Independent Geologist's Report on the

Exploration and Production Assets of

Triangle Energy Limited

Roger Whyte
22nd September, 2009

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1 Summary and Conclusions

The author was engaged by BDO Kendalls on 7th September, 2009 to prepare an Independent Geologist's Report on the valuation of the exploration and production assets of Triangle Energy Limited. These assets consist of 100% ownership of Triangle Pase Inc., a company domiciled in Cayman Islands. Triangle Pase Inc. (TPI), formerly Mobil Pase Inc.(MPI), owns and operates a 100% working interest in the Pase Production Sharing Contract. Triangle Energy Limited purchased all the shares in MPI. effective 1st June, 2009.

The Pase PSC covers an area of 920 sq km in north Sumatra, Indonesia, adjacent to ExxonMobil's B Block in which the giant Arun gas field and associated LNG export infrastructure are located. The PSC includes the Pase gas field, discovered in 1983 and developed in 1998. Cumulative production from the field is approximately 184 bcf of gas.

The PSC is due to expire on 11th February, 2011. A key consideration in valuing TPI is an assessment of the likelihood that the Government of Indonesia will renew the PSC. The PSC *per se* does not address the question of renewal but Article 28 of GOI Regulation No. 35/2004 provides that the PSC can be extended, providing it is profitable for the State and is appropriate in terms of potential reserves, market needs and technical/economic feasibility. In recent times, however, this relatively simple process has been complicated by the introduction of oil and gas revenue sharing and *'shared control'* with the provincial governments. Legislation to give effect to *'shared control'* is before the Indonesian parliament but not yet ratified. It is uncertain how the provincial government of Aceh province will exercise such new powers.

The Author has concluded that that there is a small but significant risk that the PSC will not be renewed or not renewable on terms that are sufficiently attractive to TPI to justify the commitment. Given this uncertainty, it is inappropriate to formally attribute value to TPI for any production or other potential that would fall beyond the PSC expiry date. Consequently, this report limits the valuation of TPI to the value of gas production and revenue that might reasonably be expected from Pase field up to February 11th, 2011. It should be noted, however, that if TPI is successful in renewing the PSC on reasonable terms then considerable additional value will be created.

TPI is currently producing approximately 1.8 mmscfd of gas from one well in the Pase gas field and has firm plans to bring a second well back on line after resolution of mechanical issues. This should allow production to increase to over 3.6 mmscfd. Taking this and other technical matters into account the author has conservatively assessed that the field can be expected to produce at least 1.802 bcf of gas prior to PSC expiry.

It is understood that TPI are also investigating the feasibility of bringing two additional field wells A-1 and A-8 back online. If this is achievable in good time then the potential exists for additional production and revenue over and above the current assessment.

Notwithstanding the foregoing statements regarding PSC renewal, it is the author's considered opinion that the Pase area also possesses attractive exploration potential for both gas and oil. If TPI is successful in renewing the PSC then it is likely that additional value could be created over time through production, infill drilling and further exploration, albeit at a moderate risk/reward level.

Valuation of the expected gas production has taken into account the production sharing arrangements of the PSC, the amount of unrecovered sunk cost and the expected gas price. Final net present value of the TPI asset, post Indonesian tax,and at an annual discount rate of 10%, is determined to be **Australian Dollars 8,800,000.00.** This valuation is at the market rates applicable at the date of this Report; 22nd September, 2009.

2 Schedule of Interests

This report covers the valuation of Triangle Energy's interest in the Pase PSC, covering the Pase Block in North Sumatra, Indonesia. The interest is held by Triangle Energy Ltd through it's wholly owned subsidiary Triangle Pase Inc (TPI). TPI owns a 100% of the working interest in the PSC and is the designated operator.

3 Glossary of Terms

MPI	Mobil Pase Inc.
EOM	ExxonMobil Corporation. Created from the merger of Exxon and Mobil in 1999
TPI	Triangle Pase Inc.
MSCF	Thousand standard cubic feet
MMSCF	Million standard cubic feet (of gas)
MMSCFD	Million standard cubic feet per day
MMBTU	Million British thermal units
BCF	Billion cubic feet (of gas)
BBL	Barrel (of oil or condensate)
BOPD	Barrels of oil per day
PSI	Pounds per square inch pressure
BOPD	Barrels of oil per day
DMO	Domestic market obligation. An obligation to supply oil to the domestic market
FTP	First tranche petroleum.
GOI	Government of Indonesia
PSC	Production sharing contract
PPG	Pounds per gallon (drilling mud)
TVDSS	true vertical depth sub sea level

4 Sources of Information

MPI reports and basic data

Rights to reports and data produced by MPI passed to Triangle Energy Limited when they purchased MPI. TPI have granted permission to the author to use, refer to and reproduce any of these reports and data in this report. TPI material used includes:

- MPI quarterly financial reports
- Seismic and well basic data, both hardcopy and in electronic form
- MPI maps
- Original signed Pase Production Sharing Contract
- MPI production reports
- MPI report 'Pase Area – Geoscience Model 2003'
- MPI report R70 "Review of Old Pase Field"
- MPI sponsored field trip to Pase A location, Pase B location and SLS. 16-17 July, 2008

Information owned by GOI

All seismic and well data are owned by the GOI and are considered to be confidential to parties other than TPI. Selections of these data were used in the preparation of this report but TPI and the author are not at liberty to publish or otherwise publicly disclose any such data.

Information supplied directly by TPI

- TPI production reports
- EOM - TPI continuation agreement
- EOM-TPI S&P Agreement
- MPI - PT Arun supply agreement

Information in the Public Domain

- Petroleum Geology of Indonesian Basins. Vol 1 - North Sumatra Basin. Originated and edited by Pertamina – BPPKA.
- Digital Elevation Model (DEM) Available free from United States Geological Survey at ***https://lpdaac.usgs.gov***
- USGS ASPAC map. Open file report 97-470F. Published on the world wide web at ***http://pubs.usgs.gov***
- BPMIGAS "LNG in INDONESIA" available for free download at ***http://www.bpmigas.com/english/act-LNG.asp***
- News items regarding security situation in Aceh. Various articles in the Jakarta Post. Available at ***http://www.thejakartapost.com***

5 Technical and Commercial Evaluation

5.1 Historical background

Hydrocarbon exploration in the North Sumatran Basin began before the turn of the 20th century during the Dutch colonial days. The early phase was originally undertaken by Bataafsche Petroleum Maatschappij (BPM), a subsidiary of the Shell Company, and was mainly based on surface geological mapping. Numerous shallow wells were drilled on surface anticlines and adjacent to surface oil seeps. BPM discovered several oil fields to the southeast of the area now covered by Pase PSC, notably Telaga Said (1885), Perlak (1910) and Rantau (1929). BPM also discovered a small, shallow oilfield just to the north of the current Pase PSC, referred to by EOM as the 'Old Pase' field,. The field was shut-in at the time of Japanese occupation and never returned to production. Little is known about the history of exploration or production records from this field.

After WW II the new Indonesian Government moved to revive oil exploration and production by establishing Pertamina, the National Oil Company. Pertamina was granted rights to all exploration and production in Indonesia. Field rehabilitation contracts in North Sumatra were issued to NOSODECO in 1960 and Asamera in 1961.

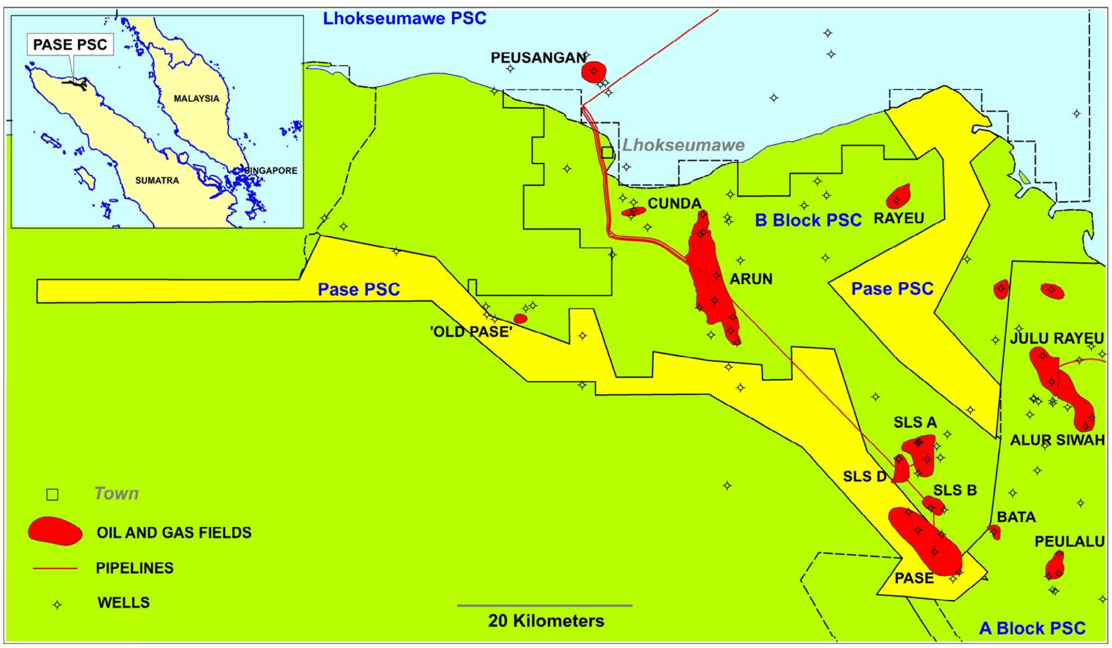

Figure 1 Pase location map

Mobil Corporation acquired the B Block PSC in 1968 and went on to discover the giant Arun gas field in 1971. A recoverable reserve of approximately 20 trillion cubic feet of condensate-rich gas was found in lower to middle Miocene reef and associated carbonate facies that in places exceed 300 m in thickness.

Subsurface studies and drilling results indicate the Arun field size is more than 8,560 Ha. The structure is approximately 18.5 km long and 5.0 km wide. The gas accumulation is characterized by abnormally high initial reservoir pressure of 7,100 psi and temperature of 178 deg.C at 3048 m subsea. Well productivities are high because of the good permeability of the limestone. Maximum recorded flow rate from a single well at Arun was approximately 300 mmscfd.

Following success at Arun, Mobil was awarded the Pase PSC on 12th February, 1981. The PSC had a 30 year life. The Pase Block adjoins the B Block to the south and lies in the foothills between the coastal plains of the B Block and the Barisan Mountains (Figure 2).

The Pase PSC was a natural extension of Mobil's efforts to find additional gas reserves to further the life of the Arun LNG project. The PSC award cleared the way for the first phase of modern, seismic-based exploration in the area. In that context it is worth noting that exploration carried out by Mobil (later EOM) in the Pase PSC has concentrated solely on finding LNG scale gas reserves in the deepest part of the geological section. The shallower section which may contain small to medium sized exploration targets (i.e. less than 200 bcf gas) remains relatively unexplored.

The Mobil exploration programme in Pase PSC resulted in the discovery of the Pase gas field in 1983. This field was ultimately developed in two parts. Pase A in 1998 and Pase B in 2002. The field produces from similar aged section to Arun but, unlike Arun, the reservoir consists of fractured limestone, thin, low-porosity, fractured sandstones and fractured basement. Cumulative production of approximately 181 bcf of gas and 735,000 bbls condensate has been achieved. The field suddenly began producing large quantities of water in September 2004 with a consequent rapid decline in gas production rate. The field has produced gas at only a low, intermittent rate since 2005. Clearly, the onset of water caused EOM to cease active exploration and development in the Pase Block.

Triangle is in the process of rehabilitating the Pase field and has established production of around 1.8 mmscf per day since the beginning of August 2009.

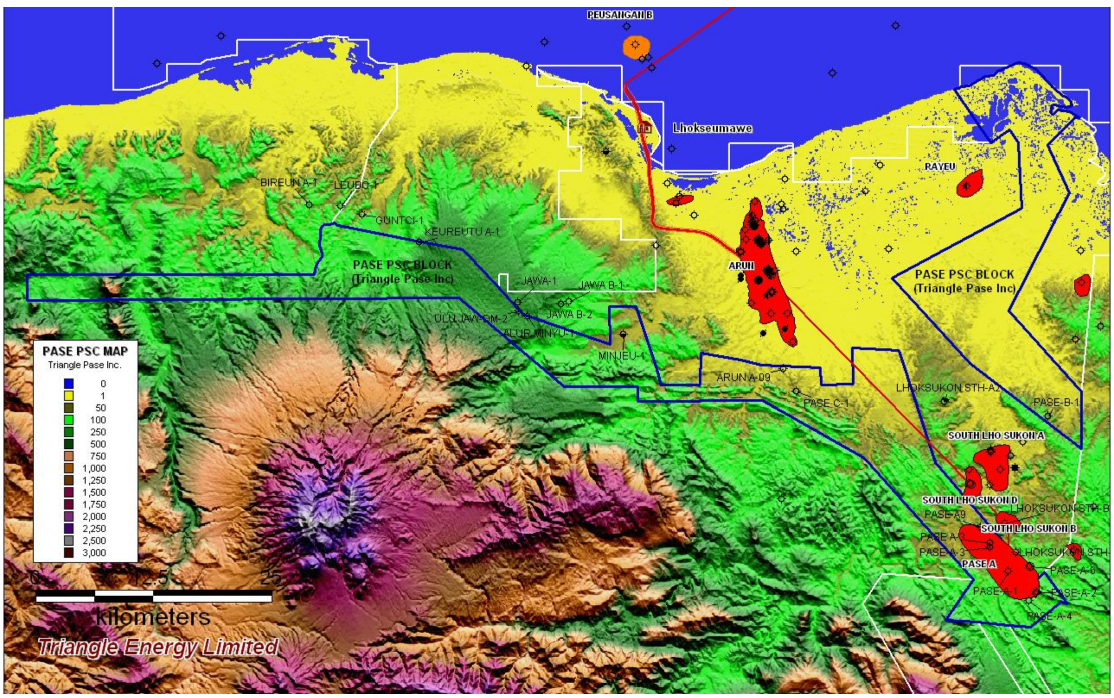

Figure 2 Digital elevation model

Mobil drilled two other exploration wells in the PSC. Pase B-1 was drilled in 1987 to a total depth of 3525 metres. Pase C-1 was drilled in 1988 to a total depth of 3760 metres (Figure 15). Both wells targeted large prospects that were thought to have reefal development similar to Arun. While both failed to find the anticipated reef facies they did encounter indications of gas which provide encouragement for future exploration.

Aceh province experienced civil unrest between 1999 and 2002. Much of this was directed towards EOM who were seen as the principal perpetrators of the export of wealth from the region. The unrest took the form of sabotage of field plant and equipment and, in a few cases, Mobil personnel were fired upon by small arms. As a precaution the Pase field was shut in from September 2001 until April 2002 for security reasons. The problems have now subsided following implementation of the post-Suharto government policy to remit a proportion of oil and gas revenue back to the provinces. There have been no serious incidences of civil unrest since 2002. The field is guarded by a detachment of about 40 Indonesian soldiers.

A process for the divestment of Pase PSC was initiated by EOM in early 2008 through IndigoPool. Several companies were interested in acquiring the asset but the sale process was interrupted by the Global Financial Crisis. Triangle Energy Limited was introduced to the opportunity by one of the parties that had participated in the IndigoPool sale process, subsequently acquiring 100% of the shares in Mobil Pase Inc. (MPI) with effect from 1st June 2009. The MPI name was subsequently changed to Triangle Pase Inc. (TPI).

By purchasing MPI, Triangle Energy Limited have acquired the following rights:

- To rehabilitate and enhance production from the Pase gas field until the PSC expires on February 11th, 2009.
- To supply gas through the EOM infrastructure to the Arun LNG project at the prevailing netback price less reasonable EOM on-costs

TPI have the right to explore for additional reserves, subject to GOI budgetary approval, however this is not practical given the remaining time to PSC expiry. The PSC does not confer on TPI the right to renew the PSC, although it is customary for the GOI to hold renewal discussions with the current PSC holder before the area is offered to the broader market.

5.2 Infrastructure

The Pase Block is approximately 200 km northwest of Medan, the nearest large city. Important means of access to Pase Block are by air, with EOM-operated aircraft maintaining a regular service between Arun Point A, a central control and power site in Arun field, and Medan's Polonia Airport. A road runs from Point A to the Pase A gas processing plant.

Figure 3 Arun LNG plant

Discovery of the Arun gas field led to the development of the Arun LNG scheme. This began operating in 1978, supplying 6.5 million tones annually to Korea and Japan. Arun field is now in decline. The Arun LNG scheme continues to export LNG to Japan and Korea to this day. Arun field itself, however, is close to depletion. Most of the current 700 mmcfd gas supply to the LNG plant now comes from EOM's offshore NSO gas fields with some additional contribution from South Lhok Sukon (SLS) in the 'B' Block adjacent to Pase PSC.

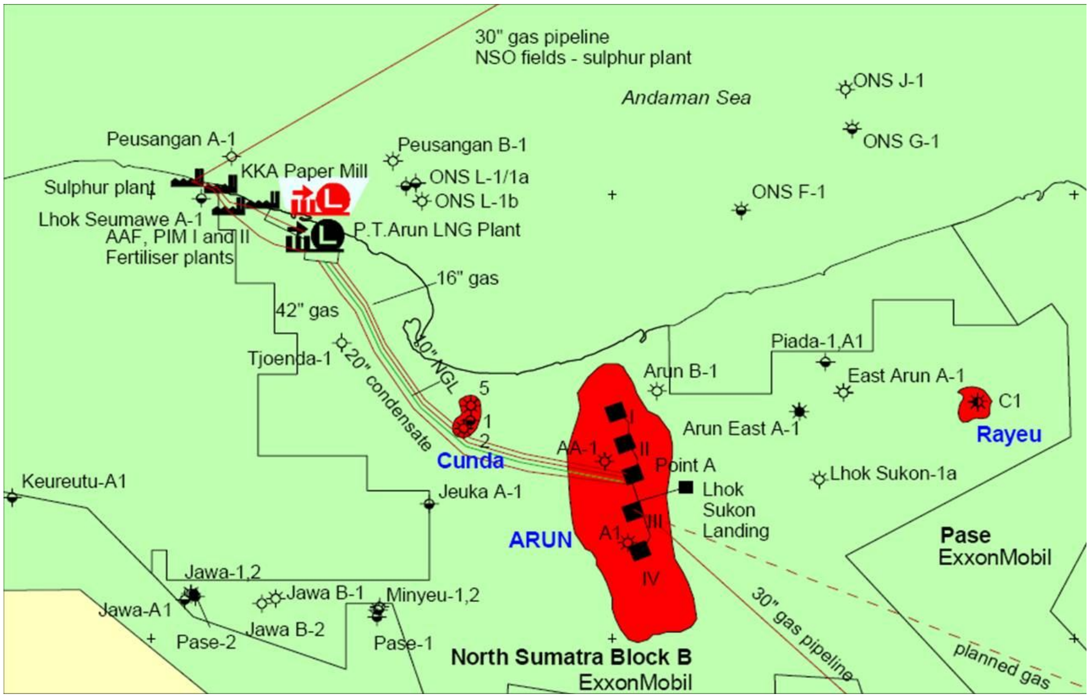

Figure 4 Arun LNG infrastructure

Since commencement of production in 1998, gas from the Pase field has been supplied to the Arun LNG scheme. The Pase field has a dedicated gas processing plant at the Pase A cluster, located adjacent to the A-5 and A-6 wellheads. The Pase processing train consists of air cooling, conventional separation and TEG dehydration. The author visited the site on 17th July, 2008. At that time all plant appeared to be in fundamentally good condition. The plant was manned by EOM personnel during the day only, with automated control at other times. It is understood that Triangle Pase Inc. have now employed dedicated production management personnel for Pase field.

Dehydrated Pase gas/condensate is sent to SLS via a 12" pipeline where it is mingled with SLS gas and sent by 30" pipeline to the Arun processing facility for stripping of condensate, CO2 and Nitrogen. Gas is exported from the Pase plant at a manifold pressure considerably higher than at SLS. This ensures ongoing access to the pipeline without the need for costly compression.

5.3 Due Diligence

5.3.1 PSC Terms

The author has sighted and reviewed the original Production Sharing Contract in detail and is able to confirm the key terms as summarized below. The Pase PSC produces gas and minor condensate from Pase field. It should be noted that, for the purposes of the PSC contract, condensate is considered to be oil.

Date	12th February, 1981
Signatories	Mobil Pase Inc. and Pertamina
Bonuses	Signature Bonus US$5.25mm Production Bonus US$3.0mm when production exceeds 50,000bopd Production Bonus US$6.0mm when production exceeds 100,000 bopd Note: these bonuses apply for oil only.
Term	30 years. Expiry date 11th February, 2011

Commitment	Year 1 US$2.0mm (completed) Year 2 US$11.2mm (completed)
FTP	First Tranche Petroleum. Not included in the original PSC but the correspondence file inherited by Triangle Pase Inc. includes reference to the retrospective imposition of FTP as a condition of approval of the Pase Plan of Development. This is confirmed by the ExxonMobil quarterly reports up to Q1, 2009. According to the quarterly reports the FTP rate is 20%, splittable between GOI and Contractor.
DMO	An obligation for the Contractor to supply oil to the domestic market. Applies to condensate but not (effectively) to gas. Amount to be supplied = 0.340909 x (TP/TI) x (TP – FTP). TP = Total production from Contract Area TI = Total Indonesian oil production The price for DMO oil is set an $0.20 per barrel. The DMO requirement is not imposed for the first 5 years of field life and is not imposed in the event that the recoverable cost pool exceeds gross revenue after FTP for any given year
Taxes	Contractor to be responsible for Corporate tax and personnel income tax. GOI responsible for transfer and sales tax and import/export duties on material, equipment and supplies. GOI tax liability to be paid by Contractor and refunded out of production revenue. Corporate income tax is deducted directly from revenue.
Tax Rates	At the time of signing the PSC the tax rate for PSC Contractors consisted of corporate tax at 45% and dividend tax = (1-corporate tax) x 0.2, i.e. 11%. Total tax rate for PSC Contractors was then 56%. Under the GOI tax regulations these tax rates stay in place for the life of the PSC.
Cost Recovery	Sunk costs can be recovered out of production revenue after FTP and after any investment credit. Unrecovered investment credits and cost pool can be carried forward.
Production share	Contractor Oil: 34.0909% Gas: 68.1818% GOI Oil: 65.9091% Gas: 31.8182% After Corporate tax the Contractor's share becomes: Oil: 15% Gas: 30%
Investment Credit	Contractor may recover an investment credit of 20% of the Capex required for developing production facilities. Investment credit recovery is before cost recovery and only applies provided that, for the project concerned, the GOI share oil entitlement plus 56% of the Contractor share oil entitlement comes to not less than 49% of estimated cumulative production over project life.
Equipment	All plant and equipment purchased pursuant to the PSC becomes GOI property.
Abandonment	The PSC does not impose on the Contractor any obligation to abandon production wells at the end of the PSC life.
Relinquishment	The PSC contract stipulates the following mandatory relinquishments: After 3 years – 25% of original area; After 5 years – additional 20% of original area; After 6 years – further relinquishment such that remaining area is not in excess of the lesser of 40% of the original area or 942 sq km.

5.3.2 PSC Revenue Sharing

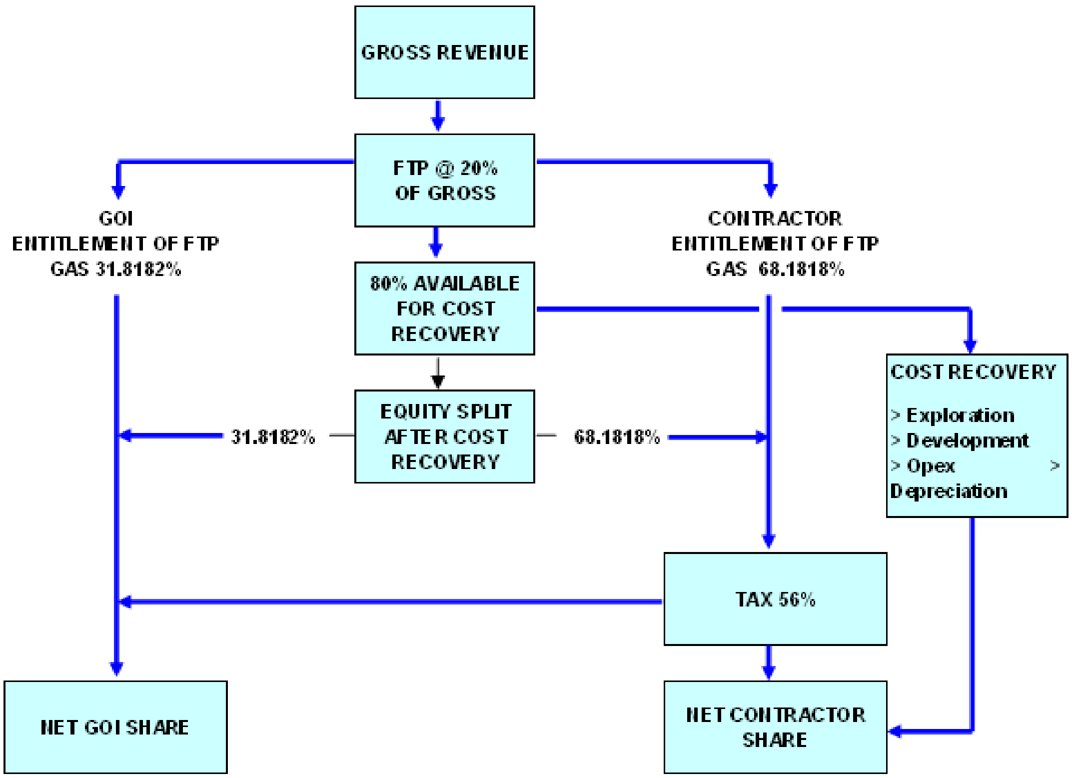

Figure 5. PSC revenue sharing (gas case)

5.3.3 Other Due Diligence

By letter dated 23 March 1987 (original sighted), Pertamina confirmed that the three relinquishments had taken place and the residual area was 920.02 sq km.

All available documentation suggests that the PSC is in good standing. All commitments have been met and all relinquishments made. At the time of the Triangle acquisition, MPI had no employees and therefore no employee liability.

A brief review of the financial status of the PSC was undertaken to assess the quantity, if any, of tax liability, unrecovered sunk costs and future depreciation. The MPI quarterly reports up to Q1 2009 indicate that the situation regarding unrecovered costs is as shown in Table 1.

The unrecovered cost pool remains subject to GOI audit, but there is no reason to suppose it will not be accepted. The unrecovered cost pool going forward to the end of the PSC life in February 2011 will be subject to reductions due to recovery out of post-FTP revenue and additions due to future depreciation and operating costs. The depreciation schedule contained in the Quarterly report for Q1 2009 indicates a balance yet to be depreciated of $20,315,000, so quarterly depreciation expenses will continue until the end of the PSC life. The quarterly rate of depreciation has yet to be determined.

Description	2008	2009	
		Q1	Q2
Balance		5,891	6,972
Addition (from depreciation)		1,101	752
Recovered		17	34
Balance at end of period	5.891	6,975	7,693

Table 1 Unrecovered costs

The unrecovered cost pool was US$7,693,000 at end of Q2 2009. This amount, together with future depreciation and operating costs, will enable TPI to theoretically recover at least US$10,000,000 from post FTP revenue, before production sharing is invoked.

Further conditions of the Share Sales Agreement between EOM and Triangle were:

- EOM to assume all liability for taxes incurred by MPI. prior to June 1st, 2009.
- TPI to pay a royalty of 2% to EOM on gross production revenue.

5.3.4 Gas Price

Under the various agreements between TPI, MPI and PT Arun, TPI has the right to continue the supply of gas from Pase Field to PT Arun LNG until expiry of the current Pase PSC. The gas will be processed by EOM and then liquefied and exported by PT Arun. LNG is sold to Korea under the KOREA II LNG sales agreement. The Author has sighted this agreement. It is commercially sensitive and cannot be reproduced in this report.

In order to arrive at the net price received by TPI for dry gas metered at the Pase plant gate, the following adjustments must be made:

1. The export price is in US$ per MMBTU, a measure of heating value. Pase gas is metered in MSCF. Based on the most recent MPI gas analysis (MPI internal reports); one MSCF of Pase gas is equivalent to 0.923 MMBTU. The gas production must therefore be reduced by this factor to arrive at production in MMBTU.

2. Deduction for PT Arun processing cost.

TPI has been producing gas from Pase field since 1st August, 2009, but has not yet received a statement or payment from PT Arun. Consequently there is uncertainty over the actual net price to be received.

In the absence of any additional information it has been decided that, for the purposes of valuation, a relatively conservative price strip of **US$8.00 flat per MMBTU netback to Pase PSC** will be used up to February 2011. The Author considers this to be reasonable in the light of his reading of the KOREA II LNG sales contract.

5.3.5 Operating Costs

Pase gas is piped to the main Arun processing facility for removal of condensate, CO2 and inert gases. Water produced at Pase is piped to EOM's SLS A facility and reinjected into a water injection well. Costs for these services and the shared pipeline are charged to TPI on a proportional allocated services basis. The proportion attributable to TPI is Pase production versus the total throughput of the facilities. Other operating costs are incurred by TPI directly. TPI has yet to receive an invoice from EOM for allocated expenses. In the absence of such direct information, TPI has estimated a quarterly operating cost of US$400,000. The Author considers this to be reasonable.

5.4 Renewal of PSC

The Pase PSC expires on February 11th, 2011. The PSC Contract itself does not address the question of renewal so there is no guaranteed right per se. GOI regulations allow for negotiations with the PSC holder before expiry of the PSC to establish whether common ground exists that might allow a renewal to proceed.

Article 28 of Regulation No. 35/2004 provides for the following:

- PSC can be extended for a maximum of 20 years for each extension
- The extension must allow for profitability for the State
- Extension to be submitted to the Minister for Energy and Mineral Resources through BPMIGAS no later than 2 years before the termination of the PSC (i.e. February, 2009)
- Minister to take into account potential reserves, potential markets/needs and technical/economic feasibility

TPI was not involved in the PSC and therefore did not apply for an extension by February, 2009. In the author's opinion this may not be a problem, provided other requirements are met, however it gives the GOI a reason to refuse the application if they so desire.

Unfortunately the current political relationship between the Provincial Government of Aceh and the central GOI has created added complexity and uncertainty to the process.

The unrest and separatist sentiment in Aceh following the Asian currency crisis and the resignation of Suharto was centered around dissatisfaction in Aceh over the failure of the Indonesia central Government in Jakarta to remit a proportion of oil and gas revenue from Aceh back to the provincial and district governments. With implementation of a new fiscal decentralization law in January 2001, revenue-sharing formulas came into effect that directed 15 percent of the Indonesian Government's net oil revenues and 30 percent of its net natural gas revenues to provincial and district governments. The Indonesian Government has also agreed to a level of shared control. Recent events illustrate that 'shared control' is interpreted to include the right of the Aceh Provincial Government to have a say in the award and renewal of PSC contracts.

Legislation giving effect to the 'shared control' concept is currently before the Indonesian parliament, but it is uncertain when it will be enacted and what form it will take. Consequently, negotiations for the renewal of other PSCs in Aceh are stalled. The author understands that this includes the A Block PSC operated by Medco.

If TPI is successful in renewing the PSC then it will be on terms equivalent to modern PSCs and will involve a signature bonus and commitment to a firm, three year exploration programme. The signature bonus is likely to be at least US$1.0 million and the commitment programme in the order of two wells and 300 km of 2D seismic. Modern PSCs generally require the Contractor to assume liability for abandonment and to post a bond to guarantee completion of any commitment seismic programme. It is also anticipated that a renewed PSC would involve a commitment to supply gas from future discoveries to the domestic market.

For the above reasons it is the Author's considered opinion that there is a **small but significant risk** that the PSC will not be renewed, or not renewable on terms that are sufficiently attractive to TPI to justify the commitment.

5.5 Geology and Petroleum Systems

5.5.1 Geological Setting

The Pase Block is situated on the southwestern margin of the North Sumatra Basin (NSB). The NSB is a back-arc basin of Tertiary age bounded to the east by onlap onto the Malacca Platform and to the southwest by the Barisan Mountains uplift. It continues for a considerable distance offshore to the north. The oldest NSB sediments encountered are rift stage deposits of Eocene-early Oligocene age. This is broadly similar to other Sumatran Tertiary basins.

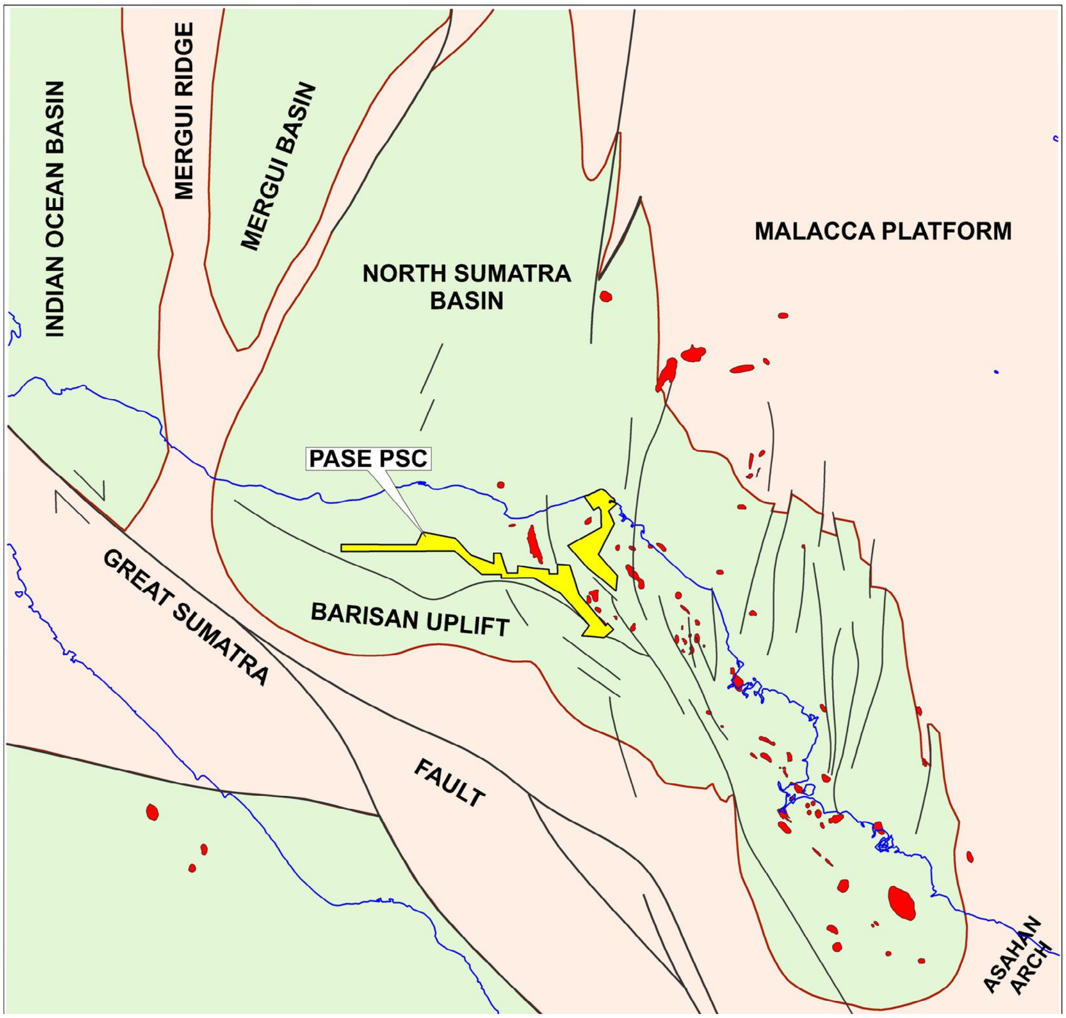

Figure 6 NSB geological setting

The NSB originally continued to the southwest but was uplifted and eroded by the Plio-Pleistocene tectonic event that gave rise to the uplift of the Barisan Mountains. Tertiary rocks of the NSB are upturned and exposed along the leading edge of the uplift.

The Barisan uplift was caused by regional strike slip movement along the Great Sumatra Fault, a 1650-km-long dextral strike-slip fault zone which accommodates part of the oblique convergence of the subduction between the Indo-Australian and Eurasian plates off the Sumatran west coast. The Fault has given rise to wrench-related, compressional structures (thrusts, flower structures) within the NSB sediments along the margin of the uplift. The structural intensity rapidly decreases away from the leading edge of the uplift. The subduction zone is also giving rise to volcanism within the Barisan uplift. A recent volcanic cone can be seen within the Barisan Mountains to the south of Pase Block. Accordingly, the youngest rocks of the NSB exhibit various types of volcanoclastic input.

The southwestern block of the Pase PSC is situated adjacent to the leading edge of the Barisan uplift, topographically in the foothills of the mountains. Geologically, the southwestern block displays wrench related compressional structures that are often intense. Vertical bedding is not unusual at outcrop. By contrast, the northeastern block of the PSC is well removed from the uplift and exhibits a full sedimentary section with low-relief structures situated on the coastal plain.

5.5.2 Stratigraphy, Reservoirs and Seals

Stratigraphy, reservoir and seal development in the NSB are broadly as shown in Figure 7. In general terms the section above basement consists of an Oligocene to early Miocene rift sequence, represented by the Bruksuh and Bampo formations. Following the rift sequence was a marked early to middle Miocene marine transgression associated with the post-rift sag phase. Sediments of the marine transgression consist of a shallow marine limestone sequence the Peutu limestone overlain by the deep marine Baong shale. Towards the end of the Middle Miocene progressively shallower marine conditions prevailed, resulting in deposition of the deep to shallow marine Keutapang formation overlain by the shallow marine Seurula and the shallow marine to fluviatile Julu Rayeu. The development of the NSB was essentially terminated by the onset of the Barisan uplift during the Plio-Pleistocene.

Basement intersections in the Pase PSC are mostly of low grade metamorphics, often referred to a meta-greywacke. At Pase field the basement is fractured and can be considered a gas reservoir.

The **Bruksuh and Bampo Formations** were deposited in early rift stage, north-south oriented rifts and are present in most of the wells drilled to basement within the Pase PSC. Thickness varies from zero in B-1 and Pase A4 up to over 600 meters in Pase A2. The Pase field exhibits rapid variations in thickness, consistent with the localized nature typical of early rift sedimentation.

Sandstones are common in the Bruksuh formation. Porosity and permeability have been degraded by the deep burial prior to Barisan uplift. In Pase field the Bruksuh matrix porosities are mostly less than 5%, however, as with the basement and overlying Peutu the sandstones are also fractured, creating an economic reservoir. The Bampo formation, where developed, is all claystone.

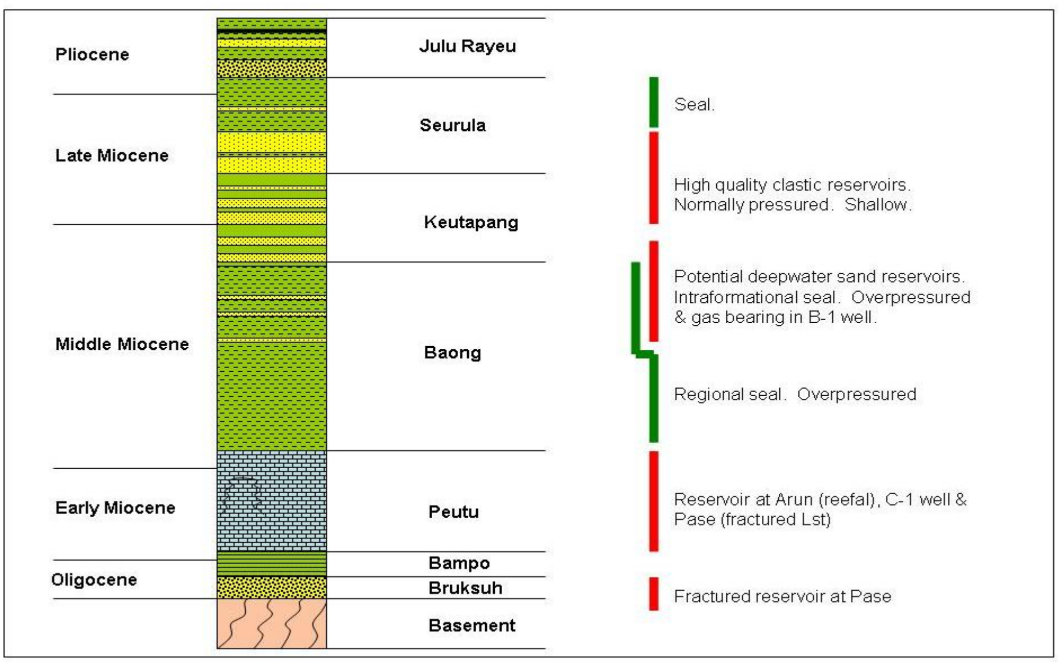

Figure 7 Generalized Stratigraphy

The **Peutu Limestone** is differentiated into two members on the basis of facies type. The Belumai member consists of slope and basinal carbonate facies. The Arun Limestone member consists of shelfal and reefal facies. The Arun Limestone facies forms the main, high quality, porous reservoir at Arun, Cunda, NSO and SLS B. The Belumai slope and basinal facies is the principal reservoir at Pase field where it exhibits low matrix porosity but is intensely fractured on a macro and micro scale.

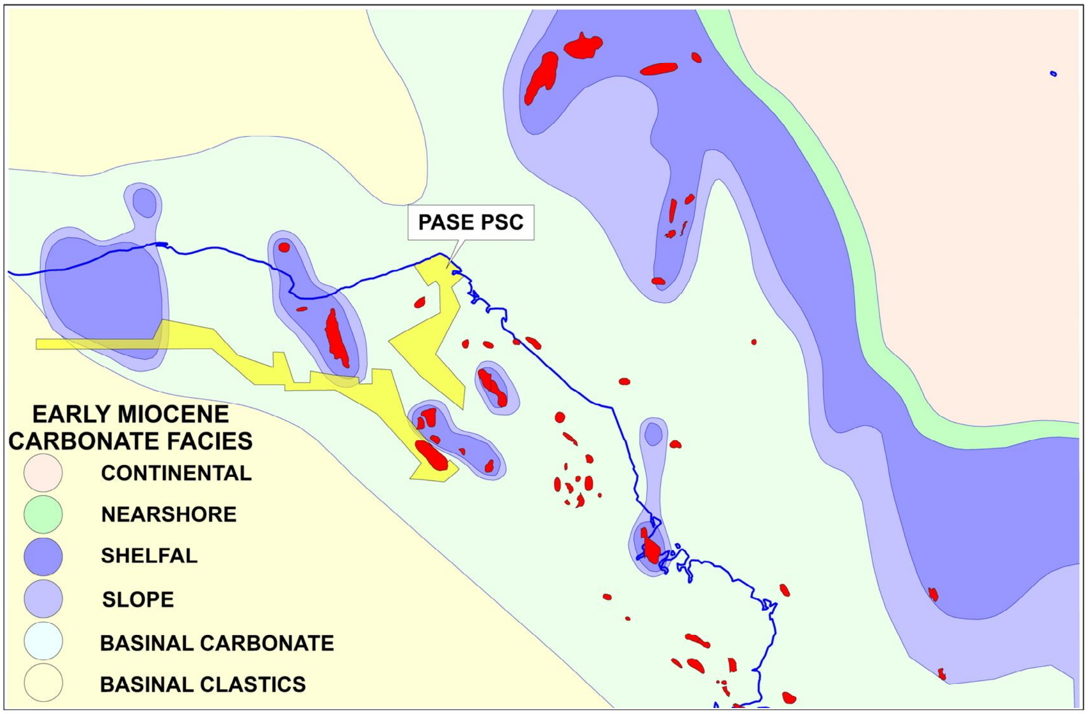

Figure 8 Peutu Limestone facies

Macro fractures in the Peutu Limestone are highly permeable. The micro fractures are less permeable, with reservoir behaviour transitional to that of the matrix porosity. A considerable amount of work was carried out by EOM to better understand the distribution of fractures. The conclusions from this work are broadly that fracture intensity increases with proximity to major fault systems and, more particularly, to areas where bends in the fault azimiths.

The **Baong Formation** was deposited in deep water during the middle Miocene transgression. In the vicinity of Pase PSC the Baong is mostly shale, forming an excellent regional seal over the Peutu, Bruksuh and fractured basement reservoirs. In the subsurface the shale is invariably over pressured. Wells targeting the Peutu have often required mud weights in excess of 16 ppg (e.g. C-1). The over pressure is the result of a combination of under-compaction due to rapid burial and unloading during the Barisan uplift. Well B-1 encountered a number of blocky sandstones within over pressured Baong Shale that appear to be deepwater turbidites. Thickness ranges from 10'-25'. One 20' sandstone at 10,300' appears to be gas bearing.

Deposition of the Baong Formation was initiated by a rapid sea level rise, such that the shoreline retreated well to the east onto the Malacca platform. Although the Baong in Pase PSC is mostly shale, there is evidence of deltaic and shallow marine deposition in the vicinity of the paleo-shoreline. An example is the Asahan sandstone on the Asahan arch at the southeastern end of the basin.

A lowstand of sea level has been interpreted to have occurred during the middle Baong period, giving rise to deposition of lowstand fans from the erosion and mass transportation of early Baong shelfal deposits. Transport direction appears to have been from east to west and it appears that some lowstand sand deposits may have reached as far as the northeastern block of the Pase PSC. It is thought that the thin Baong sandstones encountered in the Pase B-1 well are examples. Although much of the data has yet to be examined, such sandstones appear to offer a viable reservoir objective.

Another sea level rise occurred during the late Baong period, resulting in a cessation of lowstand fan deposition and a second phase of deltaic and shallow marine sedimentation close to the paleo-shoreline. Deposition in the vicinity of the Pase PSC at this time was mostly shale.

The **Keutapang and Seurula** Formations were deposited in a rapidly shallowing basin, resulting from slowing sea level rise and the rapid influx of clastic sediment from the incipient Barisan uplift. The sediments are predominantly deltaic and shallow marine sandstones and shales. In illustration of this, foresets of deltaic origin can be seen on seismic in the basal Seurula on numerous seismic sections in the NE block.

Well B-1 encountered interbedded sandstones and shales throughout the Keutapang and Seurula. One such 40' sandstone in the lower Keutapang at 7900' appears to be gas bearing. The log motif is coarsening upwards, suggesting it may be a marine bar sand. Plenty of shale is present throughout both formations, sufficient to provide intra-formational seal.

Little information is available to the author at present on the porosity and permeability of the Keutapang and Seurula sandstones in the Pase PSC; however the shallow depth of burial and clean gamma ray character suggests reservoir quality will be excellent.

5.5.3 Generation and Migration

Although the NSB is a proven prolific hydrocarbon province, hydrocarbon source rocks have not been positively identified. The most likely candidates are Bampo, Peutu and Baong shales. Measured total organic carbon in these formations however rarely exceeds 1%

Publicly available basin modeling indicates that much of the NSB is currently mature for the generation of thermogenic gas. The main source kitchen for much of Block B and the Pase Block is believed to be the Lhok Sukon trough which occurs immediately to the east of Arun and Pase fields.

The author has not sighted detailed modeling but it is thought that hydrocarbon generation in the Lhok Sukon trough commenced in the middle Miocene and peaked during the rapid loading due to deposition of the Keutapang and Seurula during the Late Miocene – Pliocene. Migration and structural development therefore appear to have been broadly synchronous. It is therefore likely that several phases of migration/ re-migration occurred before final accumulation.

Gas produced from Pase, Lhok Sukon and Arun fields has a carbon dioxide (CO2) content averaging 14%. The origin of CO2 is likely to have been from deep burial of limestones in the Lhok Sukon trough. It is known that CO2 is generated by the breakdown of carbonate minerals such as siderite ($FeCO_3$) and magnesite ($MgCO_3$) when the rocks have been heated above approximately 330°C. Such temperatures have certainly been reached in the deeper parts of the Lhok Sukon trough. CO2 contamination is therefore a risk with any exploration prospect in the Pase area. As an example, DST 2 conducted over the Peutu limestone in the C-1 well tested 0.29 mmscfd of gas that contained with 33% CO2 and 1390 parts per million of H2S (hydrogen sulphide).

5.5.4 Structural Geology

Structural development in the Pase PSC is primarily related to the Barisan uplift. Seismic foresets within the lower Seurula strongly suggest the presence of an emerging Barisan landmass to the southwest during the late Miocene. It is also apparent, however that the Seurula itself was subject to intense deformation, so clearly the Barisan tectonism continued until at least the late Pliocene.

The impact of Barisan tectonism on the Pase PSC sedimentary section is intense close to the leading edge of the mountain front but rapidly decreases to the northeast. The southwestern block of the Pase PSC is close to the leading edge and is intensely deformed over most of it's length. Typically the deformation consists of a relatively simple inversion of the competent Bruksah - Peutu section with some reversal of throw on old Eocene-Oligocene normal faults. Examples of this can be seen at Pase field and in the C-1 area. These rocks exhibit brittle behaviour with intense fracturing but little plastic deformation. By contrast, the overlying Baong has suffered intense, plastic deformation, including shale flowage, such that there is a complete disconnect from the Bruksuh–Peutu Structure. Baong shale swells occur almost continuously from south of the Pase Field to west of the C-1 well.

From Pase field to C-1 the shale flowage has caused the Baong, Keutapang and Seurula to turn uniformly upwards towards the Barisan leading edge, in places becoming almost vertical. This generally rules out any prospectivity in the post Baong section. However such is not the case further west. In the "Old Pase" field area and further west there are a number of Keutapang and Seurula anticlines that appear to have developed from a combination of wrench related compression and shale diapirism.

Structural development in the northeast part of the PSC is very different. The Barisan tectonism has created a series of broad, low relief folds.

5.6 Pase Field

5.6.1 Mapping

The principal asset of the PSC is the Pase gas field. The field was discovered in 1983 but not developed until 1998, when supplies of gas to the Arun LNG project began to decline. TPI have not yet had the opportunity to make it's own maps of Pase field. Figure 9 shows the EOM map that was current in EOM reports from 1998 until 2001. Figure 10 shows a second EOM map that was used in EOM's 2003 Pase Geomodel study. While they both show a broad structural high approximately 10 km long by 2.5 km wide, they have marked differences in the fault pattern. This attests primarily to the great difficulty that EOM experienced in imaging the structure seismically.

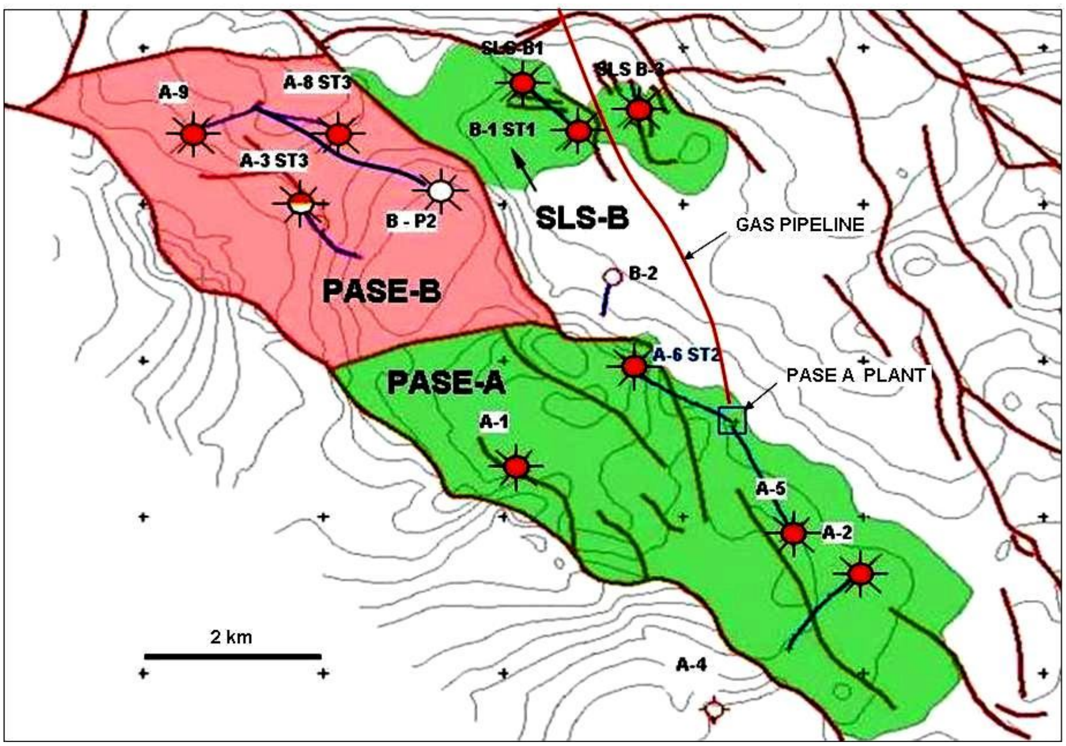

Figure 9 Top Peutu depth 1998-2000

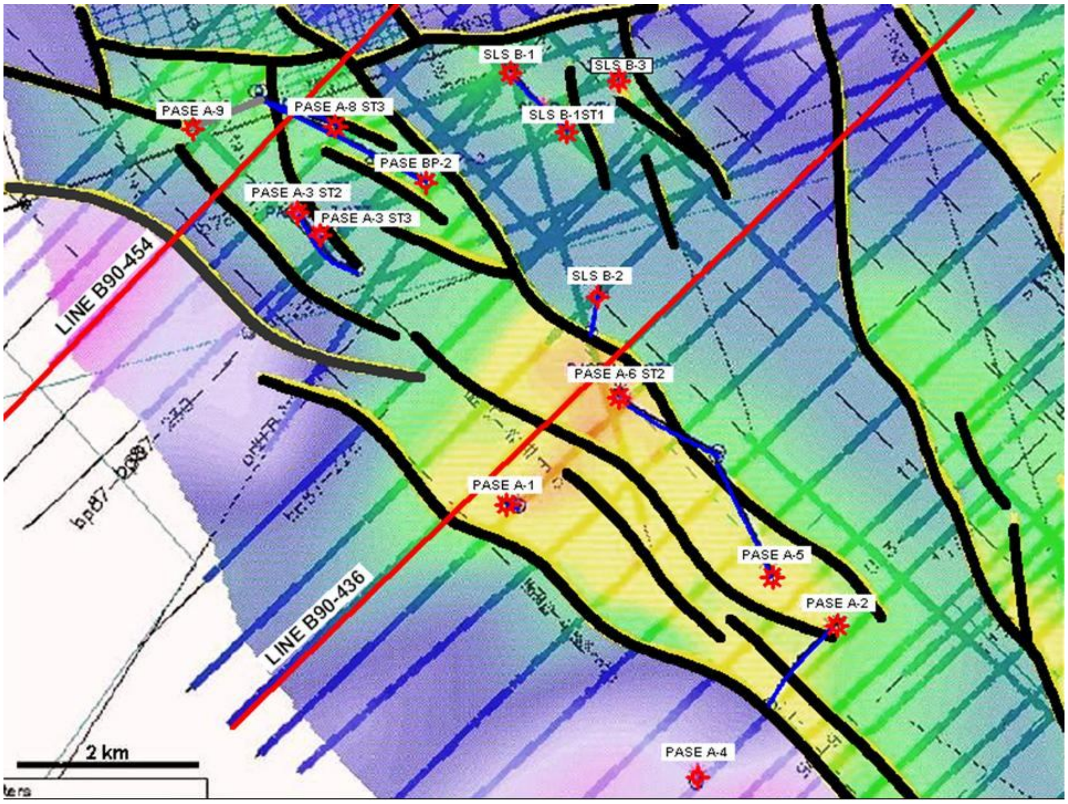

Figure 10 Top Peutu depth 2003

To overcome the seismic imaging problems, EOM proposed in 2000 to acquire a 3D survey. This never eventuated but the EOM report outlining the proposal presented a theory that some of the in-field 'faults' are in fact velocity induced migration 'busts'. Pase A-1 and A-6 intersected the top reservoir at similar subsea depth. The A-6 VSP ties the seismic with no shift whereas the A-1 VSP indicates a tie approx 150 millsecs above the event on the seismic. Incorrect migration has artificially depressed the top reservoir seismic event in the A-1 area. by approximately 500 feet! EOM were never able to solve such dramatic imaging and depth conversion problems.

In the author's opinion, little can be done to improve the accuracy of mapping, short of acquiring a 3D survey at great expense. Consequently, the depth prognosis for future drilling in the field for untapped compartments or attic reserves would carry significant risk as to the depth prognosis .

5.6.2 Drilling Results

The field discovery well, Pase A-1, encountered 126 feet of Peutu limestone before reaching a total depth of 7225 feet in meta-greywacke basement. The well tested a cumulative 38.6 MMCFG/D with a trace of condensate from the Peutu, Bruksah and Belumai Formations. No DST's were performed across the Basement. Lowest Known Gas (LKG) in the well was at 7200 feet tvdss with no indications of a Gas-Water Contact. The well was plugged and suspended as a gas well. EOM re-entered and sidetracked the well in 1998 for completion as a producer.

A three-well appraisal drilling programme was conducted during 1984 and 1985. Pase A-2, located 3.9 kilometers southeast of A-1, encountered 264' Peutu limestone and 106 feet of Bruksah Formation sandstone. This was much thicker than at A1, implying syn-depositional faulting. Three DSTs were successfully conducted for maximum rates of 23.9 mmscfd from the limestone and 22.5 mmscfd from the Bruksuh. Lowest Known Gas (LKG) in the well was at 7700 feet tvdss with no indications of a Gas-Water Contact in any formation. The Pase A-3 well was drilled 3.9 km to the northwest of A-1. The straight hole failed to reach the objective and an initial sidetrack was also unsuccessful. Second and third sidetracks penetrated to basement but failed to find any reservoir. The Pase A-4 well was drilled across a major fault to the southeast of Pase A-1. It encountered 23' of

Peutu on basement. All reservoirs appeared to be water wet. Top Peutu in A-4 was at 10085' tvdss, 2285' below lowest known gas in A-2.

The Pase appraisal drilling programme provided the following important information:

- The fractured reservoir was gas bearing over at least 3.9 km and thinned to the north
- The gas column extended from the highest point in A-1 at 6375' below sea level to the lowest point in A-2 at 7596' below sea level. A total of at least 1221'

Drilling on Pase field recommenced in late 1997 with drilling of production wells. A-1 was sidetracked and completed and new wells A-5, A-6 and A-9 were drilled. A-9 was unsuccessful and was sidetracked to become A-8. Pase BP-2 was drilled in 2002 for the development of the B (northern) compartment of the field. The well failed to flow at economic rates and has remained temporarily shut in. Following completion of development drilling the Pase field was proved to be gas bearing for over 8 km x 2 km with a gas column of at least 1221'. Table 2 shows the production performance of the field.

Well	Gas (bcf)	Cond (mmbbl)	Water (mmbbl)	Status
A-1ST	4.8	0.025	0.39	Shut in
A-5	18.4	0.13	0.34	Producing
A-6	151.8	1.038	6.36	Shut in
A-8	8.2	0.006	1.69	Shut in
Total	**183.2**	**1.20**	**8.79**	

Table 2 Pase production by well

5.6.3 Reservoirs and Production History

Various reserves studies of Pase field have been carried out. The author has sighted three studies:

1. DeGolyer & McNaughton Reserves certification January, 1989

- Predates production and main phase of seismic acquisition
- Proved 56.15 bcf , Probable 89.29 bcf
- Total 145.44 bcf net hydrocarbon gas

2. EOM 3D seismic proposal July 2000

- Pase A from material balance after partial production - 309 bcf proved
- Pase B most likely before commencement of production - 99.8 bcf

3. EOM geoscience model 2003

	Traditional Model (1)		Alternate Model (2)	
	GIIP	Phi eff	GIIP	Phi eff
Pase				
pore	**294.1**	**0.84**	**264.7**	**0.75**
frac	**338.6**	**0.97**	**325.5**	**0.92**
total field	**632.7**	**1.81**	**590.3**	**1.67**
Pase A				
pore	**243.3**	**0.90**	**219.9**	**0.76**
frac	**272.4**	**1.01**	**276.3**	**0.96**
total field	**515.7**	**1.91**	**496.3**	**1.72**
Pase B				
pore	**50.8**	**0.64**	**44.8**	**0.69**
frac	**66.2**	**0.83**	**49.2**	**0.75**
total field	**116.9**	**1.47**	**94**	**1.44**

Table 3 MPI Pase field reserves 2003

(*Phi eff refers to effective porosity. GIIP is gas originally in place*). The numbers indicate that the field has very large volumes but very low effective porosity. The volumes are roughly evenly split between the matrix porosity and the fractures.

The actual production performances for Pase A and B to end 2007 are shown in Figures 13 & 14. Both fields experienced sudden water breakthrough in about March, 2004. This is not unusual for fields with fractured reservoirs but, based on the 2002 decision to develop Pase B and the optimistic 2003 reserves study it was clearly not expected by MPI.

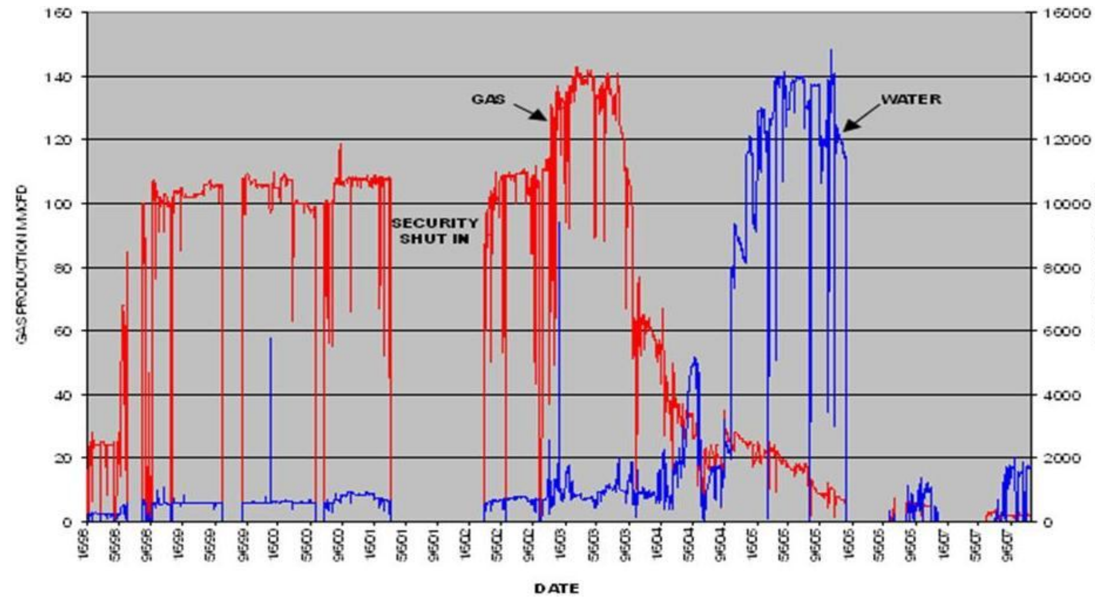

Figure 11 Pase A production history

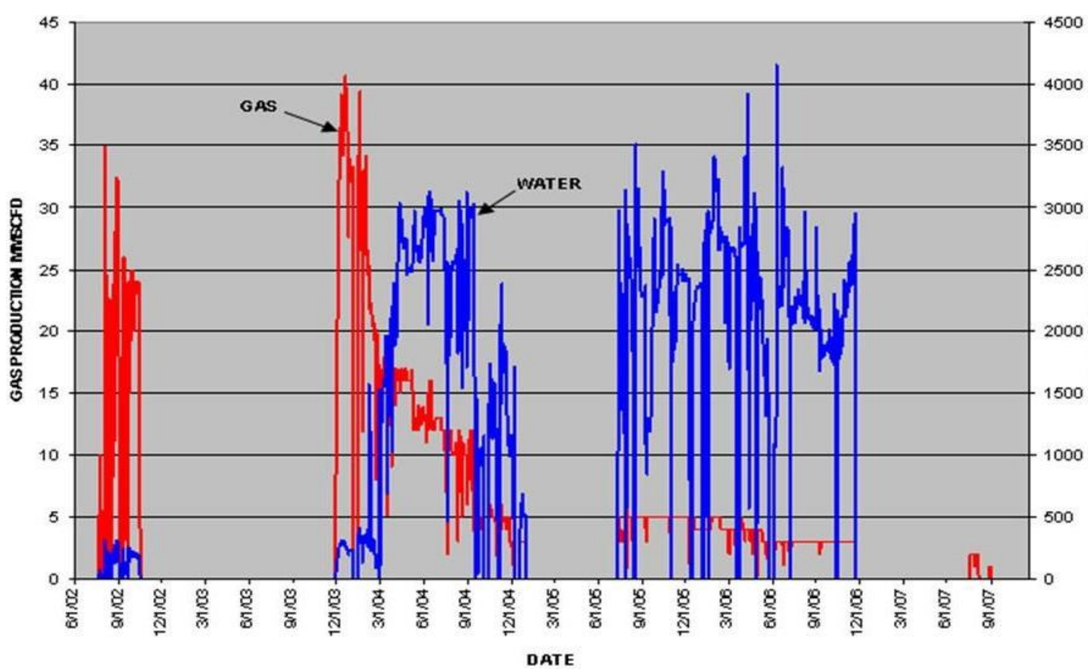

Figure 12 Pase B production history

MPI calculated about 325 bcf gas originally in place (giip) in the entire Pase fracture system. Cumulative production to date has been about 184 bcf. This represents about 57% of the 2003 EOM gas in place. The remaining 43% is probably partly in low permeability micro fractures, partly in attics, partly non-recoverable and partly in non-connected fractures.

As indicated by the EOM 2003 Geoscience model, gas in the Pase reservoir occurs in both the fracture system and the matrix. These reservoir components both have low porosity but grossly different permeability; very high in the fracture system and very low in the matrix system. It is also reasonable to assume that there is a component of the fracture system that is comprised of micro fractures that probably behave more like the matrix.

5.6.4 Reservoir Performance and Prediction

The field wide onset of water in 2004 indicates that the high permeability macro fracture system is now largely water bearing across the field. The exception would be in structural attics, although none are evident on the most recent EOM maps. In spite of this, the A-5 well, where the top Peutu reservoir is 662' deeper than at A-1, continues to produce at around 1.8 mmscfd plus 3000 bopd water. It is concluded that this well is producing gas from the matrix and micro fractures and water from the macro fracture system.

Given that MPI calculate some 275 bcf GIIP in the matrix and not much appears to have been produced it can therefore be anticipated that gas will continue to bleed from the matrix into the well bore at similar rates for the foreseeable future. The same can be said for the A-6 well which TPI plans to put back onto production. The reservoir in A-6 is 637' higher than in A-5 so performance should be at least as good. A-6 has been shut-in since December 2005 due to high water production. It is possible that the high pressure drawdown prior to shut-in caused water coning in the macro fractures. In the four years since shut-in it is likely that the water coning has subsided below the bottom of the well. If TPI brings the well back online without too much pressure drawdown then a period of gas production with no water can be expected. The duration of this period before water comes again may be a few days or a few months.

Since TPI took over the Pase field in June 2009 they have re-established production from Pase A-5 and have plans to bring A-6 back on line by resolving certain mechanical problems.

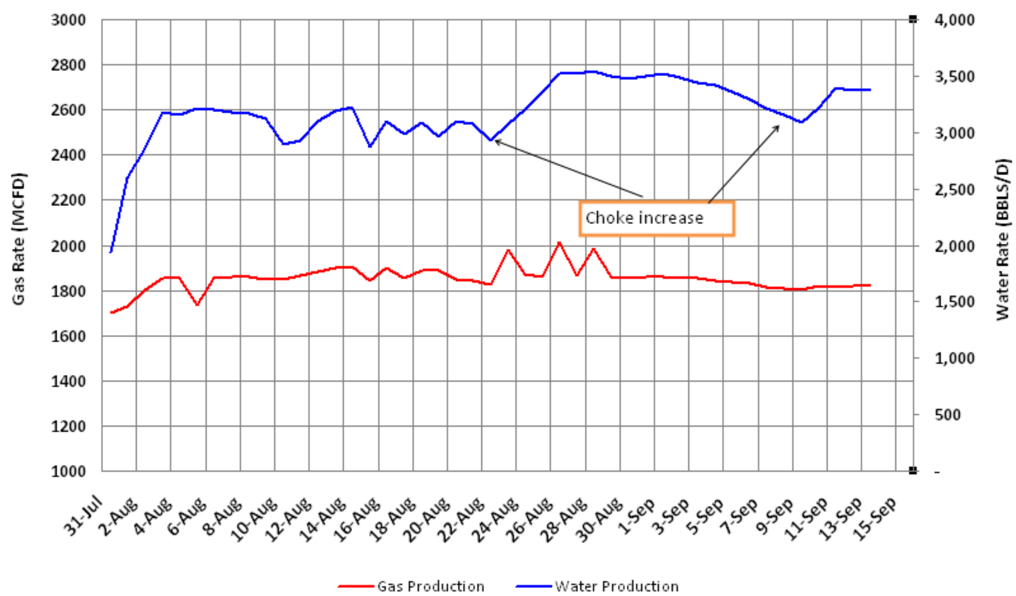

Figure 13 Pase A-5 TPI production

Gas production from A-5 has remained steady at slightly above 1.8 mmscfd for six weeks since coming back online. This is a relatively short history for the purposes of assessing future performance but the author is confident that it can be sustained, since the gas rate is in line with intermittent production from A-5 by MPI of 1-3 mmscfd since June 2007. Interruptions to MPI's production were due to their inattention to mechanical issues and not to reservoir performance.

An increase in choke size on 23rd August caused a 500 bpd increase in the water rate but no concurrent increase in the gas rate. This is indicative of the limited rate at which gas is bleeding into well bore from the surrounding matrix. In the author's view the gas pressure in the matrix remains much higher than in the macro fracture system, hence the continuous bleeding of gas from the low permeability matrix. The rate of matrix gas production can only be increased by increasing the pressure differential between the matrix and macro fractures. This would involve investment in a large scale project to produce massive amounts of water to lower the regional aquifer pressure. While theoretically feasible such a project could not be contemplated in the remaining life of the PSC.

TPI is entitled to production from the Pase field up to 11th February, 2011. As discussed in section 5.4 there is sufficient risk that the PSC will not be renewed that the author is not prepared to consider production potential beyond this time as a firm entitlement to TPI. For valuation purposes it is therefore necessary to make an estimate of future production from Pase field up to 11th February 2011.

Based on the foregoing it is reasonable to assume that A-5 will continue to produce at it's current rate or with gradual decline. It is further assumed that TPI brings the A-6 well back on stream on 1st November, 2009, with restricted drawdown. The well can be expected to produce at an average rate of 3 mmscfd for the first month followed by rapid decline to 2.0 mmscfd as the water production begins and gradual decline for the 13 months thereafter. This model is represented in Figure 14.

Based on this relatively conservative view, **the Pase field should produce approximately 1,802 mmscfd by the expiry date of the PSC**.

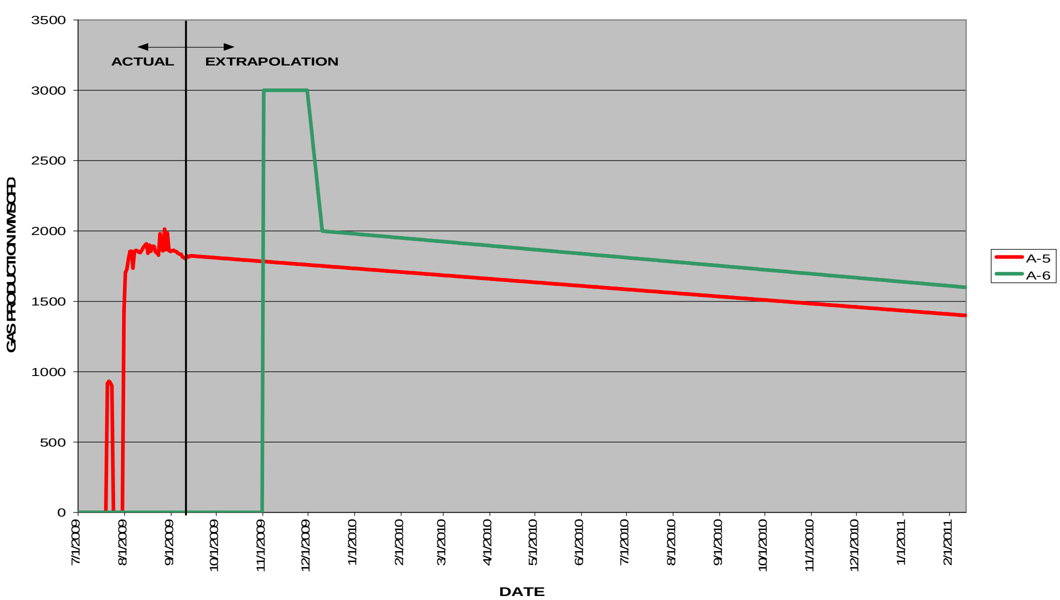

Figure 14 Extrapolation of TPI production

It is understood that TPI are also investigating the feasibility of bringing two additional field wells A-1 and A-8 back online. The author does not have specific information about these plans and therefore is unable to include possible future production from these wells in the above production model. Needless to say, however, if it is achievable in good time then the potential exists for additional production and revenue over and above the current assessment.

5.7 Exploration Potential

Further exploration of the PSC could only take place if the PSC was renewed following expiry on February 11th, 2011. The discussion below is therefore general in nature and is included only to give the reader a sense of potential exploration opportunities should the PSC be renewed.

At the time of writing this report TPI were still in the process of compiling and normalizing the existing seismic and well database prior to undertaking a detailed exploration study. For the purposes of this report the author has, in the interim, undertaken a brief review of the seismic data set.

EOM have held the Pase PSC since 1981. Prior to that the block had only been seriously explored by BPM before the war. EOM drilled three exploration wells, A-1, B-1 and C-1 during their tenure of the PSC. These wells only explored the deep, over pressured carbonate play, looking for large scale gas reserves to feed into the Arun LNG project. The shallower play has effectively not been explored since before WW2.

A variety of different play fairways appear to be present within Pase PSC. These include:

- Keutapang to Julu Rayeu structural play in the west of the PSC. Poorly covered by seismic and probably oil prone
- Peutu/ Bruksuh structural play in the southwestern block, between C-1 well and Pase field, and also in the far southeastern corner of the northeastern block. Almost certainly gas prone.
- A structural/stratigraphic play in the middle Baong and lower Keutapang in the northeastern block. Likely to be gas prone.

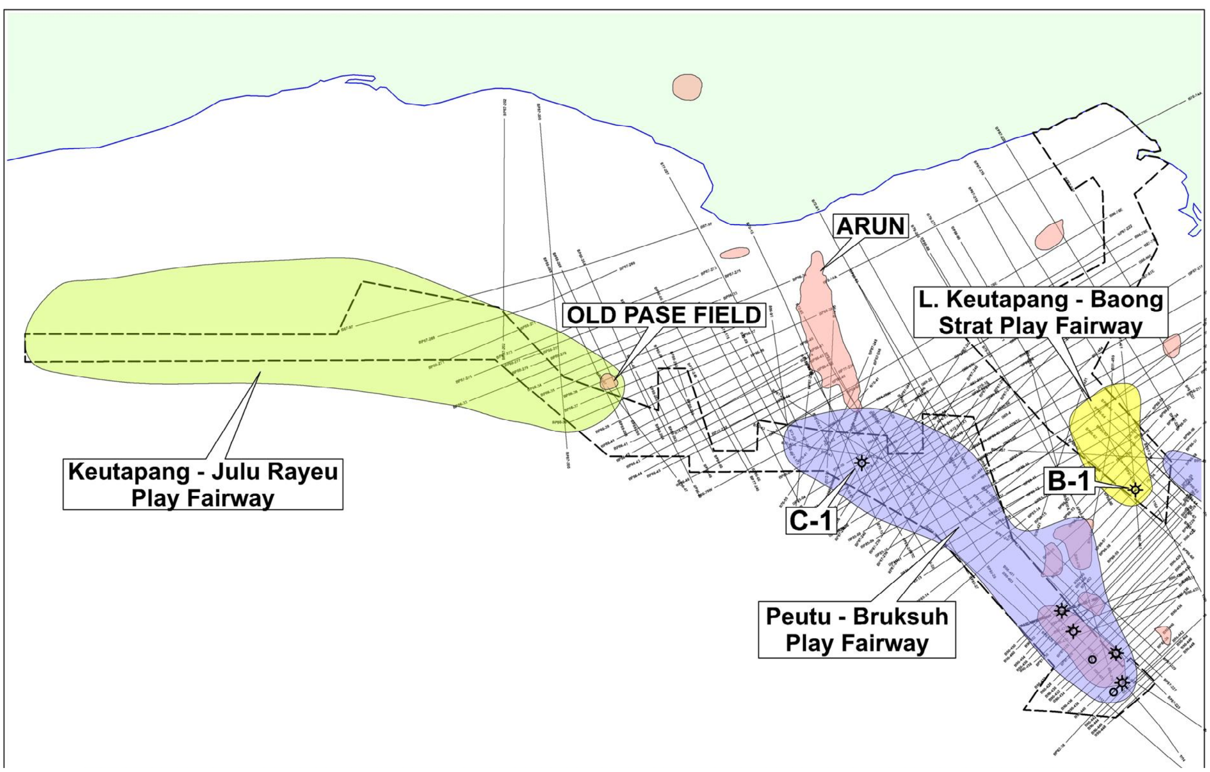

Figure 15 Play fairways and leads

The **Keutapang/Seurula structural play** is based firstly on the presence of oil in the pre-war "Old Pase" field and secondly on evidence from the sparse seismic grid of a number of anticlines in the subsurface. MPI report R70 contains some rudimentary maps over the "Old Pase" field area and concluded that the field contained 2.4 million barrels of remaining oil reserves. The report made the point that it was not MPI's policy to pursue such small reserves. There is no seismic coverage of the far western arm of the PSC but the Digital Elevation Model shown in Figure 2 suggests that similar geology may extend westwards from the seismic coverage. A number of one-line dip reversals were identified on existing seismic, giving encouragement that structural traps may be present. Exploration of this play clearly requires acquisition of additional 2D seismic.

The **Peutu/Bruksuh structural play** is defined by Pase field and the C-1 well. As indicated by Figure 8, it is unlikely that Peutu reefal development will be found within the block so the reservoir target for this play is likely to be fractured limestone, sandstone and basement as at Pase and C-1.

The C-1 well was drilled in 1988, some 5 kilometers to the south of Arun field. The target was reefal Peutu similar to Arun. The well drilled 5600' of Seurula and Keutapang, 5400' of over pressured Baong shale, about 1100' of Peutu limestone and reached TD at 12335' in the Bruksah, about 100' below the base of the limestone. Basement was not reached. Serious drilling problems due to heaving shale were encountered while drilling the Baong, necessitating two sidetracks. A massive lost circulation zone was encountered at 11839' within the Peutu, very likely due to fractures in the non-reefal limestone. 666 barrels of drilling mud were lost into the formation, probably damaging the reservoir. A test over the interval 11580'-11586' flowed 0.28 mmscfd after acid treatment. The gas contained 33% CO_2 and some H_2S.

C-1 appears to have intersected a gas accumulation of unknown size trapped in a reservoir of poorly understood potential. As with the Pase area, seismic depth imaging in the C-1 area is extremely difficult. Mapping in two-way time does not reveal any obvious trapping mechanism, so the extent of the accumulation can only be guessed at. On the negative side, however, the reservoir did not appear to be as intensely fractured as at Pase and the gas composition was much less favourable.

A brief seismic review suggests that there may be other structural nearby to C-1 offering similar, high risk potential.

A second negative factor is the extreme difficulty and expense of drilling through the over pressured Baong. C-1 well was drilled in 1988 and cost US$7.1 million. In 2009 an equivalent well would cost closer to $15 million.

Another second potential area for the Peutu/Bruksuh structural play is the fault bound anticline on the western, downthrown flank of Pase field, approximately 1.5 km east of Pase A-1 well. The structure is shown by the MPI map in Figure 9. The Pase A-4 well established that the fault block to the east of Pase field is in a different aquifer pressure regime to Pase and SLS., almost certainly meaning that the southwestern bounding fault of Pase field is sealing. Thus, there appears to be a valid trap. The main risks to this play are firstly that the seismic is of very poor quality and secondly that the reservoir is thin and thirdly that a well to test the feature would be difficult and expensive to drill

The middle Baong – lower Keutapang structural/stratigraphic play. Although failing to encounter reservoir development at the target Peutu level, the B-1 well nevertheless drilled through at least two thin sandstones within the overlying middle Baong and lower Keutapang that had high mud gas readings. Being relatively thin and small by the standards of MPI, these sandstones were never tested.

Examination of the seismic across B-1 fails to show any evidence of a structural trap. In fact the well was located in the middle of the southern extension of the Lhok Sukon syncline. Any gas would therefore need to be trapped entirely stratigraphically. In a general sense the lower Keutapang at B-1 appears to correlate on seismic to an interval of high amplitude reflections. It is possible that the high amplitudes may represent relatively thin gas bearing sands. The middle Baong sandstone occurs on the western margin of a packet of thin, high amplitude reflections that have the appearance of lowstand fan deposition down the axis of the Lhok Sukon Trough. The packet of amplitudes becomes thicker to the northeast of B-1. Any quantification of possible gas resources based on the foregoing observations is greatly premature. At the very least, detailed seismic reprocessing and petrophysical analysis would first need to be undertaken.

In summary, the lower Keutapang and Baong sandstones may be part of a larger stratigraphic trend extending to the northeast as shown on Figure 15. At this stage the trend is speculative. No specific leads are indicated since a complete review of the data set followed by seismic reprocessing and/or seismic acquisition is first required to build confidence in the theory.

6 Valuation

This report was commissioned to provide an independent valuation of the exploration and production assets of Triangle Energy Limited. These assets consist entirely of a 100% working interest in the Pase PSC. The interest is held by Triangle Energy Limited through it's wholly owned subsidiary Triangle Pase Inc (TPI). TPI owns a 100% working interest in the PSC. The Pase Block currently has production from the Pase gas field as well as a certain amount of exploration potential.

The valuation of TPI's 100% working interest in the Pase PSC is constrained by the expiry of the PSC on February 11th, 2011. As discussed in section 5.4 it is the Author's opinion that there is a moderate but significant risk that the PSC will not be renewed or not renewable on terms that are sufficiently attractive to TPI to justify the commitment.

Section 5.7 outlines what is considered by the Author to be a moderate risk/reward exploration potential for the Pase area. Exploration for oil and gas in a remote Indonesian onshore area such as Aceh requires careful planning and long lead times. There is therefore no possibility that any realization of the exploration potential could be achieved before PSC expiry. Consequently no firm value can be assigned to that potential.

The valuation of TPI is therefore limited to the net present value (NPV) of expected gas production up to PSC expiry. The Author's estimation of such production is described in Section 5.6.4 and illustrated by Figure 14.

The NPV has been calculated in accordance with the PSC revenue sharing scheme as shown in Figure 5 together with the production royalty payable to EOM. The calculation spreadsheet is shown in Table 4.

The Author concludes that the NPV of TPI's expected gas production up to February 11th 2011 is **Australian Dollars 8,800,000.00** (eight million eight hundred thousand Australian dollars). This valuation is at the market rates applicable at the date of this Report; 22nd September, 2009.

The following assumptions have been made in arriving at this valuation:

- The gas from Pase Field remains at or above US$8.00 per MMBTU until February 11th, 2011
- The heating value of dry gas metered upon leaving the Pase gas plant is at least 923 MMBTU per MSCF
- There is no significant condensate production
- Field water production and disposal remains manageable
- Production continues through to February 11th, 2011 without interruption due to mechanical failures
- Production operating costs are at or below the levels shown in Table 4
- TPI are able to bring the A-6 well online by 1st November, 2009

Valuation spreadsheet for expected TPI gas production to February 11th, 2009. (based on production extrapolation shown in Figure 14)

		2009				2010				2011
Production		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1
Gas Production	MMSCF			117.51	319.28	327.13	316.30	305.00	290.14	127.51
Gas Price	$/MMBTU	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00
Gross Revenue				868	2,358	2,416	2,336	2,252	2,142	942
First Tranche Petroleum				(174)	(472)	(483)	(467)	(450)	(428)	(188)
Cost Recovery										
ACTUAL RECOVERY				694	1,886	1,932	1,868	1,802	1,714	753
Unrecovered cost carried forward			7,693	8,359	7,833	7,260	6,752	6,310	5,956	5,603
Tax Computation:										
Contractor taxable Share FTP		-	-	117	318	326	315	304	289	127
Contractor Taxable Income		-	-	117	318	326	315	304	289	127
Government Tax Entitlement (56%)		-	-	66	178	183	177	170	162	71
Indonesia Share:										
BPMIGAS FTP share	32.5%	-	-	56	153	157	152	146	139	61
Government Tax Entitlement		-	-	66	178	183	177	170	162	71
Total Indonesia Share		-	-	122	331	340	328	317	301	132
Contractor Share:										
Contractor Share FTP		-	-	117	318	326	315	304	289	127
LESS Tax Entitlement		-	-	(66)	(178)	(183)	(177)	(170)	(162)	(71)
Cost recovery		-	-	694	1,886	1,932	1,868	1,802	1,714	753
Total contractor share		-	-	746	2,026	2,076	2,007	1,935	1,841	809
ExxonMobil Royalty	2.00%	0	0	17	47	48	47	45	43	19
Operating Cost		-	-	400	400	400	400	400	400	400
Contractor Quarterly Cash flow		-	-	328	1,579	1,628	1,560	1,490	1,398	390
Cumulative Cash flow to Contractor		**-**	**-**	**328**	**1,907**	**3,535**	**5,095**	**6,586**	**7,984**	**8,374**
Contractor NPV 10% US$				**$7,599.71**						
Contractor NPV 10% A$				**$8,836.87**						

Table 4. TPI valuation

7 Statements

7.1 Limitations

The author has primarily relied on data supplied by TPI. The information consisted of well reports, seismic data, maps, interpretation reports, financial records and legal documents. In the most part these were compiled by experienced and well-credentialed employees and consultants of ExxonMobil Corporation. The material was reviewed for it's quality, accuracy and validity and was considered to be acceptable. It is believed that the information received is both reliable and complete and there is no reason to believe that any material facts have been withheld. However, no warranty can be given that this review has taken into account all information, which a more extensive examination might reveal.

The opinions and statements in this report are offered in good faith and in the belief that such opinions and statements are not misleading.

7.2 Declaration

This Report has been prepared in accordance with the VALMIN Code 2005.

Roger Whyte has not had and, at the date if this report, does not have any relationship with Triangle Energy Limited or it's subsidiary TPI that could be regarded as capable of affecting the independent nature of this report. A fee will be received for the preparation of this report and is not contingent on any outcome to which this report might contribute. Roger Whyte will receive no other benefit for the preparation of this report.

7.3 Consent

Roger Whyte has given and has not withdrawn his consent to the publication of this report in the form and context in which it is included in the BDO Kendalls Independent Expert's report on the proposed transaction by Triangle Energy Limited to vend certain assets into Maverick Energy Limited for the consideration of Maverick shares.

7.4 Qualifications of the Author

Roger Whyte has a BSc degree (geology) from the Australian National University and a BSc degree (Hons) from the University of Tasmania. Mr. Whyte has over 30 years experience in the petroleum exploration and production industry, both within Australia and overseas, having worked for companies such as Shell Development (Australia) Limited, Union Texas Corporation, and Ampolex Limited. In addition, he has pursued a successful career as an independent petroleum industry consultant. His principal expertise is in geophysical interpretation and prospect evaluation. Roger has been an active member of the American Association of Petroleum Geologists since 1982 and is currently a member of the Southeast Asia Petroleum Exploration Society

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Roger Whyte

22nd September, 2009