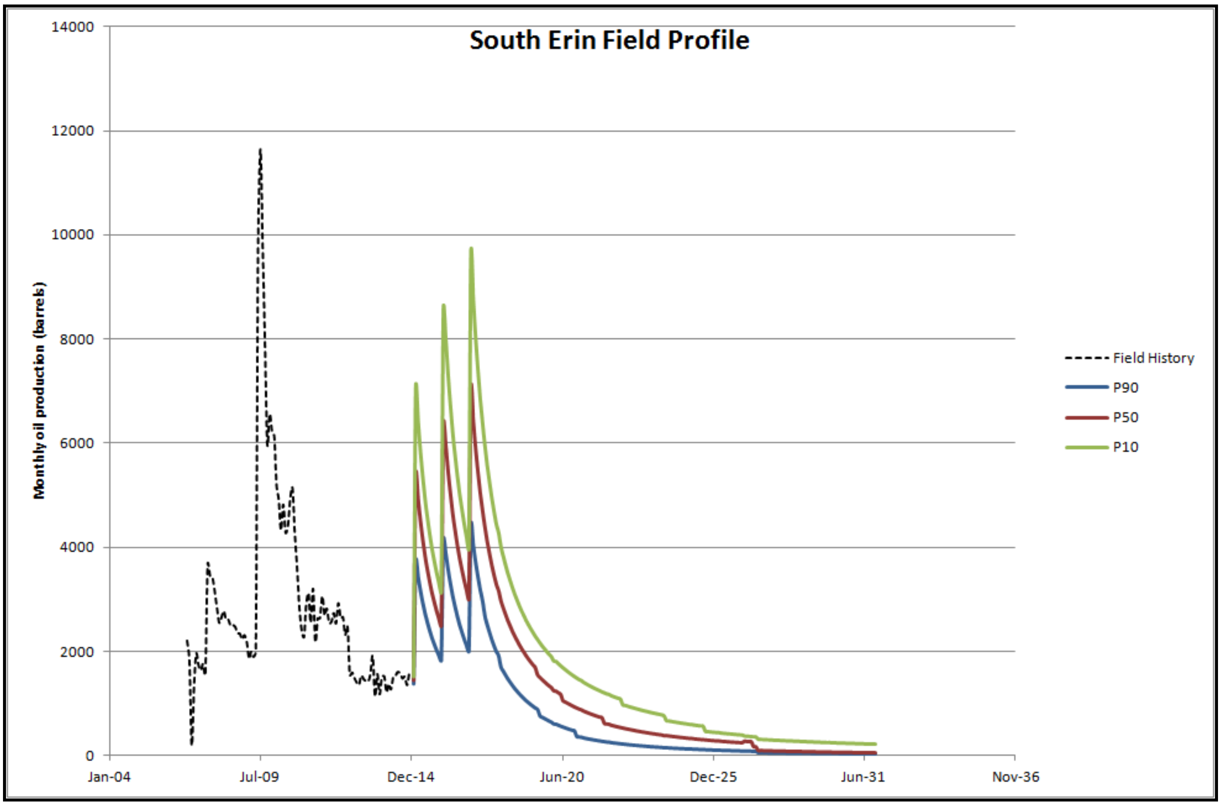

Figure 7.3: Oil Production Forecast for the South Erin Field

8. CAPITAL & OPERATING COSTS

RPS cost profiles were created for the 1P, 2P and 3P Reserves based on data provided by REX and from RPS regional knowledge. Costs described below are in 2015 real terms. We have assumed there are no significant contingencies to the development such as social, environmental, health and safety factors.

The developed scenario contains production from the five existing producing wells with capital investment in 2015: well completion costs of US$2 million occurred in the first quarter of 2015, with additional capital costs of US$800,000 in 2015 for the purchase of transfer unit and recompletion of two wells in the third quarter. No other capital investment for the developed Reserves is envisaged. For 2015 the operating costs and general overhead costs were assumed as US$0.625MM.

The Undeveloped Reserves assume additional drilling of two wells in late 2015 and two wells in late 2016 at a combined cost of US$3.4M. In addition to the operating and general and administrative (G&A) costs for the Developed Reserves, an annual opex of US$50,000 per well was assumed for the Undeveloped Reserves.

In both Developed, and Developed plus Undeveloped cases, operating costs have been reduced over the life of the field to reflect the decline in production.

The terms of the licence require the company to make abandonment provisions of US$0.28/bbl. RPS has assumed a decommissioning cost at the end of field life for Developed and Undeveloped cases of US$1.55MM and US$2.65MM respectively.

9. FINANCIAL ANALYSIS

9.1 Assumptions

9.1.1 General

Post tax cashflows in US Dollars from 1st January 2015 were calculated for South Erin Licence cases using RPS forecasts of costs and prices. An annual inflation rate of 2% was assumed and applied to both costs and revenues. A constant exchange rate of 6.49 Trinidad and Tobago Dollar to 1 US Dollar was assumed.

9.1.2 Oil Prices

The evaluation was based on the RPS long term forecast for West Texas Intermediate (WTI) crude (long term price of US$80/stb in REAL 2015$ from 2020 onwards) as shown in Table 9.1. The observed realised sales prices for South Erin relative to WTI prices during the period January 2014 to December 2014 were used as the basis for South Erin oil price assumptions: a constant -8% was applied to the WTI price as seen in Table 9.1.

	WTI Price Case (US$/stb, MOD)	Base South Erin Price Case (US$/stb, MOD)
2015	64.41	59.26
2016	68.00	62.56
2017	71.50	65.78
2018	75.00	69.00
2019	81.00	74.52
2020	88.33	81.26
2021	90.09	82.89
2022	91.89	84.54
2023	93.73	86.23
2024	95.61	87.96
2025	97.52	89.72
2026 onwards	+ 2% p.a.	+ 2% p.a.

Table 9.1: RPS Forecast Oil Prices

9.2 Methodology

The production potential of the South Erin field was assessed with RPS forecasts of 1P, 2P and 3P Reserves and development project assumptions.

A discounted cashflow model was used for the Reserves cases with RPS forecast of future production, prices and costs. The model honours the applicable licence terms and Government taxes to provide net REX entitlement Reserves and post-tax cashflows net to REX�s share.

9.3 Licence

REX�s entitlement to production from the South Erin Block is laid down in the Farmout Agreement (Sub-Licence) of 2nd October 2013 between Petroleum Company of Trinidad and

Tobago Limited (ñPetrotrinò) and Jasmin Oil and Gas Ltd. A licence extension for 19 years was granted in 2012 and the expiry date is now 2031.

RIH held a 64.17% interest in the Farmout Agreement (sub-licence) through its ownership of REX. Since March 2014 RIH has increased its interest in REX to 98.36%. REX owns 100% of Jasmin Oil and Gas Limited.

9.3.1 Petrotrin Overriding Royalties

An Over Riding Royalty (ORR) on oil production is payable to Petrotrin that varies according to oil price and oil production. For example, within the oil price band of US$90 to US$130 per barrel, the BASE ORR% rate for Base Production is 25% and the Enhanced ORR% for production above Base Production is 16%, where Base Production is defined in the agreement in barrels of oil per month on an annual basis for the duration of the agreement.

9.3.2 Economic Limit

An economic limit has been applied to the RPS production forecasts in accordance with PRMS guidelines: "Economic limit is defined as the production rate beyond which the net operating cash flows (after royalties or share of production owing to others) from a project, which may be an individual well, lease, or entire field, are negative." The economic limit test for each field is therefore based on the operating cashflow calculated as follows:

> Field Revenues less: Government Royalty, Petrotrin Overriding Royalty (ORR), Supplemental Petroleum Tax (SPT) and Operating Costs.

9.4 Fiscal Regime

The applicable fiscal terms exist within a tax and royalty regime. A Government Royalty applies to production and there is a Supplemental Petroleum Tax and a Petroleum Profit Tax, plus further small levies.

9.4.1 Royalty

For the South Erin Farmout Sub-Licence the Royalty rate is 12.5% applicable to oil from the contract area without any deductions.

9.4.2 Supplemental Petroleum Tax

SPT is payable to the Government on revenues after the Government Royalty and the Petrotrin ORR have been deducted, at a rate for onshore licences that varies with oil price as shown in Table 9.2.

Oil Price $/bbl	Onshore SPT Rate
Price Ò$50.00	0%
$50.00 Price Ò$90.00	18%
$90.00 Price Ò$200.00	18% plus 0.2% of (Oil Price less $90.00)
Price >$200.00	40%

Table 9.2: Supplemental Petroleum Tax Rates

An Investment Tax Credit of 20% of capital expenditure (ñCapexò) is allowable against the annual SPT charge, and unused Investment Tax Credits can be carried forward for one year.

9.4.3 Petroleum Production Levy

The Petroleum Production Levy (PPL) is applied at a rate of 4% of all gross oil revenues if company production is in excess of 3,500 barrels of oil per day. RPSÕs forecast of Reserves in REX's wholly-owned subsidiary company Jasmin Oil and Gas Limited does not exceed this limit so no PPL is expected.

9.4.4 Green Fund Levy and Petroleum Impost

The Green Fund Levy (GFL) is calculated as a percentage (currently 0.1%) of total gross revenues, and these payments are not tax deductible. A small Petroleum Impost is also payable.

9.4.5 Petroleum Profits Tax

The Petroleum Profits Tax (PPT) is applicable to all oil and gas producers and is applied to the net profits from Jasmin Oil and Gas Limited's operations at the current applicable tax rate of 50%. The net profit is derived by deducting from the gross income all royalties, taxes and levies with the exception of the GFL. Tax losses can be brought forward indefinitely. Balances at 31 December 2014 provided by REX, have been used in the PPT tax calculations. The capital allowances for PPT are summarised in Table 9.3.

Capex Category	Allowances effective 1 January 2014 (2014 Budget proposals)
Exploration	From 2014 to 2017, 100% of costs to be written off in the year the expenditure is incurred. From 2018, allowances of 50%, 30% and 20% will apply respectively in the first, second and third years of the expenditure.
Tangible and Intangible	Allowances of 50%, 30% and 20% will apply respectively in the first, second and third years of the expenditure.
Workovers and Qualifying Sidetracks	100% of costs to be written off in the year the expenditure is incurred.

Table 9.3: Petroleum Profits Tax Capital Allowances

9.4.6 Unemployment Levy

The applicable rate is 5% of the net taxable income before loss relief.

9.5 Reserves

REX's Reserves in South Erin as of 31st December 2014 are summarised in Table 9.4.

Field	Gross Reserves (Mstb)[1]			RIH Net WI Reserves (Mstb)[1,2]			RIH Net Reserves Entitlement (Mstb)[1,2,3]		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
Developed	48.0	82.4	158.9	47.2	81.0	156.3	31.2	54.2	104.1
Developed plus Undeveloped	172.7	336.1	492.8	169.9	330.6	484.7	116.6	229.0	337.9

1 1P cases have negative Net Present Value at 10% discount rate (NPV10).
2 RIH owns 98.36% of REX which is 100% owner of Jasmin Oil and Gas Limited.
3 RIH Net Reserves Entitlement is RIH's WI share of Reserves after the deduction of Government Royalty and Petrotrin Over-riding Royalty.

Table 9.4: Reserves as of 31 December 2014

The 98.36% WI of field cash-flows associated with the Reserves cases are presented in Appendix 2.

10. INTERPRETATION AND CONCLUSIONS

RPS has estimated Reserves for the developed and planned wells in the South Erin Licence.

For the year-end 2013 report by RPS (issued March 2014) the developed wells were considered representative of the future undrilled wells and (excluding 1ER-102) the average EUR was 82,000 barrels per well. A generalised decline curve was produced to give an EUR of 82,000 barrels with a rate of decline averaging the successful developed wells. Test results from new well ER-105 demonstrate a reduction in production rate of 20% can be expected compared to previous wells and the decline curve and EUR have been revised. Test results for well ER-106 show a significant reduction in expected production.

Reserves are estimated for the following:

- Revised Reserves for the currently producing wells ER-98, ER-99, ER-100 and ER-101. No recompletions of these wells are planned.
- New Reserves for recent developed well ER-105. No Reserves are allocated to ER-106.
- Undeveloped Reserves for four planned wells to be drilled in 2015 or 2016 in the vicinity of ER-105 discovery well and within the field area.

Economics have been determined for the Developed Reserves and the Developed plus Undeveloped Reserves, and allow for Government Royalty, Petrotrin Overriding Royalty (ORR), Supplemental Petroleum Tax (SPT) and Operating Costs.

Reserves in South Erin attributable to RIH's indirectly owned subsidiary Caribbean Rex Ltd ("REX") as of 31st December 2014 are summarised in the following table. RIH has 98.36% ownership of REX.

Category	Gross Attributable to Licence (Mstb)	Net Attributable to RIH[1,2] (Mstb)	Change in Net Attributable from Previous Update	Remarks
Reserves				
	Oil Reserves			
1P	170	117	+2.6%	*1P reserves are uneconomic. Includes Undeveloped Reserves*
2P	331	229	-11.2%	*Includes Undeveloped Reserves*
3P	485	338	-24.6%	*Includes Undeveloped Reserves*

1. *Net Attributable is the net share of Reserves after the deduction of Government Royalty and Petrotrin Over-riding Royalty.*
2. *Rex International Holding Lmited has 98.36% ownership of Caribbean Rex Ltd which has 100% ownership of Jasmin Oil and Gas Limited.*

Table 10.1: Summary of Reserves as at 31st December 2014

11. Recommendations

There are no recommendations following this report.

12. DATE AND SIGNATURE

At the request of Rex International Holding Limited (ñRIHò), RPS Energy Consultants Limited (ñRPSò) has prepared an evaluation of selected oil Reserves and the net present values of those Reserves for South Erin Block, onshore Trinidad (ñSouth Erinò), as of 31st December 2014.

The report was issued on 20th March 2015 and is signed on behalf of RPS Energy Consultants Limited by Gordon R. Taylor.

Gordon Taylor, C.Eng, C.Geol
Director, Head of Subsurface

APPENDIX 1: GLOSSARY OF TERMS AND ABBREVIATIONS

API	American Petroleum Institute
asl	above sea level
B	Billion
bbl(s)	Barrels
bbls/d	barrels per day
Bcm	billion cubic metres
B_g	gas formation volume factor
B_{gi}	gas formation volume factor (initial)
B_o	oil formation volume factor
B_{oi}	oil formation volume factor (initial)
B_w	water volume factor
bopd	barrels of oil per day
BTU	British Thermal Unit
Bscf	billions of standard cubic feet
bwpd	barrels of water per day
CO_2	Carbon dioxide
condensate	liquid hydrocarbons which are sometimes produced with natural gas and liquids derived from natural gas
cP	Centipoise
C_{ROCK}	rock compressibility
C_w	water compressibility
DBA	Decibels
E_a	areal sweep efficiency
EMV	Expected Monetary Value
EPSA	Exploration and Production Sharing Agreement
ESD	emergency shut down
EUR	Expected ultimate recovery
E_{vert}	vertical sweep efficiency
FBHP	flowing bottom hole pressure
FTHP	flowing tubing head pressure
ft	feet
ftSS	depth in feet below sea level
FVF	Formation volume factor
GDT	Gas Down To

GIP	Gas in Place
GIIP	Gas Initially in Place
GOR	gas/oil ratio
GRV	gross rock volume
GWC	gas water contact
H_2S	Hydrogen sulphide
HIC	hydrogen induced cracking
IRR	internal rate of return
KB	Kelly Bushing
k_a	absolute permeability
k_h	horizontal permeability
km	kilometres
km^2	square kilometres
kPa	kilopascals
k_r	relative permeability
k_{rg}	relative permeability of gas
k_{rgcl}	relative permeability of gas @ connate liquid saturation
k_{rog}	relative permeability of oil-gas
k_{roso}	relative permeability at residual oil saturation
k_{roswi}	relative permeability to oil @ connate water saturation
k_v	vertical permeability
LNG	Liquefied Natural Gases
LPG	Liquefied Petroleum Gases
M	thousand
MM	million
M$	thousand US dollars
MM$	million US dollars
MD	measured depth
mD	permeability in millidarcies
m^3	cubic metres
m^3/d	cubic metres per day
MMscf/d	millions of standard cubic feet per day
m/s	metres per second
msec	milliseconds
mV	millivolts
Mt	thousands of tonnes
MMt	millions of tonnes

MPa	mega pascals
NTG	net to gross ratio
NGL	Natural Gas Liquids
NPV	Net Present Value
OWC	oil water contact
P_b	bubble point pressure
P_c	capillary pressure
petroleum	deposits of oil and/or gas
phi	porosity fraction
p_i	initial reservoir pressure
PI	productivity index
ppm	parts per million
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
p_{wf}	flowing bottom hole pressure
PVT	pressure volume temperature
rb	barrel(s) of oil at reservoir conditions
rcf	reservoir cubic feet
RFT	repeat formation tester
RKB	relative to kelly bushing
rm^3	reservoir cubic metres
SCADA	supervisory control and data acquisition
SCAL	Special Core Analysis
scf	standard cubic feet measured at 14.7 pounds per square inch and 60° F
scf/d	standard cubic feet per day
scf/stb	standard cubic feet per stock tank barrel
SGS	Sequential Gaussion Simulation
SIS	Sequential Indicator Simulation
sm^3	standard cubic metres
S_o	oil saturation
S_{or}	residual oil saturation
S_{orw}	residual oil saturation (waterflood)
S_{wc}	connate water saturation
S_{oi}	irreducible oil saturation
SSCC	sulphur stress corrosion cracking
stb	stock tank barrels measured at 14.7 pounds per square inch

	and 60° F
stb/d	stock tank barrels per day
STOIIP	stock tank oil initially in place
S_w	water saturation
$	United States Dollars
t	tonnes
THP	tubing head pressure
Tscf	trillion standard cubic feet
TVDSS	true vertical depth (sub-sea)
TVT	true vertical thickness
TWT	two-way time
US$	United States Dollar
V_{sh}	shale volume
W/m/K	watts/metre/° K
WC	water cut
WUT	Water Up To
ϕ	porosity
□	viscosity
□$_{gb}$	viscosity of gas
□$_{ob}$	viscosity of oil
□$_{w}$	viscosity of water

APPENDIX 2: SOUTH ERIN CASH-FLOWS

These cash flows are presented at 98.36 % WI basis

RPS Energy | CASH FLOW SUMMARY | SOUTH ERIN | 1P DEVELOPED | REX (Jasmin Oil & Gas Ltd) | 98.36%

FUTURE REVENUE, COSTS AND NET CASH FLOW - US$ MILLIONS, MOD

Year		Company Net Production before Royalty & ORR	Company Net Production after Royalty & ORR	Oil Price WTI	Company Field Revenues before Royalty & ORR	Royalty	PETROTRIN ORR	Revenue after Royalties	OPEX & G&A	CAPEX	ABEX	Petroleum Production Levy	SPT	Green Fund Levy	Petroleum Impost	Company's Net Cashflow Before PPT Tax	Petroleum Profits Tax	Unemployment Levy	Company's Net Cashflow After Tax
		stb/d	stb/d	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$
		0.05	0.03	0	2.86	0.36	0.61	1.89	1.19	2.75	1.59	-	-	0.00	0.00	-3.65	-	-	-3.65
1	2015	82	55	64.41	1.78	0.22	0.37	1.19	0.61	2.75	-	-	-	0.00	0.00	-2.18	-	-	-2.18
2	2016	47	30	68.00	1.08	0.13	0.25	0.69	0.58	-	-	-	-	0.00	0.00	0.12	-	-	0.12
3	2017	-	-	71.50	-	-	-	-	-	-	1.59	-	-	-	-	-1.59	-	-	-1.59
4	2018	-	-	75.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	2019	-	-	81.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	2020	-	-	88.33	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	2021	-	-	90.09	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	2022	-	-	91.89	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	2023	-	-	93.73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	2024	-	-	95.61	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	2025	-	-	97.52	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	2026	-	-	99.47	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	2027	-	-	101.46	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	2028	-	-	103.49	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	2029	-	-	105.56	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	2030	-	-	107.67	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	2031	-	-	109.82	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Sub Total	0.047	0.031		2.86	0.36	0.61	1.89	1.19	2.75	1.59	-	-	0.00	0.00	-3.65	-	-	-3.65
	Remaining																		
	Total	0.047	0.031		2.86	0.36	0.61	1.89	1.19	2.75	1.59	-	-	0.00	0.00	-3.65	-	-	-3.65

RPS Energy CASH FLOW SUMMARY SOUTH ERIN 2P DEVELOPED REX (Jasmin Oil & Gas Ltd) 98.36%

FUTURE REVENUE, COSTS AND NET CASH FLOW - US$ MILLIONS, MOD

Year		Company Net Production before Royalty & ORR	Company Net Production after Royalty & ORR	Oil Price WTI	Company Field Revenues before Royalty & ORR	Royalty	PETROTRIN ORR	Revenue after Royalties	OPEX & G&A	CAPEX	ABEX	Petroleum Production Levy	SPT	Green Fund Levy	Petroleum Impost	Company's Net Cashflow Before PPT Tax	Petroleum Profits Tax	Unemployment Levy	Company's Net Cashflow After Tax
		stb/d	stb/d	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$
		0.08	**0.05**	**0**	**4.98**	**0.62**	**1.03**	**3.33**	**1.73**	**2.75**	**1.62**	**-**	**0.12**	**0.00**	**0.00**	**-2.90**	**-**	**-**	**-2.90**
1	2015	114	78	64.41	2.48	0.31	0.47	1.70	0.61	2.75	-	-	-	0.00	0.00	-1.68	-	-	-1.68
2	2016	64	42	68.00	1.47	0.18	0.32	0.96	0.58	-	-	-	-	0.00	0.00	0.38	-	-	0.38
3	2017	43	28	71.50	1.03	0.13	0.24	0.67	0.54	-	-	-	0.12	0.00	0.00	0.01	-	-	0.01
4	2018	-	-	75.00	-	-	-	-	-	-	1.62	-	-	-	-	-1.62	-	-	-1.62
5	2019	-	-	81.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	2020	-	-	88.33	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	2021	-	-	90.09	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	2022	-	-	91.89	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	2023	-	-	93.73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	2024	-	-	95.61	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	2025	-	-	97.52	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	2026	-	-	99.47	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	2027	-	-	101.46	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	2028	-	-	103.49	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	2029	-	-	105.56	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	2030	-	-	107.67	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	2031	-	-	109.82	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Sub Total	0.081	0.054		4.98	0.62	1.03	3.33	1.73	2.75	1.62	-	0.12	0.00	0.00	-2.90	-	-	-2.90
	Remaining																		
	Total	**0.081**	**0.054**		**4.98**	**0.62**	**1.03**	**3.33**	**1.73**	**2.75**	**1.62**	**-**	**0.12**	**0.00**	**0.00**	**-2.90**	**-**	**-**	**-2.90**

RPS Energy CASH FLOW SUMMARY SOUTH ERIN 3P DEVELOPED REX (Jasmin Oil & Gas Ltd) 98.36%

FUTURE REVENUE, COSTS AND NET CASH FLOW - US$ MILLIONS, MOD

Year		Company Net Production before Royalty & ORR	Company Net Production after Royalty & ORR	Oil Price WTI	Company Field Revenues before Royalty & ORR	Royalty	PETROTRIN ORR	Revenue after Royalties	OPEX & G&A	CAPEX	ABEX	Petroleum Production Levy	SPT	Green Fund Levy	Petroleum Impost	Company's Net Cashflow Before PPT Tax	Petroleum Profits Tax	Unemployment Levy	Company's Net Cashflow After Tax
		stb/d	stb/d	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$
		0.16	0.10	0	10.45	1.31	2.21	6.94	3.76	2.75	1.79	-	0.70	0.01	0.01	-2.07	-	0.02	-2.09
1	2015	146	101	64.41	3.16	0.40	0.57	2.19	0.61	2.75	-	-	-	0.00	0.00	-1.18	-	0.01	-1.19
2	2016	80	54	68.00	1.84	0.23	0.38	1.23	0.58	-	-	-	0.06	0.00	0.00	0.58	-	-	0.58
3	2017	54	35	71.50	1.29	0.16	0.30	0.83	0.54	-	-	-	0.15	0.00	0.00	0.14	-	-	0.14
4	2018	41	26	75.00	1.03	0.13	0.24	0.66	0.50	-	-	-	0.12	0.00	0.00	0.05	-	0.00	0.04
5	2019	33	21	81.00	0.91	0.11	0.21	0.58	0.45	-	-	-	0.11	0.00	0.00	0.03	-	0.00	0.02
6	2020	28	18	88.33	0.84	0.11	0.19	0.54	0.41	-	-	-	0.10	0.00	0.00	0.04	-	0.00	0.03
7	2021	25	16	90.09	0.75	0.09	0.17	0.48	0.36	-	-	-	0.09	0.00	0.00	0.03	-	0.00	0.03
8	2022	21	13	91.89	0.64	0.08	0.15	0.41	0.31	-	-	-	0.07	0.00	0.00	0.03	-	0.00	0.03
9	2023	-	-	93.73	-	-	-	-	-	-	1.79	-	-	-	-	-1.79	-	-	-1.79
10	2024	-	-	95.61	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	2025	-	-	97.52	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	2026	-	-	99.47	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	2027	-	-	101.46	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	2028	-	-	103.49	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	2029	-	-	105.56	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	2030	-	-	107.67	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	2031	-	-	109.82	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Sub Total	0.156	0.104		10.45	1.31	2.21	6.94	3.76	2.75	1.79	-	0.70	0.01	0.01	-2.07	-	0.02	-2.09
	Remaining																		
	Total	0.156	0.104		10.45	1.31	2.21	6.94	3.76	2.75	1.79	-	0.70	0.01	0.01	-2.07	-	0.02	-2.09

RPS Energy CASH FLOW SUMMARY SOUTH ERIN 1P DEVELOPED & UNDEVELOPED REX (Jasmin Oil & Gas Ltd) 98.36%

FUTURE REVENUE, COSTS AND NET CASH FLOW - US$ MILLIONS, MOD

Year		Company Net Production before Royalty & ORR	Company Net Production after Royalty & ORR	Oil Price WTI	Company Field Revenues before Royalty & ORR	Royalty	PETROTRIN ORR	Revenue after Royalties	OPEX & G&A	CAPEX	ABEX	Petroleum Production Levy	SPT	Green Fund Levy	Petroleum Impost	Company's Net Cashflow Before PPT Tax	Petroleum Profits Tax	Unemployment Levy	Company's Net Cashflow After Tax
		stb/d	stb/d	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$
		0.17	**0.12**	**0**	**10.90**	**1.36**	**2.05**	**7.48**	**2.74**	**6.13**	**2.82**	**-**	**0.72**	**0.01**	**0.01**	**-4.95**	**-**	**0.01**	**-4.96**
1	2015	82	55	64.41	1.78	0.22	0.37	1.19	0.61	4.43	-	-	-	0.00	0.00	-3.85	-	-	-3.85
2	2016	143	99	68.00	3.28	0.41	0.60	2.28	0.68	1.71	-	-	-	0.00	0.00	-0.11	-	-	-0.11
3	2017	164	114	71.50	3.94	0.49	0.70	2.75	0.74	-	-	-	0.49	0.00	0.00	1.51	-	0.01	1.50
4	2018	75	50	75.00	1.90	0.24	0.39	1.27	0.70	-	-	-	0.23	0.00	0.00	0.33	-	-	0.33
5	2019	-	-	81.00	-	-	-	-	-	-	2.82	-	-	-	-	-2.82	-	-	-2.82
6	2020	-	-	88.33	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	2021	-	-	90.09	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	2022	-	-	91.89	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	2023	-	-	93.73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	2024	-	-	95.61	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	2025	-	-	97.52	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	2026	-	-	99.47	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	2027	-	-	101.46	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	2028	-	-	103.49	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	2029	-	-	105.56	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	2030	-	-	107.67	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	2031	-	-	109.82	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Sub Total	0.170	0.117		10.90	1.36	2.05	7.48	2.74	6.13	2.82	-	0.72	0.01	0.01	-4.95	-	0.01	-4.96
	Remaining																		
	Total	**0.170**	**0.117**		**10.90**	**1.36**	**2.05**	**7.48**	**2.74**	**6.13**	**2.82**	**-**	**0.72**	**0.01**	**0.01**	**-4.95**	**-**	**0.01**	**-4.96**

RPS Energy CASH FLOW SUMMARY SOUTH ERIN 2P DEVELOPED & UNDEVELOPED REX (Jasmin Oil & Gas Ltd) 98.36%

FUTURE REVENUE, COSTS AND NET CASH FLOW - US$ MILLIONS, MOD

Year		Company Net Production before Royalty & ORR	Company Net Production after Royalty & ORR	Oil Price WTI	Company Field Revenues before Royalty & ORR	Royalty	PETROTRIN ORR	Revenue after Royalties	OPEX & G&A	CAPEX	ABEX	Petroleum Production Levy	SPT	Green Fund Levy	Petroleum Impost	Company's Net Cashflow Before PPT Tax	Petroleum Profits Tax	Unemployment Levy	Company's Net Cashflow After Tax
		stb/d	stb/d	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$
		0.33	0.23	0	22.15	2.77	4.07	15.31	4.61	6.13	2.99	-	1.80	0.02	0.02	-0.26	-	0.19	-0.46
1	2015	114	78	64.41	2.48	0.31	0.47	1.70	0.61	4.43	-	-	-	0.00	0.00	-3.35	-	-	-3.35
2	2016	225	158	68.00	5.15	0.64	0.88	3.63	0.68	1.71	-	-	-	0.01	0.00	1.24	-	0.04	1.20
3	2017	267	189	71.50	6.42	0.80	1.07	4.55	0.74	-	-	-	0.82	0.01	0.00	2.98	-	0.08	2.90
4	2018	129	89	75.00	3.26	0.41	0.60	2.25	0.70	-	-	-	0.41	0.00	0.00	1.14	-	0.04	1.10
5	2019	79	53	81.00	2.15	0.27	0.44	1.45	0.67	-	-	-	0.26	0.00	0.00	0.52	-	0.03	0.49
6	2020	52	34	88.33	1.55	0.19	0.36	1.00	0.62	-	-	-	0.18	0.00	0.00	0.20	-	0.01	0.19
7	2021	38	24	90.09	1.14	0.14	0.26	0.74	0.58	-	-	-	0.13	0.00	0.00	0.02	-	0.00	0.02
8	2022	-	-	91.89	-	-	-	-	-	-	2.99	-	-	-	-	-2.99	-	-	-2.99
9	2023	-	-	93.73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	2024	-	-	95.61	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	2025	-	-	97.52	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	2026	-	-	99.47	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	2027	-	-	101.46	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	2028	-	-	103.49	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	2029	-	-	105.56	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	2030	-	-	107.67	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	2031	-	-	109.82	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Sub Total	0.331	0.229		22.15	2.77	4.07	15.31	4.61	6.13	2.99	-	1.80	0.02	0.02	-0.26	-	0.19	-0.46
	Remaining																		
	Total	0.331	0.229		22.15	2.77	4.07	15.31	4.61	6.13	2.99	-	1.80	0.02	0.02	-0.26	-	0.19	-0.46

RPS Energy

CASH FLOW SUMMARY **SOUTH ERIN** **3P DEVELOPED & UNDEVELOPED** **REX (Jasmin Oil & Gas Ltd)** **98.36%**

FUTURE REVENUE, COSTS AND NET CASH FLOW - US$ MILLIONS, MOD

Year		Company Net Production before Royalty & ORR	Company Net Production after Royalty & ORR	Oil Price WTI	Company Field Revenues before Royalty & ORR	Royalty	PETROTRIN ORR	Revenue after Royalties	OPEX & G&A	CAPEX	ABEX	Petroleum Production Levy	SPT	Green Fund Levy	Petroleum Impost	Company's Net Cashflow Before PPT Tax	Petroleum Profits Tax	Unemployment Levy	Company's Net Cashflow After Tax
		stb/d	stb/d	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$
		0.48	**0.34**	**0**	**33.15**	**4.14**	**5.96**	**23.05**	**5.67**	**6.13**	**3.12**	**-**	**2.92**	**0.03**	**0.02**	**5.15**	**2.06**	**0.45**	**2.65**
1	2015	146	101	64.41	3.16	0.40	0.57	2.19	0.61	4.43	-	-	-	0.00	0.00	-2.85	-	-	-2.85
2	2016	305	217	68.00	6.98	0.87	1.15	4.96	0.68	1.71	-	-	0.06	0.01	0.01	2.50	-	0.10	2.40
3	2017	368	262	71.50	8.83	1.10	1.43	6.29	0.74	-	-	-	1.13	0.01	0.01	4.40	0.11	0.15	4.14
4	2018	177	124	75.00	4.46	0.56	0.78	3.12	0.70	-	-	-	0.56	0.00	0.00	1.85	0.76	0.08	1.02
5	2019	110	76	81.00	3.00	0.38	0.57	2.06	0.67	-	-	-	0.37	0.00	0.00	1.02	0.51	0.05	0.46
6	2020	78	52	88.33	2.32	0.29	0.47	1.56	0.62	-	-	-	0.28	0.00	0.00	0.65	0.33	0.03	0.29
7	2021	60	39	90.09	1.80	0.23	0.39	1.18	0.58	-	-	-	0.21	0.00	0.00	0.39	0.19	0.02	0.17
8	2022	47	30	91.89	1.44	0.18	0.33	0.93	0.54	-	-	-	0.17	0.00	0.00	0.22	0.11	0.01	0.10
9	2023	37	24	93.73	1.16	0.15	0.27	0.75	0.52	-	-	-	0.14	0.00	0.00	0.09	0.05	0.00	0.04
10	2024	-	-	95.61	-	-	-	-	-	-	3.12	-	-	-	-	-3.12	-	-	-3.12
11	2025	-	-	97.52	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	2026	-	-	99.47	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	2027	-	-	101.46	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	2028	-	-	103.49	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	2029	-	-	105.56	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	2030	-	-	107.67	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	2031	-	-	109.82	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Sub Total	0.485	0.338		33.15	4.14	5.96	23.05	5.67	6.13	3.12	-	2.92	0.03	0.02	5.15	2.06	0.45	2.65
	Remaining																		
	Total	**0.485**	**0.338**		**33.15**	**4.14**	**5.96**	**23.05**	**5.67**	**6.13**	**3.12**	**-**	**2.92**	**0.03**	**0.02**	**5.15**	**2.06**	**0.45**	**2.65**