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# SAGASCO RESOURCES LIMITED

## PERMIT T/RL1, BASS BASIN

## YOLLA PETROLEUM ENGINEERING REVIEW



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## ENCLOSURES

# 1 EXECUTIVE SUMMARY

One well has been drilled in the Yolla Field which is situated 205 km southeast of Geelong in the Bass Basin. The Yolla 1 well, drilled by AMOCO in 1985, recovered oil/condensate and gas from around 1830m and gas and condensate from around 2900m. The Yolla field has been investigated in several previous studies with the overall conclusion that field development may be economically viable depending on the results of appraisal drilling and the markets for gas. This conclusion is assumed valid and the economics of gas development were not studied further in this report.

This study investigated technical aspects of a Yolla development under various scenarios, including consideration of reservoir management, production profiles, facilities requirements and approximate costs for the gas development, along with some simplified economic analysis of possible incremental oil developments. It is intended that this document will form the basis for conceptual facilities studies to be undertaken in 1995. Key findings from this review are as follows:

1. A 600 bcf OGIP resource at 2900m would require approximately 14 producing wells with multi-zone chrome completions drilled within 5 km of a single platform. The base case scenario supplies a 25 PJ/year market with a 110% load factor for 10 years followed by a 7 year tail period (total 370 PJ). A sensitivity case with 180% load factor (still with 14 wells and 25 PJ/year market) requires a larger pipeline, larger offshore compressor, etc., and the 180% load factor can be maintained for only 9 years. In the 110% load factor scenario only 8 wells are drilled initially, with the remaining 6 in about Year 8 or 9, whereas all 14 wells would be required initially with a 180% load factor.

2. Refinements are developed herein to the factors for calculating reserves in the 2900m zone from volumetric OGIP estimates, to account for retrograde condensate dropout and likely reservoir pressure at abandonment. The recommended factors are 80% (reduced from 85% in R J Suttill's February 1993 reserves report) gas recovery factor and 63 (reduced from 68.6) stb of liquids recovered per MMscf of raw gas production.

3. Development of the reservoir (oil plus gas cap) at 1830m depth is probably sub-economic even as an incremental project to gas development, if the rock and fluid properties across the field are similar to Yolla 1. However, the oil column could be as thick as 23 metres and piggyback development could become attractive if reservoir properties improve significantly away from Yolla 1.

4. There is a possibility of oil reservoir(s) around 3000m depth. Analysis suggests that piggyback development could add incremental economic value to a Yolla gas project if there is an oil column thickness greater than 15 metres. Oil development would require compression to be offshore.

5. A number of conclusions and recommendations are made regarding the evaluation of the Yolla field during the appraisal stage and the focus of early facilities studies.

## 2 INTRODUCTION

This study into potential Yolla development under various scenarios included consideration of reservoir management, production profiles, facilities requirements and approximate costs for the gas development, along with some simplified economic analysis of possible oil developments. The scenarios investigated were:

**Case 1:** Develop gas in the 2900m zone with no compression offshore, with compression onshore from startup. No oil development.

**Case 1a:** As Case 1 plus development of hypothetical oil at 3000m.

**Case 2:** Develop gas in the 2900m zone with compression offshore. No oil development.

**Case 2a:** As Case 2 plus development of a single hypothetical oil leg on one of the three gas columns at 3000m.

**Case 2b:** As Case 2 plus development of the 1830m zone.

**Case 3:** Develop gas in the 2900m zone with no compression offshore, with more wells initially and delayed compression onshore. No oil development.

Several different studies had previously been performed by SAGASCO, AMOCO, the BMR and Thomas Petroleum Consultants (for SAOGC) since Yolla 1 was drilled by AMOCO in 1985. The well, in 79 metres of water in Bass Strait, 205 km from the Geelong coast, recovered hydrocarbons as follows:

**The N. aspersus Paleo Zone of the Eastern View Coal Measures Formation ("the 1830m Zone"):**

**DST 2:** Interval 1830-1835.2m KB. Flowed 2.2 MMscf/d of gas, RTSTM oil/condensate and 1675 bpd of water. The water was channelling from other interval(s) in the well behind the casing, where there was little or no cement.

**DST 2A:** Interval 1833.2-1833.8m KB (after several cement squeezes). Flowed 1.0 MMscf/d of gas, 302 stb/d of oil/condensate and no water.

**DST 3:** Interval 1813-1833.8m KB. Flowed 11.8 Mmscf/d of gas, 892 stb/d of oil/condensate and no water.

**The L. balmei Zone of the Eastern View Coal Measures Formation ("the 2900m Zone").**

**DST 1:** Interval 2809.1-2824.6m KB. Flowed 15.1 MMscf/d of gas, 580 stb/d of condensate and no water.

There has been no further drilling since Yolla 1. Subsequent work has focussed on marketing issues and more recently 3D seismic acquisition and interpretation. The drilling of one or more appraisal wells in 1995 is being considered by the Joint Venture.

The previous field studies have all concluded that development of Yolla for gas/condensate may be economically viable, depending on the results of appraisal drilling and the markets for gas. The 1985 Thomas report, by far the most detailed study to hand of the oil potential at 1830m, concluded that this zone would not support a stand-alone oil field development. However, since then there has been speculation as to the possible oil potential at 1830m (and potential oil legs at 3000m) based on the hypothetical oil-in-place upsides, the application of "new" technology such as horizontal drilling and the likelihood of piggybacking oil development incrementally onto a gas project.

The particular objectives of this study were as follows:

**1 Gas Development at 2900m**

1.1 Summarise a small number (3 in the end) of single platform development strategies for the gas at 2900m assuming 600 bcf OGIP in an area around Yolla 1 with a single platform drilling radius of about 5 km. Assume 25 PJ/year market with 110% load factor in the base case, and consider the effect of 180% load factor. The 600 bcf OGIP figure, in between current P and 3P estimates and close to the 2P estimate if the Yolla North Fault Block is considered, was chosen because it is close to the most likely estimate and is sufficient to make the project feasible, according to previous studies. Assume 200 km pipeline distance to shore, nominally to Geelong landfall. A landfall in Western Port Bay or on the north coast of Tasmania would not change the recommendations or conclusions significantly as the pipeline distance is similar.

Detailed economic evaluation of gas development was NOT an objective of this study.

1.2 Forecast surface pressures and production of gas, hydrocarbon liquids and water in each of the three gas development scenarios. These results may be used in conceptual facilities studies and economic analysis to refine development planning in parallel with the final decision on appraisal drilling.

1.3 Identify key issues in the gas development strategy that are particularly uncertain at this stage and that have a major impact. Consider all technical aspects including reservoir performance, well performance and surface facility philosophies. Identify possible means of addressing these key uncertain aspects, including evaluation strategies during appraisal drilling.

## 2 Oil Development at 3000m

Consider a hypothetical oil leg on the gas columns at 3000m depth (such a leg is possible downdip from Yolla 1) and determine how big the reservoir must be before a piggyback oil development adds incremental value to the gas project.

## 3 Oil Leg Development at 1830m

Evaluate the productivity, particularly the oil potential, of the 1830m zone.

## 4 General Oil Issues

Identify key uncertain issues in potential oil development. Identify possible means of addressing these issues.

# 3 CONCLUSIONS

## 1 Gas Development at 2900m

1.1 Appendix 1 and Table 6 summarise three cases for gas development of the 2900m zone assuming a 25 PJ/year market with 110% load factor and 600 bcf OGIP (Cases 1, 2 and 3 as defined in the Introduction). The 25 PJ/year rate is maintained for 10 years followed by a 7 year tail period (total around 370 PJ gas sales in the three cases). Going to a 180% load factor would require more wells drilled initially and much larger equipment (pipeline, compressor, etc.), and the 180% load factor could only be maintained for 9 years.

The amount of gas and liquids recoverable from the 2900m zone depends on many factors including the facilities configuration and minimum wellhead pressure. The calculated gas recoveries are 79% of OGIP with onshore compression and a 16" pipeline or 81.4% of OGIP with offshore compression. For reserves calculations from volumetric OGIP estimates, the recommended factors at this stage are 80% raw gas recovery factor and 63 stb of liquids recovered per MMscf of raw gas (average over the field life accounting for retrograde behaviour).

1.2 Tables 5.1, 5.2 and 5.3 summarise the forecasts of gas rate and wellhead pressure over the 17 year production life in Cases 1, 2 and 3. Table 1 summarises the initial in place gas composition for the 2900m zone that should be assumed for facilities studies. The liquids recovery (to be refined by detailed process calculations) is 68.6 stb per MMscf. The water production rate is expected to be 2 bbls per MMscf (condensation), corresponding to around 200 bpd. Higher water and/or hydrocarbon liquids production will occur if there is influx into the gas reservoirs from an aquifer and/or oil leg.

1.3 Key issues in the gas development strategy that are particularly uncertain at this stage and that have a major impact (apart from issues that are routinely investigated in any appraisal program) are discussed in Section 5.5. The key issues include:

- influx into the gas reservoirs from oil legs and/or aquifers.
- condensate dropout and fluid properties varying with depletion.
- interwell reservoir connectivity.
- size and cost of pipelines to shore.
- corrosion and hydrates in the pipeline to shore and other facilities.
- offshore platform concepts and cost estimates (capital and operating) in three cases of overall philosophy:
  - minimal facilities on platform; separation and compression onshore.
  - offshore water disposal and compression; $CO_2$ removal onshore.
  - offshore water disposal, compression and $CO_2$ removal.
- Onshore plant costs and final product streams: liquids suitable for refinery feed, sales gas within specification and possibly LPG.

## 2 Oil Leg Development at 3000m

Production of oil from 3000m, as an incremental project to gas development, will add significant economic value if oil viscosity is low as expected, if the reservoir quality is as good as interpreted from the Yolla 1 2900m DST (308 md permeability) and if there is an oil column thickness of 15 metres or more over an area of several square kilometres. In a 15 metre oil column, each horizontal well in a 1 km by 2 km area would produce around 2.7 MMstb with an initial oil rate around 3000 barrels per day. The approximate economic outcome for a five-producing-well development with $131 million initial capital would be $56 million after tax NPV at 10% (incremental to gas development with offshore compression).

Oil development requires compression to be offshore. Attempting to produce oil with compression onshore could mean tens of millions of dollars of extra costs plus flaring of tens of bcf of low pressure gas on the platform.

## 3 Oil Leg Development at 1830m

Incremental development of the 1830m zone would be sub-economic if the rock properties throughout the field are similar to Yolla 1 (30 md in the reservoir rock and tight rock above 1829.2m KB), even though the "oil column" may be as thick as 23 metres (from gas-oil contact at 1832.9m KB to 100% water level possibly as low as 1856m KB). In Yolla 1 the oil-water transition zone is interpreted to extend throughout the reservoir quality rock, with 4 metres of oil-gas transition at the top. There is no moveable oil below 1846m KB, with doubt about the producibility of oil between 1834 and 1846m KB. A horizontal well draining 2 square kilometres in a Yolla 1-type reservoir would be expected to produce only 1.4 MMstb of oil and 2.2 bcf of gas at a peak initial rate around 1000 bpd. The approximate economic outcome for a six well development with $86 million capital would be $24 million after tax NPV at 10% and 4.1 years undiscounted payback time (incremental to deep gas development with offshore compression). This is an upside case because efficient sweep by natural water drive is assumed.

In the 1830m zone away from Yolla 1 there is a possibility of better rock properties. A permeable interval with significant thickness above 1832.9m KB is likely to produce gas economically. Alternatively, good rock properties (e.g. 300 md) between 1832.9 and 1856m KB could result in a reservoir similar to that discussed in Conclusion 2: an effective oil column around 15m thick with each well making around 2.7 MMstb. Such an oil reservoir at 1830m would be even more economic than at 3000m because of lower well costs. Because of this upside potential, the 1830m zone should remain a secondary target in appraisal drilling.

## 4 General Oil Issues

The main uncertain issues in oil development would be addressed in any appraisal program. Special attention should be given to fluid sampling and analysis. On data obtained to date (though there could be surprises in appraisal drilling), Yolla cannot be developed economically on oil sales alone without a gas project.

# 4 RECOMMENDATIONS

## 1 Gas Development at 2900m

1.1 Strong consideration should be given to extended production testing of Yolla 2 or Yolla 3. The advantages of an extended test (perhaps one week flow followed by one week shut-in) compared to a routine DST (perhaps half a day flow and one day shut-in) would be:

- Define minimum accessed OGIP in the pool being tested.
- Help characterise barriers up to approximately 230 metres from the wellbore, depending on rock and fluid properties. (It may be advantageous to test a well within 230 metres of a reservoir barrier prognosed from 3D seismic).
- Determine the $H_2S$ content of the gas.

Extending one test by 13 days would cost 2 to 3 million dollars extra.

1.2 Appraisal wells should have logs and MDT run through any formation containing water that might influx into producing reservoirs. Planning to core or test specifically in an aquifer is unlikely to be justifiable, but may be considered.

1.3 Pre-Yolla 2 facility studies should assume gas production and wellhead pressure forecasts as in Table 5.1 (for cases with onshore compression) and Table 5.2 (for cases with offshore compression). The produced gas composition in Table 1 should be used for process calculations. In base cases the water production rate should be assumed at 2 bbls per MMscf, corresponding to around 200 bpd. Also the analysts must consider a contingency plan for each development strategy if water production for the gas wells turns out to be higher (say 2000 bpd) or if oil/condensate production is higher due to aquifer and/or oil leg influx into the reservoir. Contingency is needed to handle higher liquid processing rates and to prevent wells dying due to liquid loadup.

1.4 Special attention should be given to hydrocarbon fluid sampling and analysis during the appraisal program because the reservoir fluid is probably at saturation conditions and may be close to critical conditions.

1.5 An MDT tool (or equivalent) should be run in all appraisal wells especially for fluid sampling and because the definition of fluid contact depths is likely to be difficult.

1.6 An objective of 3D seismic interpretation should be to characterise faults and other barriers that could affect connectivity in the rock, both in the hydrocarbon reservoirs and in associated aquifers.

1.7 Before final development planning, aquifers associated with productive reservoirs should be mapped. The water in place effectively contributing to aquifer support should be estimated.

1.8 No further investigation is recommended into downhole development issues before Yolla 2 is drilled because they are sufficiently well defined in this report given the data available.

1.9 Issues that may be considered in pre Yolla 2 facility studies are discussed in Section 5.5 and include:

- Corrosion and hydrates in the pipeline to shore and other facilities.

- Onshore plant cost and final product streams: sales gas within specification, liquids suitable for refinery feed and possibly LPG.

- Offshore platform concepts and cost estimates (capital and operating) in three cases of overall philosophy;

    . minimal facilities on platform; separation and compression onshore.
    . offshore water disposal and compression; $CO_2$ removal onshore.
    . offshore water disposal, compression and $CO_2$ removal.

- Size and cost of pipelines to shore in these three cases.

## 2 Oil Leg Development at 3000m

There is no need for possible oil well production to be considered in detailed facility studies at this stage.

## 3 Oil Leg Development at 1830m

Do not credit economic value to the 1830m zone in Yolla at this stage because of the low permeability rock at Yolla 1. However, the zone should be considered a gas and oil target in appraisal wells because the rock properties may be better elsewhere in the field.

# 5 GAS DEVELOPMENTS AT 2900m

## 5.1 Hydrocarbons in Place and Required Wells in the 2900m Zone

Previous studies suggested that about 600 bcf OGIP is needed to justify a gas/condensate project in Yolla Field. In the latest OGIP report (Richard Suttill, February 1993), the figure mentioned was 400 PJ sales gas which corresponded to 618 bcf OGIP. OGIP estimates were as follows:

- 353.4 bcf 2P in the Y1 Fault Block (Figure 1) alone.
- A further 209.6 bcf that is 3P but would have been classed as 2P (being within a few kilometres of Yolla 1 and within the GWC contours interpreted from RFT data) except that it is in the YN Fault Block. The sum of 353.4 and 209.6 is 563 bcf.
- 791.4 bcf 3P in the Y1 Fault Block (an extra 438 bcf compared to 353.4 bcf 2P).
- Various other potential in the Yolla area taking the total 3P to 1055 bcf and the total 4P to 2058 bcf.

Based on these estimates, for the purpose of this study to consider gas development strategies, it is assumed that 600 bcf OGIP is contained within the Y1 and YN areas shown in Figure 1.

A further assumption is that wells approximately 1.5 km apart are sufficient to address this 600 bcf OGIP, resulting in the 14 conceptual well locations in Figure 1. Since these 14 wells are all within 5 km (an achievable lateral distance for a development well) of a possible platform location, a single platform development is assumed.

A major complication for gas development is that there is not a single reservoir in the 2900m zone. Rather there are 7 separate sandstone intervals that encountered gas in Yolla 1, as shown in Figure 2. One can only speculate about the rock properties away from Yolla 1, but there may be several reservoirs that will deplete separately at different pressures over the production timeframe. Dual and/or multiple tandem completions are likely in some wells, possibly all of them.

Another major complication is the high $CO_2$ content of the gas, around 19%, necessitating the use of corrosion resistant alloys in at least the downhole tubing (13 Chrome) and possibly some surface equipment. Corrosion inhibitor chemicals are likely to be injected on the platform.

The fluids recovered from Yolla 1 were very low in other inerts apart from $CO_2$. The $H_2S$ content detected by Draeger Tube in DST 1 was only 0.2 ppm. However, the duration of flow was only a few hours and $H_2S$ adsorbs on steel tubulars. Until more measurements are obtained, it is recommended that 20 ppm $H_2S$ be assumed in facilities studies.

The reservoir fluid recovered from the 2900m zone in Yolla 1 DST 1 was determined in the laboratory to be gas at reservoir conditions (4177 psia and 292°F at DST depth), with a dewpoint of 3698 psia. Given errors in measurements and sampling, the gas may be at saturation conditions in the reservoir. Downdip there may be an oil leg, or perhaps several oil legs in different reservoirs, or perhaps a sandstone not encountered at Yolla 1 that contains almost all oil down to the spill point.

Detailed laboratory analysis of the DST 1 fluid has been performed (Corelab 1985) to define the drop-out of retrograde condensate and the changing composition of produced fluid as the reservoir depletes. In final development planning such data will be needed, but at this stage it would be an unnecessary complication to consider varying fluid properties. Therefore only one fluid composition (the initial composition in Table 1) should be considered in facilities studies performed before Yolla 2 is drilled.

The Table 2 produced fluid composition is the instantaneous composition measured by Corelab when the pressure was depleted to 2715 psia. The condensate-gas ratio produced in the laboratory from this fluid (depletion from 3215 to 2115 psia) was 40.1 stb/MMscf from two surface separation stages (740 psig, 105°F and 50 psig, 90°F). This ratio compares to the DST 1 reported ratio of 38.4 stb/MMscf at rig conditions which may correspond to over 50 stb/MMscf through permanent production facilities. The 40.1 stb/MMscf result may also be compared to the cumulative average production of 39.7 stb/MMscf over a five-stage laboratory depletion from dewpoint pressure (3698 psia) to 1015 psia (around the final field pressure), as shown in Table 3.

Based on these comparisons, the fluids produced from the Table 2 composition are recommended to be used at this time as the average produced over the field life. The recoverable quantities of condensate and LPG (if a separate stream) per MMscf of raw gas production are in the order of 40 stb and 3.0 tonnes respectively. For reserves calculations from volumetric OGIP estimates it is recommended to assume a single liquid product stream at a yield of 63 stb per MMscf.

As far as aquifer support is concerned, the field is interpreted to virtually be sealed by faults (Figure 1). Therefore significant water influx is not likely during the production life of the field.

The initial "2900m Zone" reservoir conditions at average depth are assumed to be 4230 psia and 300°F, slightly higher than the values measured from DST 1 at the top of the zone.

## 5.2 Gas Rate and Pressure Forecast for 2900m Zone Wells (Base Case 110% Load Factor)

The forecast gas rate is assumed to be controlled by market demand of 25 PJ/year. Appendix 1 calculations show that the equivalent average raw gas production rate is 89 Mmscf/d. It is assumed that the field deliverability at any time during the 25 PJ/year contract must be at least 100 MMscf/d with one well off line (nominal 110% load factor in the base case).

The number of years of 25 PJ/year output depends on reservoir pressure decline (and hence OGIP), well productivity, the number of wells and the minimum wellhead pressure (WHP). The well productivity is summarised in Table 4 in terms of calculated WHP at varying reservoir pressure and production rate.

The number of gas production wells in each of the three cases, defined in Appendix 1, is assumed to be:

Case 1: Initially 8 wells. Finally 14 wells (discussed in Section 5.1).
Case 2: Initially 8 wells. Finally 14 wells.
Case 3: Initially 11 wells. Finally 14 wells.

A drilling rig will need to be brought back at least once during the production life for recompletions, so the last wells do not need to be drilled upfront. It is assumed that 8 wells are required in Cases 1 and 2 to obtain acceptable definition of the reservoirs (at least seven separate sands) and provide sufficient points for drainage and collection of data for long term planning, even if the initial productivity could be supplied from fewer wells. The initial numbers of wells in Case 3 is assumed to be 3 more (11) simply to enable a comparison of the benefits of drilling more wells and delaying compression - the cost of 3 wells is similar to the cost of compression.

The reservoir pressure at abandonment is calculated in Appendix 1 for each case, assuming deliverability at abandonment of 42 MMscf/d for the 14 well field. The corresponding raw gas recovery is 79.0% of OGIP in Cases 1 and 3 and 81.4% of OGIP in Case 2 which has a lower WHP. **The pressure and recovery conclusions are dependent on the implicit assumption that water influx into the reservoir will be insignificant, as expected because of sealing faults and thin sands encased in thick shales.**

The timing of compression and well drilling is detailed in Appendix 1, along with the year by year production forecasts. Tables 5.1, 5.2 and 5.3 summarise the forecasts of gas rate and wellhead pressure over the 17 year production life.

Unless detailed fluid property calculations are being performed based on the Table 1 gas composition, the hydrocarbon liquids recovery may be assumed in facilities studies to be 68.6 stb per MMscf of raw gas production.

The water production rate may be assumed in most cases to be 2 bbls per MMscf of raw gas production (condensation), corresponding to an average 178 bpd in Years 1 to 10. However, any field development must have a contingency plan if water production is higher due to aquifer influx, say 2000 bpd from the field, or if condensate/oil production is high due to influx from an oil leg.

### 5.3 Gas Rate and Pressure Forecast for 2900m Zone Wells (Sensitivity 180% Load Factor)

In this case also assume 25 PJ/year at average 89 MMscf/d, but the field deliverability at any time during the 25 PJ/year contract must be at least 160 MMscf/d with one well off line (180% load factor). Offshore compression is required. Assuming a total of 14 wells, the average well rate must be at least 12.3 MMscf/d to meet this deliverability criterion.

With offshore compression the minimum wellhead pressure is assumed to be 300 psi. The corresponding reservoir pressure to achieve a rate of 12.3 MMscf/d is 2065 psia according to FLOSYSTEM wellbore calculations with assumptions stated in Table 4. At 2065 psia reservoir pressure cumulative production is 307 bcf, achieved in 9.46 years at average 25 PJ/year.

In summary, the 25 PJ/year market could only be supplied at 180% load factor for 9 years. All 14 wells would be drilled upfront and of course the facilities (pipeline, compressor, etc) would need to be much larger than in the 110% load factor case.

### 5.4 Cost Estimates for Developing the Gas in the 2900m Zone

Though detailed economic evaluation of gas development is not an objective of this report, order of magnitude cost estimates are required to consider key aspects. The cost estimates are discussed in Appendix 1 and summarised in Table 6. As the author's expertise is primarily in petroleum engineering, the upstream capital and operating cost estimates are reasonable for this pre-appraisal stage (perhaps plus/minus 30%) whereas the downstream costs are quite unreliable.

The downstream costs are obtained mainly from very broad brush estimates made in 1994 with the assistance of Brown and Root. These estimates were based on general correlations with facilities costs in other fields, without a detailed consideration of Yolla processes. If accurate costs are required for pipelines, facilities and downstream operating, they should be obtained from another study.

## 5.5 Issues in Developing Gas at 2900m

As stated in the Introduction, an objective of this study was to identify key technical aspects of the gas development strategy that are particularly uncertain at this pre-appraisal stage. The main purpose of this exercise is to identify strategies during the appraisal phase.

### 5.5.1 Reservoir Issues

The major overall reservoir uncertainties, such as hydrocarbon in place, rock properties, pay thickness, structure, stratigraphy, well productivity and fluid contact depths, will be addressed by any appraisal program and require no discussion here. Some less obvious reservoir issues are:

**Influx into the gas reservoirs of oil from an oil leg or water from an aquifer.**

Such influx could reduce ultimate gas recovery by reducing expansion and could necessitate expensive artificial lift installation to prevent wells loading up with liquid. High water rates could increase corrosion and increase the cost of water handling and disposal.

There is no way of proving conclusively whether significant oil or water influx will occur without producing gas for many months, which is impractical at the appraisal stage. Therefore the development should have some contingency plan to cater for oil or water influx.

At the appraisal stage the 3D seismic should be used to characterise faults as accurately as possible. Before final development planning it will also be worthwhile to approximately map the extent of aquifers and estimate water in place. Appraisal wells should have logs and MDT run through any formation containing water that might influx into producing reservoirs. Planning to core or test specifically in an aquifer is unlikely to be justifiable, but may be considered. Aquifer testing could have a side benefit of obtaining water samples for Rw determination, though MDT samples would be less expensive.

**Condensate dropout and fluid properties varying with depletion**

As mentioned in Section 5.1, the gas in the 2900m zone appears to be at or close to saturation conditions and retrograde condensation is likely. Also the fluid may be near critical conditions and it may be difficult to establish whether there is liquid or gas phase in the rock at particular well depths. These aspects will affect fluid processing requirements over time and may significantly reduce condensate and LPG yield. Liquid dropout may also reduce the effective permeability to gas.

Carefully-planned fluid sampling at minimal drawdown is required during appraisal drilling. The fluids must then be analysed according to long term objectives. If there are separate reservoirs, the fluid properties of each must be established. The requirements to determine tricky fluid contact depths and possibly take many samples further emphasise the need to run the MDT tool.

**Interwell Reservoir Connectivity**

An objective of 3D seismic interpretation should be to identify faults and other barriers that could reduce interwell connectivity.

Strong consideration should be given to extended testing of Yolla 2 or Yolla 3 to characterise barriers using the pressure transient. For instance, a test with 7 days flow and 7 days shutin in a 300 md gas reservoir (similar to Yolla 1, DST 1) could detect a barrier up to 230 metres from the wellbore (Appendix 7 calculation). Such an extended test would also define minimum accessed OGIP. For instance, less than 10 psi depletion after 0.1 bcf production would indicate minimum 42 bcf OGIP in that pool. A side benefit of extended flow would be determination of the $H_2S$ content of the gas after initial adsorption on downhole tubulars.

One extended test may take about two weeks longer and cost 2 to 3 million dollars more than a short DST. The test might indicate poorer reservoir connectivity than expected, possibly affecting development economics and precluding any further work on the field.

**Potential to Increase Liquid Recovery by Gas Recycling**

There is insufficient data to consider this in detail. No further consideration is warranted until the field is appraised.

5.5.2 Development Well Issues

The major development well issues are not worth considering in more detail at the pre-appraisal stage, either because of lack of reservoir data or because the uncertainty does not have a major impact on the overall project. There is no reason to evaluate different numbers of wells or different completion strategies until further appraisal work. At this time it is reasonable to assume 13-Chrome completions with zonal shut-off capable of being operated by wireline, minimising the long term upstream operating costs of corrosion inhibition, coiled tubing and rigs.

At this stage artificial lift appears unlikely to be required for gas production wells. If future data suggest that high liquid production could cause wells to load up, some contingency could be made in development planning. The most obvious contingencies, gaslift or more surface compression, would be relatively straightforward in the offshore compression case. There is no obvious contingency without offshore compression if the wells load up due to liquid.

5.6.3 Surface Facility Issues

One major surface facilities issue is whether a subsea completion strategy or floating production system is preferable to a specially constructed platform. Brown and Root considered this issue in their 1994 report, which was against subsea completions and favoured a platform compared to a floating production system.

The following issues also warrant detailed investigation in the surface facilities study planned prior to Yolla 2 drilling:

**Size and cost of pipelines to shore**

This is such a significant issue, and relatively simple to investigate given the necessary software, that it is worthwhile for any facilities studies to check the preliminary conclusions of 12" line if compression offshore (without $CO_2$ removal) and 16" line if compression onshore. The case with compression and $CO_2$ removal offshore should also be considered. Consideration should be given to having separate lines for liquid and gas.

**Corrosion and hydrates in the pipeline to shore and other facilities**

The $H_2S$ content of the gas is unknown because adsorption on tubulars during Yolla 1 DST 1 resulted in only 0.2 ppm $H_2S$ in produced gas. How dependent is corrosion on the $H_2S$ content? Does this consideration lend weight to the arguments for a Yolla 2 extended flow test that would define $H_2S$ content?

How dependent are hydrates and corrosion on the water production rate? Would there be much difference at 2000 bpd (a high rate conceivable in the case of reservoir water influx) versus 200 bpd (the expected rate with condensation alone)?

Is there significant risk of pipeline corrosion leaks, necessitating multi million dollar repairs and long gas delivery delays, if all produced fluids go to shore in a single pipeline in the worst case of 30 years field life, 2000 bpd water production and $H_2S$ content at the top of the possible range?

How much is the corrosion potential reduced if water separation and compression are offshore, with negligible water in the pipeline. Does this significantly impact the capital costs (materials) or operating costs (corrosion and hydrate inhibitors) of the pipeline? Is there significant further reduction in corrosion potential if $CO_2$ is also removed offshore?

**Offshore platform concepts and cost estimates (capital and operating) in three cases of overall philosophy:**

a) **Minimal facilities on platform; separation and compression onshore.**

b) **Offshore water disposal and compression; $CO_2$ removal onshore.**

c) **Offshore water disposal, compression and $CO_2$ removal.**

This issue would constitute the major part of any facilities study at this stage.

**Onshore plant costs and final gas and liquid product streams**

Capital and operating cost estimates are needed for the onshore plant. Process calculations are also required for determination of the final product streams. Can the facilities readily be designed to produce one liquids stream suitable for refinery feed plus sales gas within specification?

# 6 OIL LEG DEVELOPMENT AT 3000m

## 6.1 Potential well productivity if there was an oil reservoir at 3000m

While no oil was encountered in Yolla 1 around 3000m depth, there could be oil legs to the gas reservoirs or possibly separate sands that contain almost all oil down to the spill point as discussed in Section 5.1. Appendices 2 and 3 detail two scenarios for developing a hypothetical oil reservoir that is 15 metres thick, approximately the minimum thickness for oil development to add economic value.

The assumed oil development is with horizontal production wells, rather that vertical/deviated, because of their higher productivity, higher oil recovery per well in a thin gas-cap-drive reservoir and lower tendency to cone gas.

Well productivity depends on many factors that are hypothetical in this case. The main assumptions (Appendix 2) are that the rock has good permeability (300 md similar to that interpreted from Yolla 1 DST 1 at 2820m depth) and that the oil has low viscosity (0.27 cp as estimated for Yolla 1 oil at 1830m depth). Geochemical analysis has shown that the Yolla 1 deep hydrocarbons (2820m) had the same source as the 1830m hydrocarbons, so the assumption of similar oil properties is reasonable.

After all the assumptions and application of the appropriate correlation (Appendix 2), a horizontal well production rate of 3000 bfpd is calculated. The estimated recovery is 25% of the oil in a 1 km x 2 km area, corresponding to 2.7 MMstb. In order to achieve this recovery, it is assumed that gaslift is required in the production wells and gas injection is required in the reservoir.

A reasonable field oil production forecast, assuming 5 producers and 2 injectors in a 10 square kilometre reservoir, results in 13.5 MMstb oil recovery in 9 years.

## 6.2 Incremental cost estimates for developing oil at 3000m in addition to gas development

High pressure gas is required on the platform because oil development is assumed to require gaslift and gas injection into the reservoir. As discussed in Appendix 2, the surface gas pressure required for gaslift is around 2500 psia, necessitating compression. Therefore with compression for gas development onshore, rather than offshore, the incremental cost of a high pressure gas line from shore to the platform would be incurred if developing oil. Moreover, without offshore compression all gas produced from the oil wells would be flared because of its low pressure. So two cases for oil development costs (Case 2a with and Case 1a without offshore compression), are considered (Appendices 2 and 3).

In Cases 1a and 2a the seven wells required for oil development are additional to the eight initially drilled as gas producers (Cases 1 and 2), so 15 well slots are required rather than 14. At the time require to maintain gas deliverability, the oil producers and gas injectors are converted to gas production.

The capital and operating costs (incremental to gas development) are itemised and summarised in Appendices 2 and 3.

### 6.3 Discussion of developing hypothetical oil at 3000m

Simplified incremental economics for Cases 2a and 1a are summarised in Appendices 2 and 3. In Case 2a with $131 million initial capital, after tax NPV is $56 million at 10% or $113 million undiscounted. In Case 1a with $147 million initial capital, after tax NPV is $29 million at 10% or $58 million undiscounted.

Oil development is much more attractive if compression is offshore. Indeed, apart from the higher costs and lost gas revenue, oil production may not be permitted by government authorities without offshore compression because of the flaring of many bcf of associated gas. It is therefore reasonable to conclude at this stage that oil development will eliminate the option of developing Yolla without offshore compression.

The incremental economic viability of Case 2a is reasonable though not outstanding. It is concluded that the assumed reservoir characteristics (15 metre oil column thickness with 300 md permeability and low oil viscosity) are approximately the minimum required for 3000m oil development. A reservoir with a thicker oil column could add outstanding value to Yolla Field.

# 7 OIL LEG DEVELOPMENTS AT 1830m

## 7.1 Hydrocarbons in place in the 1830m zone

Direct data on the hydrocarbons in place include:

- fluorescence in cuttings to 1856m KB
- fluorescence in sidewall cores at 1850 and 1855m KB
- significant gas peak on the mudlog down to 1857m KB
- logs (Figure 3) which alone are inconclusive but suggest a hydrocarbon-water contact around 1846m KB with a 12 metre transition zone to 1834m KB. The logs (eg MSFL) also indicate lack of permeability above 1829.2m KB. The sonic kick at 1830-1833m KB is probably due to free gas.
- RFT data (Appendix 4) which alone are inconclusive but which can be interpreted to indicate an oil-water contact in the vicinity of 1841m to 1856 KB, more likely at the deeper end of this range. (Note that the RFT tool will indicate oil gradient in an oil-water transition zone). The available data regarding the attempt to sample at 1832.5m KB suggest there is gas, not oil, there. Five attempted RFT points from 1807 to 1820m KB indicate no permeability.
- DST data (Appendix 5) which conclusively indicates oil without movable water at 1833.2 to 1833.8m and free gas somewhere in the interval from 1829.2 to 1833.2 m KB. The PLT in DST 3 showed no production above 1829.2m KB, supporting logs and RFT.

One core was cut in the 1830m zone, from 1838 to 1848m KB, but only 2.8 metres was recovered. The permeabilities are consistent with the in situ permeability of 34 md estimated from DST 2A (1833.2 - 1833.8m KB):

| Core Depth (m KB MD) | Ambient Horizontal Permeability (md) |
|---|---|
| 1845.6 | 75 |
| 1845.9 | 17 |
| 1846.2 | 11 |
| 1846.5 | 65 |
| 1846.8 | 51 |
| 1847.1 | 37 |
| 1847.4 | 42 |
| 1847.7 | 204 |

All these data are consistent with the theory that there may be a 100% water level at 1856m KB with a large water-oil transition, and an oil-gas transition zone from around 1833m KB (the gas-oil contact estimated in 1985 was 1832.9m KB, a good value for the deepest point with movable gas) up to the top of permeability at 1829.2m KB. Such transition zones are reasonably consistent with the 30 md permeability. For instance Wright and Wooddy presented a plot of their 1955 data (Figure 4) that suggests the following capillary pressures.

| Water Saturation | Capillary Pressure in Literature 30 md Rock (psi) | Corresponding h (m) by Calculation Below |
|---|---|---|
| 0.74 | 5 | 3.8 |
| 0.63 | 10 | 7.5 |
| 0.59 | 15 | 11.3 |
| 0.57 | 25 | 18.8 |
| 0.51 | 50 | 15.0 |
| 0.48 | 75 | 56.3 |

h = height in metres above 100% water level in the reservoir corresponding to capillary pressure P psi

= 0.4 P/(1.42 - 0.884)

= 0.75 P

where 1.42 psi/m and 0.884 psi/m are the respective water and oil gradients (Appendix 4) and 0.4 is the approximate ratio of interfacial tension at reservoir conditions compared to laboratory conditions.

There is no reliable direct data on the Yolla 1 fluid saturations. The number originally estimated from logs in the 1833.1 to 1833.8m KB interval was 0.40 oil saturation (1985 Thomas Report interpretation of DST 2A). The following order of magnitude saturation profile is consistent with this:

| Depth (m KB) | Interval h (m) | Water | Oil | Gas | Oil Saturation times h |
|---|---|---|---|---|---|
| 1856 | - | 1.0 | 0 | 0 | - |
| 1856-1846 | 10 | 0.7 to 1.0 | 0 to 0.3 (immovable) | 0 | 1.5 |
| 1846-1844 | 2 | 0.65 | 0.35 | 0 | 0.70 |
| 1844-1841 | 3 | 0.5 | 0.5 | 0 | 1.5 |
| 1841-1836 | 5 | 0.42 | 0.58 | 0 | 2.9 |
| 1836-1832.9 | 3.1 | 0.40 | 0.58 | 0.02 (immovable) | 1.798 |
| 1832.9-1829.2 | 3.7 | 0.39 | 0.31 | 0.3 | 1.147 |
| | | | | | **Total = 9.545m** |

The average porosity is 0.25, the net to gross ratio is 0.85 and the formation volume factor for the oil is 1.617 rb/stb, resulting in the following oil in place.

OOIP per unit area = 6.2898 bbls per $m^3$ x (9.545m) x 0.25 x 0.85/1.617

= 7.890 stb per square metre

= 7.890 MMstb per square kilometre

The area of the oil reservoir has not been appraised, but from seismic interpretation could be tens of square kilometres resulting in possible OOIP of over 100 MMstb. Unfortunately most of this oil is immovable and oil recovery is only marginally economic as discussed in Section 7.3, fundamentally due to the low permeability of the rock.

The free OGIP can be estimated using the formation volume factor of 0.00594 rcf/scf:

Free OGIP per unit area = (0.02 x 3.1m + 0.3 x 3.7m) x 0.25 x 0.85/0.00594

= 41.93 scm per square metre

= 1.481 bcf per square kilometre

If the reservoir extends for tens of square kilometres with this free gas content, the OGIP could be tens of bcf.

The fluid properties in the 1830m zone are summarised in Appendix 5. Original reservoir conditions were 2710 psia and 209°F at 1832.7m KB.

## 7.2 Well productivity in the 1830m zone

Assuming reservoir as deduced at Yolla 1 (Section 7.1), ultimate recovery would be maximised by producing from the top of the pay (up to 1829.2m). There would be minimal residual trapping of retrograde condensate or smeared oil in the gas cap if the deduced fluid saturations are correct, because there is already 31% oil in the gas cap. Also in such a thin low permeability reservoir it would not be feasible to place perforations or a horizontal drainhole in the oil and avoid depletion of the gas cap, as evidenced by coning in DST 2A.

The best oil recovery would be obtained if aquifer drive was strong enough for water to displace oil up to the top of the reservoir. Such aquifer support is doubtful, but will be assumed for the purpose of this report. Artificial lift would be required, and gaslift is assumed. The assumed final reservoir conditions are 2210 psia (depleted by 500 psi), with the following saturations:

| Depth (m KB) | Interval h (m) | Saturation Water | Saturation Oil | Saturation Gas | Oil Saturation times h | Gas Saturation times h |
|---|---|---|---|---|---|---|
| 1856 | - | 1.0 | 0 | 0 | - | - |
| 1856-1846 | 10 | 0.7 to 1.0 | 0 to 0.3 (immovable) | 0 | 1.5 | 0 |
| 1846-1844 | 2 | 0.65 | 0.30 | 0.05 | 0.6 | 0.1 |
| 1844-1841 | 3 | 0.605* | 0.345 | 0.05 | 1.035 | 0.15 |
| 1841-1836 | 5 | 0.581* | 0.369 | 0.05 | 1.845 | 0.25 |
| 1836-1832.9 | 3.1 | 0.575* | 0.375 | 0.05 | 1.163 | 0.155 |
| 1832.9-1829.2 | 3.7 | 0.4 | 0.5 | 0.1 | 1.85 | 0.37 |
| | | | | | **Total = 7.993m** | **Total = 1.025m** |

* Assume 70% volumetric sweep by water in these intervals and 0.65 end point saturation.

With these assumptions and final formation factors of 1.49 rb/stb oil and 0.007265 rcf/scf (0.2057m$^3$/Mscf) gas, the hydrocarbons remaining in a one square kilometre area after successful depletion are:

Reservoir Oil MMstb = 6.2898 x 0.25 x 0.85 x 7.993/1.49 = 7.170 MMstb
Reservoir Free Gas bcf = 0.25 x 0.85 x 1.025/0.2057 = 1.059 bcf

Based on difference from initial hydrocarbons in place (Section 7.1), production of reservoir oil and free gas would be 0.720 MMstb and 0.422 bcf respectively.

The reservoir oil is assumed to contain 1030 scf/stb of dissolved gas and free gas is assumed to contain 40 stb/MMscf of condensate. Therefore for a well draining one square kilometre:

| | | |
|---|---|---|
| Oil/condensate production | = | 0.720 + 40 x 0.422/1000 = 0.737 MMstb |
| Total gas production | = | 0.422 + 1030 x 0.72/1000 = 1.164 bcf |

Thomas Petroleum Consultants' 1985 estimate of oil recovery was 0.9 MMstb from each well accessing a 175 acre (0.71 square kilometres) drainage area, or 1.27 MMstb per square kilometre. Their estimate is higher because of incorrect oil formation volume factor (7.2% lower than the laboratory value measured later) and the optimistic assumption of 20-25% recovery factor from a low permeability 19-28 feet oil column. Their calculation procedures would have resulted in 0.737 MMstb per square kilometre if they had used the correct formation volume factor and 15% recovery factor.

The production rate of a vertical/deviated well is assumed to be 500 bfpd as used in the 1985 Thomas Report and consistent with DST 2A. Assuming an average oil/condensate production rate of 250 bpd over the well life, the time to recover 0.737 MMstb would be 8 to 9 years.

A horizontal well may be assumed to drain double the area of a vertical well, or two square kilometres. Water drive sweep efficiency would be lower than the 70% assumed above because of the larger area and because the horizontal drainhole may be several metres from the top of the reservoir. Therefore the recovery would be slightly less than twice that for a vertical well. Reasonable estimates are 1.4 MMstb and 2.2 bcf, still recovered in 9 years because of the higher well productivity. The production rate of a horizontal well would be about double that of a vertical well, or 1000 bfpd.

**Note:** The above oil recovery numbers are optimistic particularly because efficient sweep by natural water drive is assumed.

## 7.3 Discussion of developing the 1830m zone

Development of the 1830m zone is evaluated as Case 2b, incremental to Case 2 gas development with offshore compression and analogous to Case 2a for deep oil development. It is assumed that the 1830m zone has rock and fluid properties similar to those at Yolla 1, over a 12 square kilometre area. The reservoir can be drained in 9 years by 6 horizontal wells in the 6 well slots that are available in Case 2.

The 13.2 bcf gas production from the 6 horizontal wells (2.2 bcf each) is not assigned any value as it is assumed to be mainly used for incremental fuel. Even if there were a few bcf incremental gas, the NPV value of this gas would be very low because it would not add to sales until years 11 to 17 (because the market demand in the first 10 years is met by deeper gas).

The capital and operating costs and simplified economics (incremental to Case 2 gas development) are summarised in Appendix 6. With $86 million initial capital, after tax NPV is $24.2 million at 10% or $57.1 million undiscounted. Undiscounted payback time is 4.1 years from the start of oil production.

The economic viability of Case 2b is marginal, especially since the oil production forecast could be considered optimistic. The Joint Venture would be unlikely to proceed with such a project unless significant upside potential was identified. Based on Yolla 1 data there is little upside, at least compared to total costs for Yolla development of $400 million plus, and so at this stage economic value should not be credited to the 1830m zone. However the zone should be a gas and oil target in appraisal wells because the rock properties may be better elsewhere in the field. Higher permeability (eg 300 md similar to the Case 2A reservoir) could double the oil reserves per well, in which case a multiwell piggyback oil project could add in the vicinity of $100 million to the project NPV.

# TABLE 1

## INITIAL GAS COMPOSITION IN YOLLA "2900m" GAS ZONE

**Note:** This initial composition should be used for facilities studies.

| COMPOUND | MOLE PERCENT |
|---|---|
| Hydrogen Sulphide | 0.00 (**) |
| Carbon Dioxide | 18.86 |
| Nitrogen | 0.20 |
| Methane | 63.87 |
| Ethane | 7.64 |
| Propane | 3.75 |
| iso-Butane | 0.65 |
| n-Butane | 1.04 |
| iso-Pentane | 0.38 |
| n-Pentane | 0.39 |
| Hexanes | 0.54 |
| Heptanes | 0.74 |
| Octanes | 0.55 |
| Nonanes | 0.34 |
| Decanes | 0.21 |
| Undecanes plus | 0.84 |
| | 100.00 |

Molecular weight of heptanes plus: 137
Density of heptanes plus: 0.793

### Total "Plant Products" in the above fluid:

| | Gallons in 1 MMscf of Raw Gas | BBLS per MMscf |
|---|---|---|
| Ethane C2 | 2038 | 48.5 |
| Propane C3 | 1029 | 24.5 |
| Butanes C4 | 539 | 12.8 |
| Pentanes plus C5+ | 1963 | 46.7 |
| Assumed Recoverable Liquids = 100% of C5+ +75% of C4 +50% of C3 | N/A | **68.6** |

Approximate recoverable liquids are 68.6 stb per MMscf of raw gas produced.

** Until measurements are obtained during extended flows, assume 20 ppm $H_2S$ in facilities studies.

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# TABLE 2

## TIME AVERAGE PRODUCED FLUID COMPOSITION TO ASSUME FOR YOLLA "2900m" GAS ZONE

**Note:** The gas composition changes over field life due to retrograde behaviour. This produced fluid composition, measured in the laboratory after depletion to 2715 psia at 292°F, is a representative average.

| COMPOUND | MOLE PERCENT |
|---|---|
| Hydrogen Sulphide | 0.00 (**) |
| Carbon Dioxide | 18.91 |
| Nitrogen | 0.22 |
| Methane | 64.40 |
| Ethane | 7.63 |
| Propane | 3.72 |
| iso-Butane | 0.59 |
| n-Butane | 0.99 |
| iso-Pentane | 0.35 |
| n-Pentane | 0.36 |
| Hexanes | 0.51 |
| Heptanes | 0.71 |
| Octanes | 0.51 |
| Nonanes | 0.30 |
| Decanes | 0.18 |
| Undecanes plus | 0.62 |
| | 100.00 |

Molecular weight of heptanes plus: 129
Density of heptanes plus: 0.784

### Total "Plant Products" in the above fluid:

| | Gallons in 0.24781 MMscf of Raw Gas | BBLS per MMscf |
|---|---|---|
| Ethane C2 | 504 | 48.4 |
| Propane C3 | 253 | 24.3 |
| Butanes C4 | 126 | 12.1 |
| Pentanes plus C5+ | 430 | 41.3 |
| Recoverable Liquids to Assume for Reserves = 100% of C5+ +75% of C4 +50% of C3 | N/A | **62.53** |

For reserves, assume recoverable liquids of 63 stb per MMscf of raw gas produced.

** Until measurements are obtained during extended flows, assume 20 ppm $H_2S$ in facilities studies.

## TABLE 3

RESULTS OF LABORATORY DEPLETION OF 2900 m FLUID (YOLLA 1 DST 1)
(from Corelab Report, 1985)

Note: The separator samples from DST 1 were recombined in the reported ratio to form "reservoi fluid," which had a dewpoint of 3698 psia at 292 degs F. A depletion experiment was cond on the reservoir fluid at 292 degs F, starting at 3698 psia and going in 6 stages: 3215, 271 2105, 1515, 1015 and 515 psia. The separation conditions for the produced fluid at each reservoir pressure stage were: 1st Stage at 740 psig & 105 F; 2nd Stage at 50 psig & 90 F

The results, as summarised below for the relevant pressure ranges, are reported on a normalised basis per MMscf of original fluid.

**Recoverable condensate :** Assumed = Liq ex 1 + Pentanes plus in Gas ex 1 (42 gals/bbl).
**Recoverable LPG:** Assumed = (Propane + Butane in Gas ex 1)
(Propane at 0.0022 tonne per gallon and butane at 0.0023 tonne per gallon)

**First range considered: From dewpoint (3698 psia) to 1015 psia**

Data:

| Separator stage | Gas recovered (MMscf) | Stock tank liquid (bbls) | Propane (gals) | Butanes (gals) | Pentanes plus (gals) |
|---|---|---|---|---|---|
| Liq ex 1 | 0.00222 | 23.09 | - | - | - |
| Gas ex 1 | 0.69485 | - | 674 | 294 | 212 |
| Gas ex 2 | 0.01139 | - | 40 | 22 | 15 |

Calcs: Total gas recovered = 0.00222 + 0.01139 + 0.69485 = 0.70846 MMscf
Recoverable condensate = 23.09 + 212/42 = 28.14 stb = 39.7 stb per MMscf of produced g
Recoverable LPG = (674*0.0022 + 294*0.0023) = 2.159 tonne = 3.05 tonne/MMscf

**Second range considered: From 3215 to 2115 psia**

Data:

| Separator stage | Gas recovered (MMscf) | Stock tank liquid (bbls) | Propane (gals) | Butanes (gals) | Pentanes plus (gals) |
|---|---|---|---|---|---|
| Liq ex 1 | 0.0009 | 9.72 | - | - | - |
| Gas ex 1 | 0.28671 | - | 277 | 121 | 84 |
| Gas ex 2 | 0.00472 | - | 16 | 9 | 5 |

Calcs: Total gas recovered = 0.00090 + 0.00472 + 0.28671 = 0.29233 MMscf
Recoverable condensate = 9.72 + 84/42 = 11.72 stb = 40.1 stb per MMscf of produced gas.
Recoverable LPG = (277*0.0022 + 121*0.0023) = 0.888 tonne = 3.04 tonne/MMscf

## TABLE 4

## TYPICAL YOLLA WELL WELLHEAD PRESSURES

| RESERVOIR PRESSURE (psia) | WELLHEAD PRESSURE (psia) AT GAS PRODUCTION RATE | | | |
|---|---|---|---|---|
| | 3 MMscf/d | 6 MMscf/d | 10 MMscf/d | 14 MMscf/d |
| 4230 | 3014 | 2916 | 2736 | 2495 |
| 3500 | 2425 | 2319 | 2118 | 1833 |
| 3200 | 2192 | 2081 | 1864 | 1547 |
| 3000 | 2040 | 1924 | 1693 | 1344 |
| 2800 | 1890 | 1769 | 1519 | 1126 |
| 2600 | 1743 | 1613 | 1339 | 877 |
| 2400 | 1597 | 1456 | 1150 | 566 |
| 2200 | 1452 | 1296 | 944 | 0 |
| 2000 | 1306 | 1135 | 705 | N/A |
| 1900 | 1233 | 1049 | 564 | N/A |
| 1800 | 1162 | 960 | 395 | N/A |
| 1700 | 1087 | 869 | 134 | N/A |
| 1600 | 1011 | 773 | 0 | N/A |
| 1500 | 934 | 671 | N/A | N/A |
| 1400 | 855 | 559 | N/A | N/A |
| 1300 | 774 | 432 | N/A | N/A |
| 1200 | 690 | 286 | N/A | N/A |
| 1100 | 604 | 66 | N/A | N/A |
| 1000 | 512 | N/A | N/A | N/A |
| 900 | 414 | N/A | N/A | N/A |
| 800 | 312 | N/A | N/A | N/A |

The wellhead pressures were calculated using "FLOSYSTEM" software assuming the following:

1 Standard pseudosteady state calculation of flowing bottomhole pressure at a specified reservoir pressure and gas rate, using pressure.

2 Gray's vertical flow correlation.

3 Gas gravity of 0.78 and producing liquid to gas ratio of 40 bbls of 1.0 SG liquid per MMscf. Other fluid properties (viscosity, compressibility, density) calculated by "FLOSYSTEM" correlations.

4 Reservoir temperature 300°F, wellhead temperature 115°F and separator temperature 105°F.

5 Tubing with 2.992" internal diameter, down to perforations at 4101m MD at 45 degrees angle, corresponding to 2900m lateral displacement and 2900m TVD.

6 Wellbore radius 4.25". Drainage area 450 acres with radius 762m.

7 Reservoir permeability thickness product (kh) for each well of 7092 md-ft, corresponding to 308.4 md and 23 ft, and skin factor of +3 plus 0.1 per MMscf/d. The assumed kh, from AMOCO's interpretation of Yolla 1 DST 1, does not account for the reduction in effective permeability likely with retrograde condensate dropout. On the other hand, there is upside potential for increasing well productivity by commingling production from deeper zones.

## TABLE 5.1

FORECASTS OF GAS PRODUCTION AND WELLHEAD PRESSURE FOR THE 2900 m ZONE CASE 1

**For explanation of results, refer to notes at end of Table ~~4~~5.3.**

| Year | Raw Gas Production in Year (bcf) | Av. Daily Raw Gas in Year (MMscf/d) | Cum Gas Production (year end) (bcf) | Gas in Reservoir (year end) (bcf) | Reservoir Pressure (year end) (psia) | No. of production wells at year end | Typical peak well rate at year end (MMscf/d) | Typical WHP at year end (psia) |
|---|---|---|---|---|---|---|---|---|
| 1 | 32.47 | 89.0 | 32.5 | 567.5 | 4001.1 | 8 | 14 | 2290 |
| 2 | 32.47 | 89.0 | 64.9 | 535.1 | 3772.2 | 8 | 14 | 2083 |
| 3 | 32.47 | 89.0 | 97.4 | 502.6 | 3543.3 | 8 | 14 | 1873 |
| 4 | 32.47 | 89.0 | 129.9 | 470.1 | 3314.3 | 8 | 14 | 1658 |
| 5 | 32.47 | 89.0 | 162.4 | 437.7 | 3085.4 | 8 | 14 | 1432 |
| 6 | 32.47 | 89.0 | 194.8 | 405.2 | 2856.5 | 8 | 14 | 1190 |
| 7 | 32.47 | 89.0 | 227.3 | 372.7 | 2627.6 | 8 | 14 | 915 |
| 8 | 32.47 | 89.0 | 259.8 | 340.2 | 2398.7 | 14 | 8 | 1321 |
| 9 | 32.47 | 89.0 | 292.2 | 307.8 | 2169.8 | 14 | 8 | 1118 |
| 10 | 32.47 | 89.0 | 324.7 | 275.3 | 1940.9 | 14 | 8 | 898 |
| 11 | 28.57 | 78.3 | 353.3 | 246.7 | 1739.4 | 14 | then | then |
| 12 | 25.97 | 71.2 | 379.2 | 220.8 | 1556.3 | 14 | declining | declining |
| 13 | 23.38 | 64.0 | 402.6 | 197.4 | 1391.5 | 14 | .... | .... |
| 14 | 20.78 | 56.9 | 423.4 | 176.6 | 1245.0 | 14 | .... | .... |
| 15 | 18.18 | 49.8 | 441.6 | 158.4 | 1116.8 | 14 | .... | .... |
| 16 | 16.88 | 46.3 | 458.5 | 141.5 | 997.8 | 14 | .... | .... |
| 17 | 15.58 | 42.7 | 474.1 | 125.9 | 887.9 | 14 | 3 | 400 |

## TABLE 5.2

FORECASTS OF GAS PRODUCTION AND WELLHEAD PRESSURE FOR THE 2900 m ZONE CASE 2

| Year | Raw Gas Production in Year (bcf) | Av. Daily Raw Gas in Year (MMscf/d) | Cum Gas Production (year end) (bcf) | Gas in Reservoir (year end) (bcf) | Reservoir Pressure (year end) (psia) | No. of production wells at year end | Typical peak well rate at year end (MMscf/d) | Typical WHP at year end (psia) |
|---|---|---|---|---|---|---|---|---|
| 1 | 32.47 | 89.0 | 32.5 | 567.5 | 4001.1 | 8 | 14 | 2290 |
| 2 | 32.47 | 89.0 | 64.9 | 535.1 | 3772.2 | 8 | 14 | 2083 |
| 3 | 32.47 | 89.0 | 97.4 | 502.6 | 3543.3 | 8 | 14 | 1873 |
| 4 | 32.47 | 89.0 | 129.9 | 470.1 | 3314.3 | 8 | 14 | 1658 |
| 5 | 32.47 | 89.0 | 162.4 | 437.7 | 3085.4 | 8 | 14 | 1432 |
| 6 | 32.47 | 89.0 | 194.8 | 405.2 | 2856.5 | 8 | 14 | 1190 |
| 7 | 32.47 | 89.0 | 227.3 | 372.7 | 2627.6 | 8 | 14 | 915 |
| 8 | 32.47 | 89.0 | 259.8 | 340.2 | 2398.7 | 8 | 14 | ~~1321~~ 540 |
| 9 | 32.47 | 89.0 | 292.2 | 307.8 | 2169.8 | 14 | 8 | 1118 |
| 10 | 32.47 | 89.0 | 324.7 | 275.3 | 1940.9 | 14 | 8 | 898 |
| 11 | 31.17 | 85.4 | 355.9 | 244.1 | 1721.1 | 14 | 8 | 658 |
| 12 | 27.27 | 74.7 | 383.1 | 216.9 | 1528.9 | 14 | then | then |
| 13 | 24.81 | 68.0 | 407.9 | 192.1 | 1354.0 | 14 | declining | declining |
| 14 | 23.38 | 64.0 | 431.3 | 168.7 | 1189.2 | 14 | .... | .... |
| 15 | 20.78 | 56.9 | 452.1 | 147.9 | 1042.7 | 14 | .... | .... |
| 16 | 19.48 | 53.4 | 471.6 | 128.4 | 905.3 | 14 | .... | .... |
| 17 | 16.88 | 46.3 | 488.5 | 111.5 | 786.3 | 14 | 3 | 300 |

**TABLE 5.3**

FORECASTS OF GAS PRODUCTION AND WELLHEAD PRESSURE FOR THE 2900 m ZONE CASE 3

| Year | Raw Gas Production in Year (bcf) | Av. Daily Raw Gas in Year (MMscf/d) | Cum Gas Production (year end) (bcf) | Gas in Reservoir (year end) (bcf) | Reservoir Pressure (year end) (psia) | No. of production wells at year end | Typical peak well rate at year end (MMscf/d) | Typical WHP at year end (psia) |
|---|---|---|---|---|---|---|---|---|
| 1 | 32.47 | 89.0 | 32.5 | 567.5 | 4001.1 | 11 | 10 | 2541 |
| 2 | 32.47 | 89.0 | 64.9 | 535.1 | 3772.2 | 11 | 10 | 2348 |
| 3 | 32.47 | 89.0 | 97.4 | 502.6 | 3543.3 | 11 | 10 | 2155 |
| 4 | 32.47 | 89.0 | 129.9 | 470.1 | 3314.3 | 11 | 10 | 1961 |
| 5 | 32.47 | 89.0 | 162.4 | 437.7 | 3085.4 | 11 | 10 | 1766 |
| 6 | 32.47 | 89.0 | 194.8 | 405.2 | 2856.5 | 11 | 10 | 1568 |
| 7 | 32.47 | 89.0 | 227.3 | 372.7 | 2627.6 | 11 | 10 | 1364 |
| 8 | 32.47 | 89.0 | 259.8 | 340.2 | 2398.7 | 11 | 10 | 1148 |
| 9 | 32.47 | 89.0 | 292.2 | 307.8 | 2169.8 | 14 | 8 | 1118 |
| 10 | 32.47 | 89.0 | 324.7 | 275.3 | 1940.9 | 14 | 8 | 898 |
| 11 | 28.57 | 78.3 | 353.3 | 246.7 | 1739.4 | 14 | then | then |
| 12 | 25.97 | 71.2 | 379.2 | 220.8 | 1556.3 | 14 | declining | declining |
| 13 | 23.38 | 64.0 | 402.6 | 197.4 | 1391.5 | 14 | .... | .... |
| 14 | 20.78 | 56.9 | 423.4 | 176.6 | 1245.0 | 14 | .... | .... |
| 15 | 18.18 | 49.8 | 441.6 | 158.4 | 1116.8 | 14 | .... | .... |
| 16 | 16.88 | 46.3 | 458.5 | 141.5 | 997.8 | 14 | .... | .... |
| 17 | 15.58 | 42.7 | 474.1 | 125.9 | 887.9 | 14 | 3 | 400 |

**Notes:**

1) Raw gas bcf production in year = 1.2987 x ( number of PJ/yr forecast in Appendix 1)
2) Assume accessed OGIP = 600 bcf
3) Assume reservoir pressure = 4230 psia x ratio of gas in reservoir to OGIP. This calculation assumes ideal gas behaviour (a reasonable simplification at this pre-appraisal stage) and also assumes that water influx will be negligible as expected.
4) Number of wells at year end comes from Appendix 3.
5) Typical peak well rate is an approximate number. In the first 10 years, with a 25 PJ/yr contract, it is assumed that the field deliverability must be at least 100 MMscf/d with one well shut-in. Then at the end of Year 17 the assumed final rate is 3 MMscf/d per well.
6) The WHP is calculated using FLOSYSTEM software for the specified reservoir pressure and production rate, based on the assumptions listed in Table 4.

**For definition of cases, refer to Appendix 1**

**TABLE 6 (two pages)**

**COST ESTIMATES FOR DEVELOPING THE GAS IN THE 2900 m ZONE**

**OVERALL SUMMARY OF COSTS DETAILED IN APPENDIX 1 (MM 1995 Aus $)**

**Note:** As the author's expertise is primarily in petroleum engineering, the upstream capital and operating cost estimates are reasonable for this pre-appraisal stage (perhaps +/-30%) whereas the downstream costs are unreliable. The downstream costs were obtained mainly from very broad brush estimates made in 1994 with the assistance of Brown and Root. These estimates were based on general correlations with facilities costs in other fields, without a detailed consideration of Yolla processes.

CASE 1

| Year | U/S Cap | P/L Cap | Facs Cap | Total Cap | U/S Op | D/S Op | Abandonment |
|---|---|---|---|---|---|---|---|
| 0 | 76 | 141 | 120 | 337 | 0 | 0 | 0 |
| 1 | 0 | 0 | 0 | 0 | 3 | 21 | 0 |
| 2 | 0 | 0 | 0 | 0 | 3 | 21 | 0 |
| 3 | 0 | 0 | 0 | 0 | 3 | 21 | 0 |
| 4 | 0 | 0 | 0 | 0 | 3 | 21 | 0 |
| 5 | 0 | 0 | 0 | 0 | 3 | 21 | 0 |
| 6 | 0 | 0 | 0 | 0 | 3 | 21 | 0 |
| 7 | 0 | 0 | 0 | 0 | 3 | 21 | 0 |
| 8 | 60 | 0 | 0 | 60 | 8 | 21 | 0 |
| 9 | 0 | 0 | 0 | 0 | 4 | 21 | 0 |
| 10 | 0 | 0 | 0 | 0 | 4 | 21 | 0 |
| 11 | 0 | 0 | 0 | 0 | 4 | 21 | 0 |
| 12 | 0 | 0 | 0 | 0 | 4 | 21 | 0 |
| 13 | 0 | 0 | 0 | 0 | 4 | 21 | 0 |
| 14 | 0 | 0 | 0 | 0 | 4 | 21 | 0 |
| 15 | 0 | 0 | 0 | 0 | 4 | 21 | 0 |
| 16 | 0 | 0 | 0 | 0 | 4 | 21 | 0 |
| 17 | 0 | 0 | 0 | 0 | 4 | 21 | 0 |
| 18 | 0 | 0 | 0 | 0 | 0 | 0 | 79.4 |
| **TOTAL** | **136** | **141** | **120** | **397** | **65** | **357** | **79.4** |

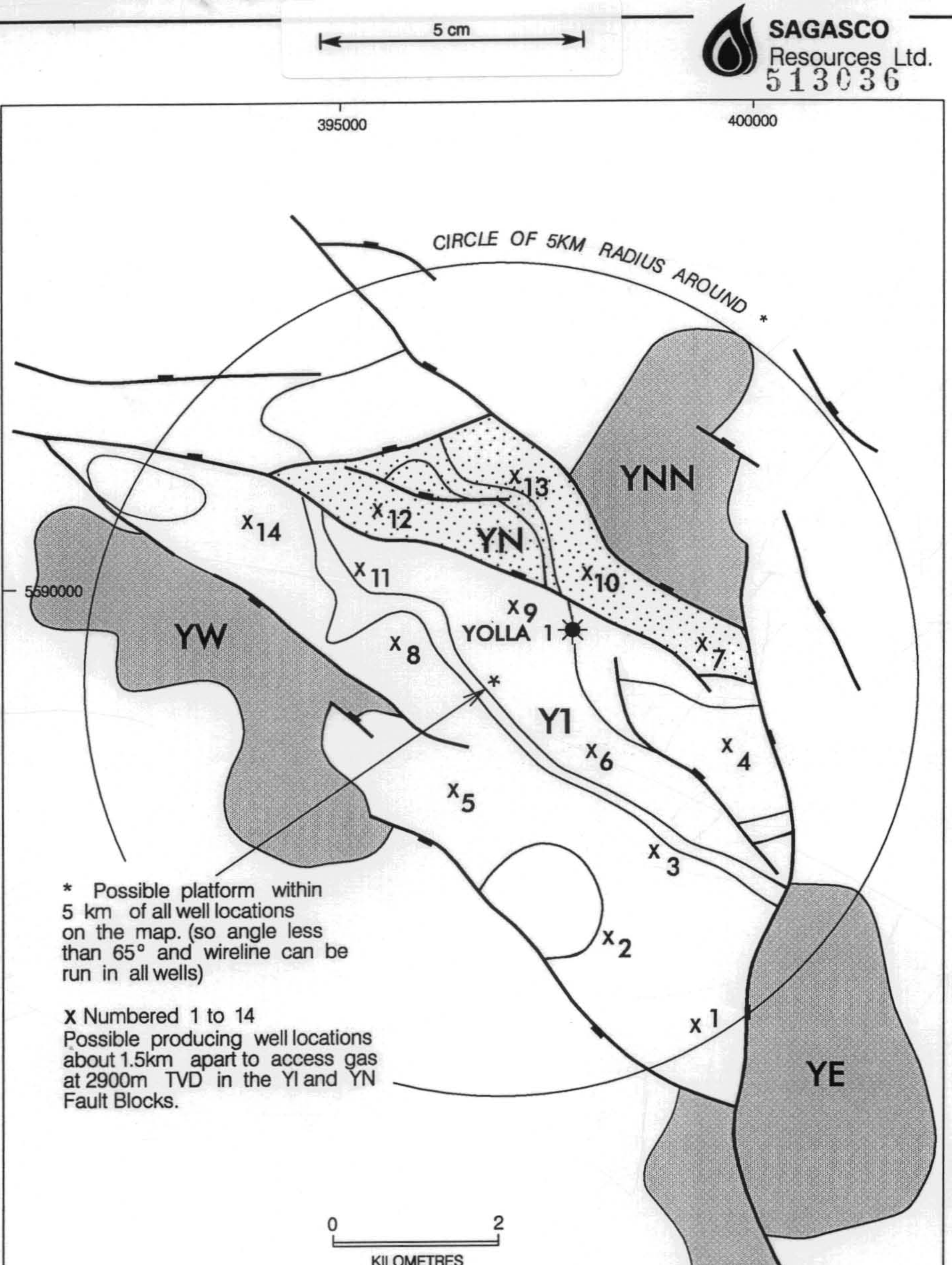
**TABLE 6 (Page two of two)**

CASE 2

| Year | U/S Cap | P/L Cap | Facs Cap | Total Cap | U/S Op | D/S Op | Abandonment |
|---|---|---|---|---|---|---|---|
| 0 | 76 | 85 | 163 | 324 | 0 | 0 | 0 |
| 1 | 0 | 0 | 0 | 0 | 3 | 32 | 0 |
| 2 | 0 | 0 | 0 | 0 | 3 | 32 | 0 |
| 3 | 0 | 0 | 0 | 0 | 3 | 32 | 0 |
| 4 | 0 | 0 | 0 | 0 | 3 | 32 | 0 |
| 5 | 0 | 0 | 0 | 0 | 3 | 32 | 0 |
| 6 | 0 | 0 | 0 | 0 | 3 | 32 | 0 |
| 7 | 0 | 0 | 0 | 0 | 3 | 32 | 0 |
| 8 | 0 | 0 | 0 | 0 | 3 | 32 | 0 |
| 9 | 60 | 0 | 0 | 60 | 8 | 32 | 0 |
| 10 | 0 | 0 | 0 | 0 | 4 | 32 | 0 |
| 11 | 0 | 0 | 0 | 0 | 4 | 32 | 0 |
| 12 | 0 | 0 | 0 | 0 | 4 | 32 | 0 |
| 13 | 0 | 0 | 0 | 0 | 4 | 32 | 0 |
| 14 | 0 | 0 | 0 | 0 | 4 | 32 | 0 |
| 15 | 0 | 0 | 0 | 0 | 4 | 32 | 0 |
| 16 | 0 | 0 | 0 | 0 | 4 | 32 | 0 |
| 17 | 0 | 0 | 0 | 0 | 4 | 32 | 0 |
| 18 | 0 | 0 | 0 | 0 | 0 | 0 | 76.8 |
| **TOTAL** | **136** | **85** | **163** | **384** | **64** | **544** | **76.8** |

CASE 3

| Year | U/S Cap | P/L Cap | Facs Cap | Total Cap | U/S Op | D/S Op | Abandonment |
|---|---|---|---|---|---|---|---|
| 0 | 103 | 141 | 98 | 342 | 0 | 0 | 0 |
| 1 | 0 | 0 | 0 | 0 | 3.5 | 21 | 0 |
| 2 | 0 | 0 | 0 | 0 | 3.5 | 21 | 0 |
| 3 | 0 | 0 | 0 | 0 | 3.5 | 21 | 0 |
| 4 | 0 | 0 | 0 | 0 | 3.5 | 21 | 0 |
| 5 | 0 | 0 | 0 | 0 | 3.5 | 21 | 0 |
| 6 | 0 | 0 | 0 | 0 | 3.5 | 21 | 0 |
| 7 | 0 | 0 | 22 | 22 | 3.5 | 21 | 0 |
| 8 | 0 | 0 | 0 | 0 | 3.5 | 21 | 0 |
| 9 | 33 | 0 | 0 | 33 | 10 | 21 | 0 |
| 10 | 0 | 0 | 0 | 0 | 4 | 21 | 0 |
| 11 | 0 | 0 | 0 | 0 | 4 | 21 | 0 |
| 12 | 0 | 0 | 0 | 0 | 4 | 21 | 0 |
| 13 | 0 | 0 | 0 | 0 | 4 | 21 | 0 |
| 14 | 0 | 0 | 0 | 0 | 4 | 21 | 0 |
| 15 | 0 | 0 | 0 | 0 | 4 | 21 | 0 |
| 16 | 0 | 0 | 0 | 0 | 4 | 21 | 0 |
| 17 | 0 | 0 | 0 | 0 | 4 | 21 | 0 |
| 18 | 0 | 0 | 0 | 0 | 0 | 0 | 79.4 |
| **TOTAL** | **136** | **141** | **120** | **397** | **70** | **357** | **79.4** |




# GAS WELL LOCATIONS IN YOLLA FIELD FAULT COMPARTMENTS

FIGURE 1

12794.0295

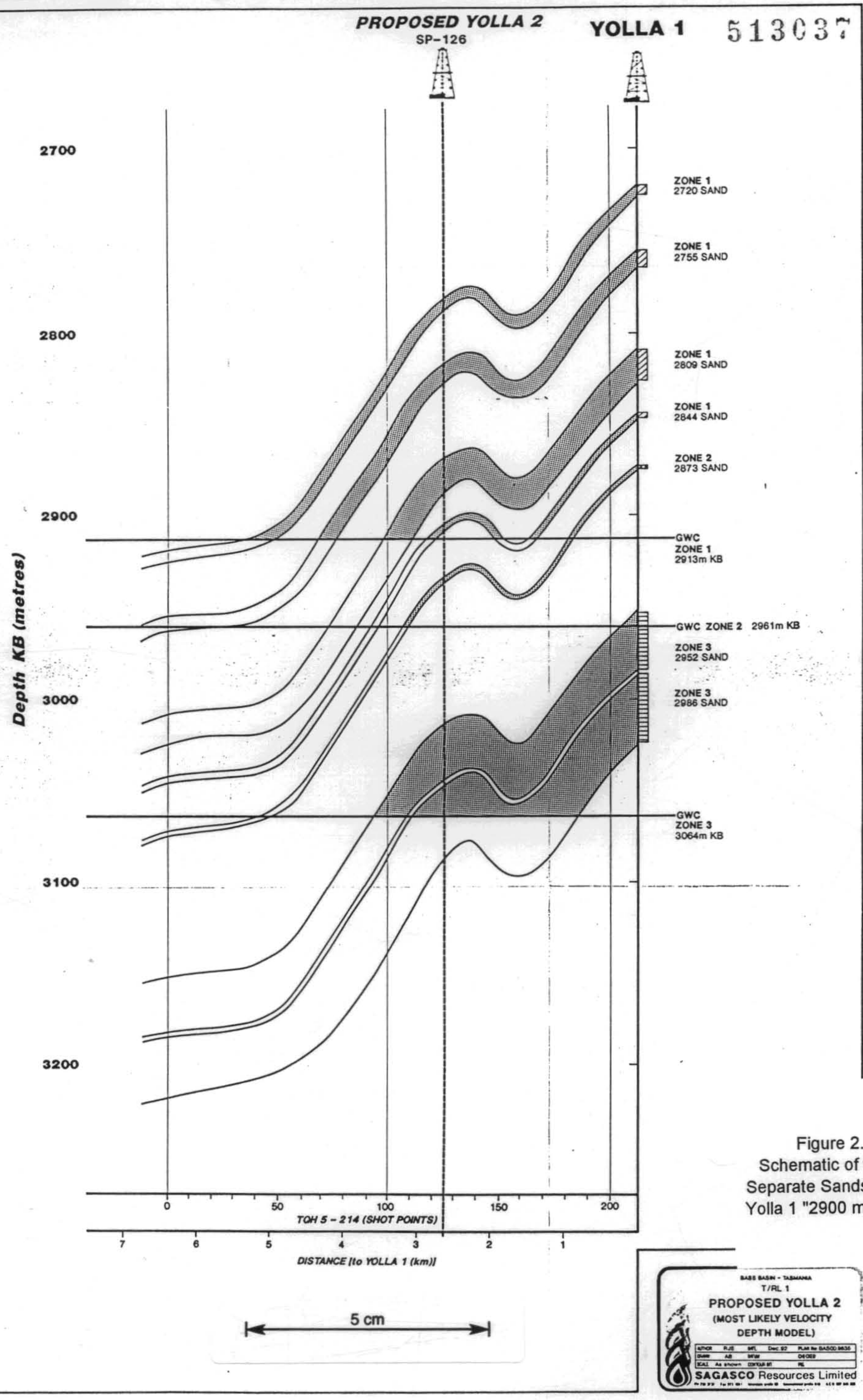



Figure 2.
Schematic of the 7
Separate Sands in the
Yolla 1 "2900 m Zone"

518038

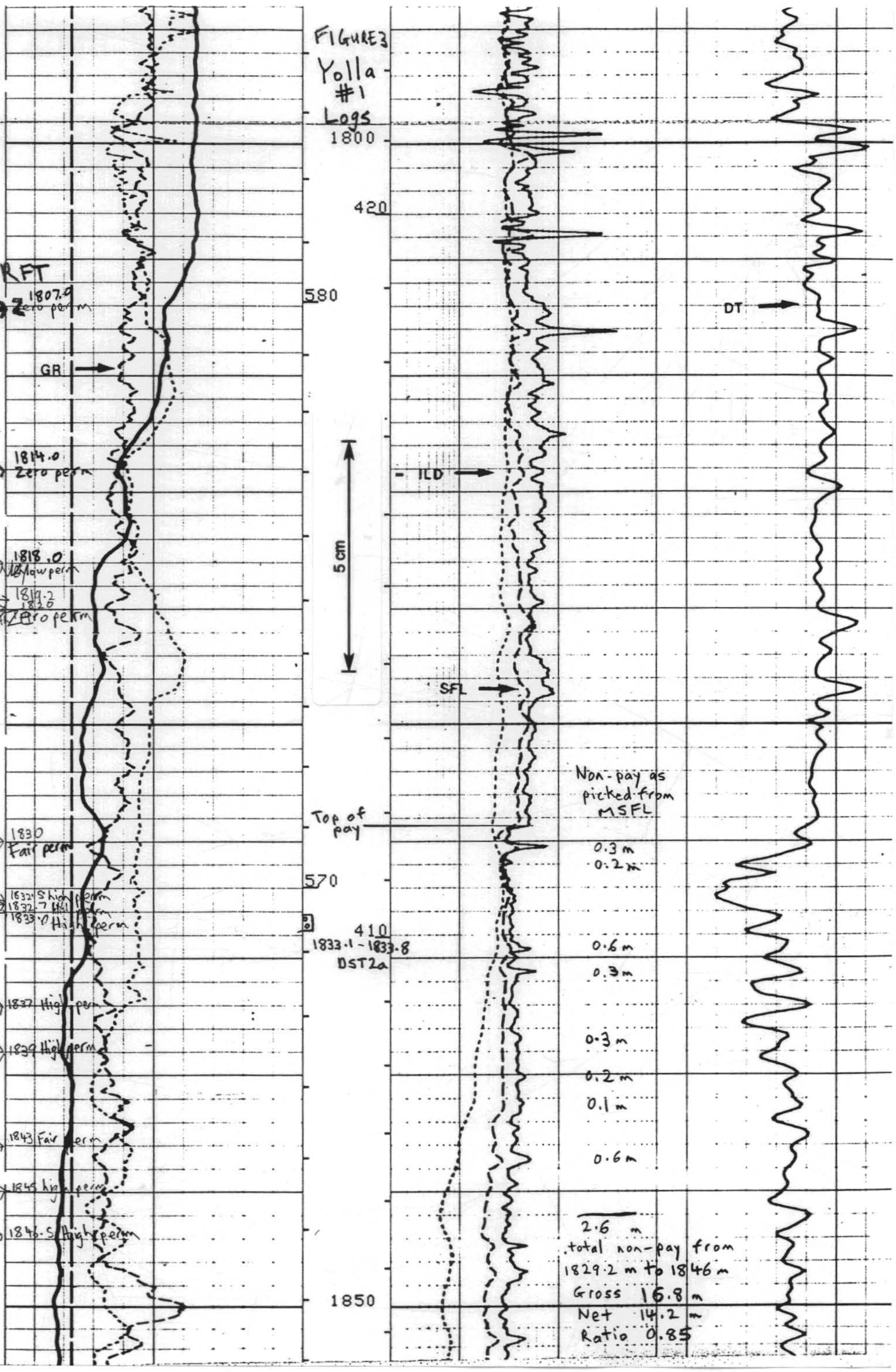
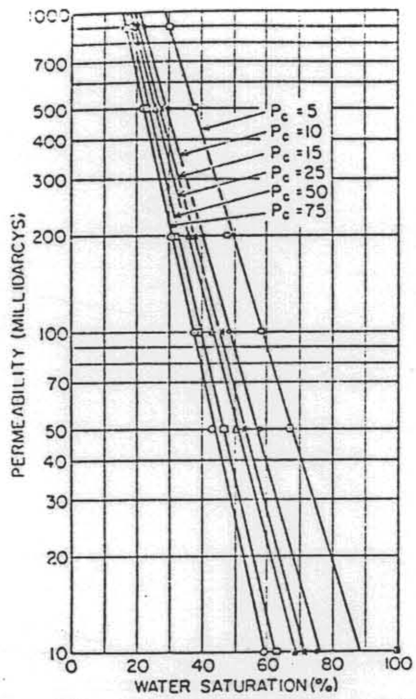


FIGURE 3
Yolla #1
Logs
1800
420
580
RFT
1807.9 Zero perm
GR
1814.0 Zero perm
1818.0 low perm
1819.2
1820
Both Zero perm
DT
ILD
5 cm
SFL
Non-pay as picked from MSFL
Top of pay
1830 Fair perm
0.3 m
0.2 m
570
1832.5 high perm
1832.7 High perm
1833.0 High perm
410
1833.1 - 1833.8
DST2a
0.6 m
0.3 m
1837 High perm
1839 High perm
0.3 m
0.2 m
0.1 m
1843 Fair perm
0.6 m
1845 high perm
1846.5 High perm
2.6 m
total non-pay from 1829.2 m to 1846 m
Gross 16.8 m
Net 14.2 m
Ratio 0.85
1850

**FIGURE 4 LITERATURE CAPILLARY PRESSURE DATA**

5 cm




Assumed to be laboratory data with air-brine interfacial tension of 72 dynes/cm, about 2.5 times in situ IFT.

Figure . Correlation of water saturation with permeability for various capillary pressures (from data of Wright & Wooddy ).

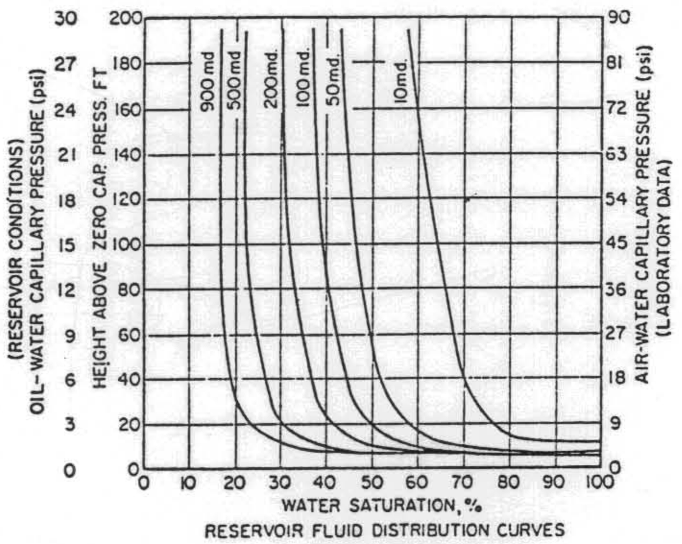



Figure . Series of capillary-pressure curves as a function of permeability (from Wright and Wooddy ).

Reference: H.T. Wright, Jr and L.D. Wooddy, Jr, "Formation Evaluation of the Borregas and Seeligson Fields, Brooks and Jim Wells Counties, Texas," Symposium of Formation Evaluation, AIME, Oct 1955, p 135.

# APPENDIX 1

4-PAGE PRINTOUT OF SPREADSHEET DETAILING GAS DEVELOPMENT OF THE 2900 m ZONE

Case 1 - 3-phase pipeline to separation/compression facilities onshore. Minimal facilities on the platform. Compression from time of field startup.

Case 2 - Separation/compression facilities on platform except onshore CO2 & last stage separation. One 2-phase pipeline (hydrocarbon liquid injected into high P gas). Compression from time of field startup.

Case 3 - As Case 1 (onshore compression) except compression deferred until 11-well rate is too low.

**Pipeline pressure drop, diameters and minimum WHP.**

Data : From 1994 Brown & Root Study, assume 230 psi pressure drop at 70 MMscf/d with 16" line
Also assume pressure drop proportional to diameter to power -5 and rate to power 2.

Case 1& 3 pressure drop to shore at 42 MMscf/d (14 wells*3) = 230*(42/70)^2 = 83 psi. Assume 100 psi drop from WHP and 300 psia needed into facilities, so minimum WHP = 400 psia.

In Case 2 a 12" gas line is OK according to Brown/Root, with platform pressure at 100 MMscf/d:
P = 1000 + 230 * (100/70)^2 * (16/12)^5 = 2953.395 psia if 1000 psia at shore. A compressor on the platform will be able to get discharge pressure to 2953 psia OK.
Assume 300 psia minimum WHP.
**Cannot run without compression with 12" line because require WHP>2953 psia (impossible).**

**Case 1 and Case 3 Recoverable Gas Reserves**

At 3 MMscf/d per well (42 MMscf/d for 14-well field), WHP drops below 400 psia at 887 psia reservoir P.
Final reservoir pressure = 887 psia, when z is about the same as at initial pressure 4230 psia.
Recovery factor = (4230-887)/4230 = 79.0%
OGIP = 600 bcf, so recoverable reserves = 474 bcf

**Case 1 and Case 3 Forecast**
Assume 0.77 PJ sales gas per bcf of raw gas recovered from the wells (as in "Yolla Reserves" Report by Richard Suttill dated Feb 1993). Based on 0.7 "sales factor" (accounting for CO2, fuel, membrane losses) and 1.1 MJ/scf heating value.
Assume 25 PJ/yr market until recover 70% of reserves, then declining rate to final 42 MMscf/d
Assume 63 stb of hydrocarbon liquids per MMscf of raw gas recovered from the wells

Calculations: Recoverable reserves = 474 bcf = 365.0 PJ sales
25 PJ/yr is equivalent to raw gas of 32.47 bcf/yr = average 89.0 MMscf/d
Final rate of 42 MMscf/d (3 MM * 14 wells) = 15.33 bcf/yr = 11.8 PJ sales per yr
70% of recoverable reserves = 255.5 PJ, so get 10 years at 25 PJ sales per yr
Remaining years recover 115 PJ sales gas as follows:

| | | | | ROUNDED | |
|---|---|---|---|---|---|
| Year | PJ/yr | bcf/yr | MMstb/yr | PJ/yr | MMstb/yr |
| 1 to 10 | 25 | 32.46753 | 2.045455 | 25 | 2.04 |
| 11 | 22.5 | 29.22078 | 1.840909 | 22 | 1.8 |
| 12 | 20.25 | 26.2987 | 1.656818 | 20 | 1.6 |
| 13 | 18.225 | 23.66883 | 1.491136 | 18 | 1.5 |
| 14 | 16.4025 | 21.30195 | 1.342023 | 16 | 1.3 |
| 15 | 14.76225 | 19.17175 | 1.20782 | 14 | 1.2 |
| 16 | 13.28603 | 17.25458 | 1.087038 | 13 | 1.1 |
| 17 | 11.95742 | 15.52912 | 0.978335 | 12 | 1 |
| TOTAL | 367.3832 | 477.121 | | 365 | 29.9 |

**Case 2 Recoverable Gas Reserves**
At 3 MMscf/d per well (42 MMscf/d for 14-well field), WHP drops below 300 psia at 788 psia reservoir P.
Final reservoir pressure = 788 psia, when z is about the same as at initial pressure 4230 psia.
Recovery factor = (4230-788)/4230 = 81.4%
OGIP = 600 bcf, so recoverable reserves = 488.4 bcf

**Case 2 Forecast**
Assume 0.77 PJ sales gas per bcf of raw gas recovered from the wells.
Assume 25 PJ/yr market until recover 70% of reserves, then declining rate to final 42 MMscf/d
Assume 63 stb of hydrocarbon liquids per MMscf of raw gas recovered from the wells

Calculations:

Recoverable reserves = 488.4 bcf = 376.1 PJ sales
25 PJ/yr is equivalent to raw gas of 32.47 bcf/yr = average 89.0 MMscf/d
Final rate of 42 MMscf/d (3 MM * 14 wells) = 15.33 bcf/yr = 11.8 PJ sales per yr
70% of recoverable reserves = 263.2 PJ, so get 10 years at 25 PJ sales per yr
Remaining years recover 126.1 PJ sales gas as follows:

| | | | | ROUNDED | |
|---|---|---|---|---|---|
| Year | PJ/yr | bcf/yr | MMstb/yr | PJ/yr | MMstb/yr |
| 1 to 10 | 25 | 32.46753 | 2.045455 | 25 | 2.04 |
| 11 | 22.875 | 29.70779 | 1.871591 | 24 | 1.9 |
| 12 | 20.93063 | 27.18263 | 1.712506 | 21 | 1.8 |
| 13 | 19.15152 | 24.87211 | 1.566943 | 19.1 | 1.6 |
| 14 | 17.52364 | 22.75798 | 1.433753 | 18 | 1.5 |
| 15 | 16.03413 | 20.82355 | 1.311884 | 16 | 1.3 |
| 16 | 14.67123 | 19.05355 | 1.200373 | 15 | 1.2 |
| 17 | 13.42418 | 17.434 | 1.098342 | 13 | 1.1 |
| TOTAL | 374.6103 | 486.5069 | | 376.1 | 30.8 |

**Timing of Compression and Well Drilling**

Criterion: Need 100 MMscf/d field capacity with one well off line, in at least Years 1 to 10.

Case 1: Assume drill 8 wells initially and have compression on immediately.
Pressure drop to shore at 100 MMscf/d = 230*(100/70)^2 = 469 psi (pipe assumptions above)
Assuming that need 300 psi onshore, WHP = 769 psi.

To get 100 MMscf/d when 8 development wells, need 14 MMscf/d per well. At this rate the WHP drops below 769 psi when reservoir pressure = 2500 psia and raw gas recovery = 600 bcf*(4230-2500)/4230 = 245.4 bcf. This corresponds to 7.6 years production at 32.47 bcf per year, so the last 6 wells would need to be drilled in Year 8.

Case 2: Assume drill 8 wells initially and have compression on immediately.
Assume that require minimum WHP = 300 psi.

To get 100 MMscf/d when 8 development wells, need 14 MMscf/d per well. At this rate the WHP drops below 300 psi when reservoir pressure = 2300 psia and raw gas recovery = 600 bcf*(4230-2300)/4230 = 273.8 bcf. This corresponds to 8.4 years production at 32.47 bcf per year, so the last 6 wells would need to be drilled in Year 9.

Case 3: Assume drill 11 wells initially and have no compression.
Pressure drop to shore at 100 MMscf/d = 230*(100/70)^2 = 469 psi (pipe assumptions above)
Assuming that need 1000 psi onshore, WHP = 1469 psi.

To get 100 MMscf/d when 11 development wells, need 10 MMscf/d per well. At this rate the WHP drops below 1469 psi when reservoir pressure = 2750 psia and raw gas recovery = 600 bcf*(4230-2750)/4230 = 209.9 bcf. This corresponds to 6.5 years production at 32.47 bcf per year, so compression would be needed in Year 7.
After compression is put on, required WHP is 769 psi as in Case 1. With wells at 10 MMscf/d this WHP is reached when reservoir pressure = 2250 psia and raw gas recovery = 600 bcf*(4230-2250)/4230 = 281 bcf. This corresponds to 8.6 years production at 32.47 bcf per year, so the last 3 wells would need to be drilled in Year 9.

**Upstream Capital and Operating Development Costs 1995 Aus $ (Wells)**

**EXCLUDING EXPLORATION COSTS**
**ASSUME THAT PREVIOUSLY DRILLED 3 APPRAISAL WELLS (YOLLA 2, 3 AND 4)**

| | | |
|---|---|---|
| CASE 1 OUTLINE | Year 0 - (capital) | $76 MM to drill/complete 8 deviated gas development wells to 3000 m. ($4 MM mob/demob plus $9 MM per well) |
| | Year 1 | Opcosts assume $3 MM/year for wireline/testing/reservoir management and unscheduled workovers or coiled tubing. No capital expenditure. |
| | Yrs 2 to 7 | Same as Year 1 |
| | Year 8 | As Yr 1 plus $5 MM rig opcost plus $60 MM capital to drill/complete 6 wells and re-complete some others (total Upstream $60 MM capital + $8 MM opcost) |
| | Yrs 9 to 17 | Opcosts assume $4 MM/year for same items as in Year 1; no capital |

| | | |
|---|---|---|
| CASE 2 OUTLINE | Year 0 - (capital) | $76 MM to drill/complete 8 deviated gas development wells to 3000 m. |
| | Year 1 | Opcosts assume $3 MM/year for wireline/testing/reservoir management and unscheduled workovers or coiled tubing. No capital expenditure. |
| | Yrs 2 to 8 | Same as Year 1 |
| | Year 9 | As Yr 1 plus $5 MM rig opcost plus $60 MM capital to drill/complete 6 wells and re-complete some others (total Upstream $60 MM capital + $8 MM opcost) |
| | Yrs 10-17 | Opcosts assume $4 MM/year for same items as in Year 1; no capital |

| | | |
|---|---|---|
| CASE 3 OUTLINE | Year 0 - (capital) | $103 MM to drill/complete 11 deviated gas development wells to 3000 m. |
| | Year 1 | Opcosts assume $3.5 MM/year for wireline/testing/reservoir management and unscheduled workovers or coiled tubing. No capital expenditure. |
| | Yrs 2 to 8 | Same as Year 1 |
| | Year 9 | As Yr 1 plus $6.5 MM rig opcost plus $33 MM capital to drill/complete 3 wells and re-complete some others (total Upstream $33 MM capital + $10 MM opcost) |
| | Yrs 10-17 | Opcosts assume $4 MM/year for same items as in Year 1; no capital |

**Pipeline capital costs 1995 Aus $, all incurred in Year 0**

CASE 1 (& Case 3) One 200 km pipeline with 16" diameter cost $140 MM (1994 estimate by Brown & Root was 100.74 MM US $) plus $1 MM liquid sales line to the refinery. TOTAL $141 MM.

CASE 2 One 200 km pipeline with 12" diameter cost $84 MM (1994 estimate by Brown & Root was 60.24 MM US $) plus $1 MM liquid sales line to the refinery. TOTAL $85 MM.

**Onshore Facility Costs 1995 Aus $**

CASE 1 $50 MM (Based on $43 MM assumed for Sophia Jane 20 PJ/yr analysis in Oct 1994) all incurred in Year 0. Case 1 includes major compression onshore.

CASE 2 $25 MM all incurred in Year 0. (Assume $25 MM reduction from Case 1 because no compression or water handling/disposal in the onshore plant).

CASE 3 $28 MM incurred in Year 0 plus $22 MM in Year 7 (when install major compression). Extra initial costs compared to Case 2 are for water handling and disposal).

**Offshore Facility Costs 1995 Aus $, all incurred in Year 0**

Costs based on Brown/Root cost of 44.317 MM 1994 USD for 12-well platform+facs without comp.
and 87.659 1994 USD for 12-well platform+facilities with compression.
(divide by 0.7 to convert currency to 1995 Aus $ and multiply by 1.1 to correct for 14 wells rather than 12)
CASE 1 & CASE 3: $70 MM

CASE 2 $138 MM

**Downstream Operating Costs**

Costs based on Brown/Root yearly opcost of 14.65 MM 1994 USD for 12-well platform+facs without compression and 22.53 1994 USD for 12-well platform+facilities with compression.
(divide by 0.7 to convert currency to 1995 Aus $ and assume that the 12-well platform estimate applies)

CASE 1 & CASE 3: $21 MM 1995 AUD/yr

CASE 2 $32 MM 1995 AUD/yr

**ABANDONMENT COSTS**

Assume 20% of total capital spent throughout the project. Assume costs incurred in Year 18.

**APPENDIX 2 - THREE-PAGE PRINTOUT OF CASE 2a SPREADSHEET**

**Definition of Case 2a**

Gas & oil wells with produced water; separation/compression/water disposal facilities on platform except onshore CO2/last separation; two separate pipelines to shore (gas & liquid). Assume gas development same as Case 2. Development of oil at 3000 m depth is incremental in terms of costs and liquid production. Assume no incremental gas production after incremental fuel use.

**Note: Implicitly assuming (as in Case 2) that onshore facility is near the Geelong Refinery, so minimal oil transport costs, and have compressor offshore for gaslift & gas injection.**

**Case 2a pipeline pressure drop, diameters and WHP.**

In Case 2a , assume a 6" liquid line to shore. A 12" gas line is assumed, as for Case 2.

Check 6" line liquid velocity if 15,000 bopd plus 100 MMscf/d*50 bbl of condensate per MMscf:

v = (15000 + 100*50)*0.159 m3/d / ( 0.016 m2 area) /(24*3600 s/day) = 2.3 m/sec (reasonable).

For gaslifted wells producing oil+water, assume need gaslift valve at 2000 m TVD where wellbore pressure is 2300 psi (300 psi WHP plus 1 psi/m*2000 m), and assume that 2500 psia surface pressure is required in the gaslift line. Using these assumptions, along with the result listed in Table 1 that the highest WHP with 8 wells initially in the gas development is 2495 psia (for a well at 14 MMscf/d when reservoir P = 4230 psia, the original pressure), it is concluded that the natural pressure from the gas producers is NOT sufficient for gaslift. The gaslift gas must be compressed, along with gas injected into the reservoir that probably requires an even higher surface pressure.

**Case 2a Oil Production assuming 13.5 MMstb reserves**
**(25% of 54 MMstb OOIP in a 10 square km area with a 15 metre oil column),**
**Start 15,000 bopd, 10% downtime and end 605 bopd (9 years @ 30% annual decline).**

OOIP calculation assuming 0.14 porosity and 0.7 oil saturation and 1.7 rb/stb formation factor, slightly higher than the 1.617 rb/stb at 1800 m because of more dissolved gas in the deeper zone.

OOIP = 0.14*0.7*15m*10 million sq m*6.2898 bbl/m3/(1.7 bbl/stb) = 54 MMstb

| Yearly decline | Rate at start of year | Rate at end of year | Av oil rate in yr | Yearly Mstb | Cum Mstb | Year | Rounded MMstb oil per year |
|---|---|---|---|---|---|---|---|
| 30% | 15,000 | 10500 | 11475 | 4188.375 | 4188.375 | 1 | 4.2 |
| 70% | 10500 | 7350 | 8032.5 | 2931.863 | 7120.238 | 2 | 2.9 |
| | 7350 | 5145 | 5622.75 | 2052.304 | 9172.541 | 3 | 2.1 |
| | 5145 | 3601.5 | 3935.925 | 1436.613 | 10609.15 | 4 | 1.4 |
| | 3601.5 | 2521.05 | 2755.148 | 1005.629 | 11614.78 | 5 | 1 |
| | 2521.05 | 1764.735 | 1928.603 | 703.9402 | 12318.72 | 6 | 0.7 |
| | 1764.735 | 1235.3145 | 1350.022 | 492.7581 | 12811.48 | 7 | 0.5 |
| | 1235.3145 | 864.72015 | 945.0156 | 344.9307 | 13156.41 | 8 | 0.4 |
| | 864.72015 | 605.30411 | 661.5109 | 241.4515 | 13397.86 | 9 | 0.3 |
| | | | | | | | 13.5 |

**Case 2a Well Number and Productivity (incremental wells for 3000 m oil development)**

Assume 300 m (1000') effective horizontal section, so half well length L = 500 feet

Assume 300 md kh, 30md Kv and 0.27 cp oil viscosity

Assume constant P boundary above and below well, in centre of 50 ft (15 m) oil column

Assume 3000 bopd per well, with 5 producing wells. Each well recovers 25% of OOIP in a 1kmx2km area, which works out to 2.7 MMstb per well. Assume 2 wells for gas re-injection.

Calculate pressure drop per well using Kuchuk and Goode and Tham et al Correlation

| | | | | | |
|---|---|---|---|---|---|
| Zw ft | 25 | | cot(piZw/2h) | 0.999796 | |
| h ft | 50 | | (Kv/Kh)^0.5 | 0.316228 | |
| K hori md | 300 | | log of a lot of stuff | 2.605232 | |
| k vert md | 30 | | 0.4343*a lot | 2.102831 | |
| u cp | 0.27 | | 162.6*a lot | 22.22314 | |
| Sm | 5 | | Pressure drop | 22.22314 | psi |
| rw ft | 0.24 | | | | |
| q rb/day | 5100 | (3000 stb per day) | | | |

Expected pressure drop of 22 psi is OK for minimising gas coning, so 3000 bopd is a reasonable initial rate.

**Upstream Capital and Operating Development Costs 1995 Aus $ (Wells)**

CASE 2a incremental compared to Case 2 **(EXCLUDING EXPLORATION COSTS)**

| | | |
|---|---|---|
| OUTLINE | Year 0 - (capital) | $77 MM to drill/complete 5 horizontal wells plus 2 gas injection wells at 3000 m TVD ($12 MM per horizontal well + $8.5 MM per gas injection well) |
| | Yrs 1 to 9 | Opcosts assume $1.5 MM/year for wireline/test/CT/gaslift/reservoir management. |
| | **Year 9 Capex saving:** | In Case 2 (no oil development) spend $60 MM on recompletions & 6 new wells. Assume that 4 of the new wells (each $9 MM) are replaced by $2 MM recompletions from oil producers/gasinjectors, so save $28 MM in Case 2a. |

**Incremental pipeline capital costs 1995 Aus $, all incurred in Year 0**

Case 2a (bigger onshore liquid line to the refinery and 2 offshore lines - one 12" other 6") versus Case 2 (minor onshore line + one 12" line offshore at $85 MM): assume $30 MM incremental.

**Incremental Onshore Facility Costs 1995 Aus $, all incurred in Year 0**

In Case 2a assume $3 MM incremental versus Case 2 ($30 MM cost) to account for extra liquids handling.

**Case 2a Compared to Case 2 - Offshore Facility Costs 1995 Aus $, all incurred in Year 0**

Extra costs for water disposal, higher production rates, more compression because of gaslift and injection, 15 well slots instead of 14 and the need to handle widely varying WHPs. Assume incremental 15% (equal to $21 MM) versus Case 2, in which the offshore facility cost is $138 MM.

**Case 2a Compared to Case 2 - Downstream Operating Costs**

Minor extra costs for water disposal, higher production rates, more compression because of gaslift and injection, and an extra 5 producing wells. Assume incremental $0.5 MM per year versus Case 2.

**Abandonment Costs (Case 2a incremental versus Case 2)**

Assume 20% of total incremental capital spent throughout the project.
Assume that this cost is incurred in Year 18, along with the abandonment of the gas development (Case 2).

**SUMMARY OF INCREMENTAL COSTS FOR CASE 2a VERSUS CASE 2**

| Year | U/S Cap | P/L Cap | Facs Cap | Total Cap | U/S Op | D/S Op | Abandonment |
|---|---|---|---|---|---|---|---|
| 0 | 77 | 30 | 21+ 3 =24 | 131 | 0 | 0 | 0 |
| 1 to 8 | 0 | 0 | 0 | 0 | 1.5 | 0.5 | 0 |
| 9 | -28 | 0 | 0 | -28 | 1.5 | 0.5 | 0 |
| 10 to 17 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 18 | 0 | 0 | 0 | 0 | 0 | 0 | 20.6 |
| **TOTAL** | **49** | **30** | **24** | **103** | **13.5** | **4.5** | **20.6** |

**SIMPLE APPROXIMATION OF INCREMENTAL ECONOMICS FOR CASE 2a VERSUS CASE 2**

Assume:
1. All calculations in millions of 1995 Aus dollars, unescalated, then NPV to Year 0 calculated at 10% rate.
2. Royalty paid at 10% of wellhead value. Ignore past deprecation credits.
3. Corporated Income Tax Rate = 0.33. Ignore past depreciation credits ("Project-based" economics).
4. Oil price $25/stb
5. Neglect any time delays of cash flows.
6. Simple straight 10% per year depreciation.
7. Assume that no incremental exploration expenditure in Case 2a versus Case 2.

| Year | Upstream Capital | Facilities Capital | Pipeline Capital | Total Capital | Upstream Opcost | D/stream Opcost | Oil MMStb | Oil revenue |
|---|---|---|---|---|---|---|---|---|
| 0 | -77 | -24 | -30 | -131 | 0 | 0 | 0 | 0 |
| 1 | 0 | 0 | 0 | 0 | -1.5 | -0.5 | 4.2 | 105 |
| 2 | 0 | 0 | 0 | 0 | -1.5 | -0.5 | 2.9 | 72.5 |
| 3 | 0 | 0 | 0 | 0 | -1.5 | -0.5 | 2.1 | 52.5 |
| 4 | 0 | 0 | 0 | 0 | -1.5 | -0.5 | 1.4 | 35 |
| 5 | 0 | 0 | 0 | 0 | -1.5 | -0.5 | 1 | 25 |
| 6 | 0 | 0 | 0 | 0 | -1.5 | -0.5 | 0.7 | 17.5 |
| 7 | 0 | 0 | 0 | 0 | -1.5 | -0.5 | 0.5 | 12.5 |
| 8 | 0 | 0 | 0 | 0 | -1.5 | -0.5 | 0.4 | 10 |
| 9 | 28 | 0 | 0 | Save 28 | -1.5 | -0.5 | 0.3 | 7.5 |
| 10 to 17 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 18 | **In Year 18, $20.6 million incremental expenditure on abandonment** | | | | | | | |
| Total | -49 | -24 | -30 | -103 | -13.5 | -4.5 | 13.5 | 337.5 |
| | (Total $103 MM net capcost & $18 MM opcost not including $20.6 MM abandonment) | | | | | | | |

| Year | *Royalty deprec.* | *Royalty income* | Royalty paid | *Tax depr.* | *Taxable income* | Tax paid | Undisc. ATAX cash flow | 10% disc ATAX cash flow |
|---|---|---|---|---|---|---|---|---|
| 0 | *0* | *0* | 0 | *-13.10* | *-13.10* | 4.32 | -126.68 | -126.68 |
| 1 | *-5.40* | *99.10* | -9.91 | *-13.10* | *79.99* | -26.40 | 66.69 | 60.63 |
| 2 | *-5.40* | *66.60* | -6.66 | *-13.10* | *50.74* | -16.74 | 47.10 | 38.92 |
| 3 | *-5.40* | *46.60* | -4.66 | *-13.10* | *32.74* | -10.80 | 35.04 | 26.32 |
| 4 | *-5.40* | *29.10* | -2.91 | *-13.10* | *16.99* | -5.61 | 24.48 | 16.72 |
| 5 | *-5.40* | *19.10* | -1.91 | *-13.10* | *7.99* | -2.64 | 18.45 | 11.46 |
| 6 | *-5.40* | *11.60* | -1.16 | *-13.10* | *1.24* | -0.41 | 13.93 | 7.86 |
| 7 | *-5.40* | *6.60* | -0.66 | *-13.10* | *-3.26* | 1.08 | 10.92 | 5.60 |
| 8 | *-5.40* | *4.10* | -0.41 | *-13.10* | *-5.51* | 1.82 | 9.41 | 4.39 |
| 9 | *-5.40* | *1.60* | -0.16 | *-10.30* | *-4.96* | 1.64 | 34.98 | 14.83 |
| 10 | *-5.40* | *-5.40* | 0.54 | *2.80* | *3.34* | -1.10 | -0.56 | -0.22 |
| 11 to 17 | *0* | *0* | 0 | *19.60* | *19.60* | -6.47 | -6.47 | -1.70 |
| 18 | *0* | *0* | 0 | *2.80* | *-17.80* | 5.87 | -14.73 | -2.65 |
| Total | *-54.00* | *279.00* | -27.90 | *-103.00* | *168.00* | -55.44 | **112.56** | **55.50** |
| | | | | | | | | **(NPV)** |

Check total royalty paid: 0.1*(337.5-4.5-24-30) = 27.9 --> correct
Check total tax paid: 0.33*(337.5-103-18-20.6-27.9) = 55.44 --> correct
Check total atax NPV undiscounted = 337.5-103-18-20.6-27.9-55.4 = 112.56 --> correct

Summary: For $131 million initial capital, atax NPV = $55.5 million at 10% or $112.6 million undiscounted.
Undiscounted payback time is 2.3 years from the start of oil production.

**APPENDIX 3 - TWO-PAGE PRINTOUT OF CASE 1a SPREADSHEET**

**Definition of Case 1a**

Gas & oil wells with produced water; separation and water disposal facilities on platform except onshore CO2/last separation. No compression offshore; compression onshore from startup. Three separate pipelines to shore (gaslift/injection gas + produced gas & liquid). Assume gas development same as Case 1. Development of oil at 3000 m depth is incremental in terms of costs and liquid production.

**Note: Implicitly assuming (as in Case 1) that onshore facility is near the Geelong Refinery, so minimal oil transport costs. Also assume that government approval is granted to flare low pressure gas on the platform with no government penalty.**

**Case 1a Oil Production assuming 13.5 MMstb recoverable oil in 9 years (as in Case 2a)**
**(25% of 54 MMstb OOIP in a 10 square km area with a 15 metre oil column),**

| Year | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 |
|---|---|---|---|---|---|---|---|---|
| MMstb oil | 4.2 | 2.9 | 2.1 | 1.4 | 1 | 0.7 | 0.5 | 0.4 |

In Case 1a oil production must stop after 8 years to allow wells and well slots to be converted to gas production, so the 0.3 MMstb produced in Year 9 in Case 2a remains unrecovered.
Total oil production in 8 years = 13.2 MMstb from 5 producing wells plus two gas injectors.

**Upstream Capital and Operating Development Costs 1995 Aus $ (Wells)**

CASE 1a incremental compared to Case 1 **(EXCLUDING EXPLORATION COSTS)**

| | | |
|---|---|---|
| OUTLINE | Year 0 - (capital) | $77 MM to drill/complete 5 horizontal wells plus 2 gas injection wells at 3000 m TVD ($12 MM per horizontal well + $8.5 MM per gas injection well) |
| | Yrs 1 to 8 | Opcosts assume $1.5 MM/year for wireline/test/CT/gaslift/reservoir management. |
| | **Year 8 Capex saving:** | In Case 1 (no oil development) spend $60 MM on recompletions & 6 new wells. Assume that 4 of the new wells (each $9 MM) are replaced by $2 MM recompletions from oil producers/gasinjectors, so save $28 MM in Case 1a. |

**Incremental Case 1a pipeline capital costs 1995 Aus $, all incurred in Year 0**

For gas production wells, the same WHP and 16" gas line are assumed as in Case 1. Assume 6" produced liquid line as in Case 2a and a 4" gaslift line. For Case 1a (bigger onshore liquid line to the refinery and 3 offshore lines - one 12", one 6" and one 4") versus Case 1 (minor onshore line + one 16" line offshore at $141 MM): assume $50 MM incremental.

**Incremental Onshore Facility Costs 1995 Aus $, all incurred in Year 0**

In Case 1a assume $5 MM incremental versus Case 1 ($50 MM cost) to account for extra liquids handling and bigger compressor (for gaslift/injection gas back to platform).

**Case 1a Compared to Case 1 - Offshore Facility Costs 1995 Aus $, all incurred in Year 0**

Extra costs for water disposal, higher production rates, 15 well slots instead of 14 and the need to handle widely varying WHPs. Assume incremental $15 MM (not as much as the incremental $21 MM in Case 2a versus Case 2 because there is no incremental compression offshore in Case 1a).

**Case 1a Compared to Case 1 - Downstream Operating Costs**

Minor extra costs for water disposal, higher rates, more compression because of gaslift/injection, and an an extra 5 producing wells. Major incremental cost for flare repairs due to flaring 5 bcf per year on the platform (assuming 1000 scf/bbl GLR). Assume total $1.5 MM per year incremental downstream opcosts.

**Earlier Abandonment of Overall Project and Incremental Costs (Case 1a versus Case 1)**

Because of about 40 bcf of gas flared on the platform, assume that 1 PJ/year sales gas is lost in Years 10 to 15, then the overall project is abandoned after 15 years so sales lost in Years 16 and 17 are 13 and 12 PJ. (Total 31 PJ lost compared to Case 1). Assume that revenue associated with sales gas is $3.5/GJ.
The Case 1 opcosts in Years 16 and 17 (per year $21MM downstream & $4 MM upstream) are saved.
Abandonment costs (assumed at 20% of total capital spent throughout the project) are now incurred in Year 16 - $23.8 MM incremental plus $80.4 MM that would have been spent in Year 18 in Case 1.

**SUMMARY OF INCREMENTAL COSTS FOR CASE 1a VERSUS CASE 1**

| Year | U/S Cap | P/L Cap | Facs Cap | Total Cap | U/S Op | D/S Op | Abandonment | |
|---|---|---|---|---|---|---|---|---|
| 0 | 77 | 50 | 15+ 5 =20 | 147 | 0 | 0 | 0 | |
| 1 to 7 | 0 | 0 | 0 | 0 | 1.5 | 1.5 | 0 | |
| 8 | -28 | 0 | 0 | -28 | 1.5 | 1.5 | 0 | |
| 9 to 15 | 0 | 0 | 0 | 0 | 0 | 0 | | |
| 16 | 0 | 0 | 0 | 0 | -4 | -21 | 23.8+80.4 = 104.2 | |
| 17 | 0 | 0 | 0 | 0 | -4 | -21 | 0 | |
| 18 | 0 | 0 | 0 | 0 | 0 | 0 | -80.4 | |
| **TOTAL** | **49** | **50** | **20** | **119** | **4** | **-30** | **23.8** | |

**SIMPLE APPROXIMATION OF INCREMENTAL ECONOMICS FOR CASE 1a VERSUS CASE 1**

(Fiscal assumptions as in Case 2a, plus assume $3.5 MM revenue associated with each PJ of flared gas).

| Year | Upstream Capital | Facilities Capital | Pipeline Capital | Total Capital | Upstream Opcost | D/stream Opcost | Oil MMStb | Oil & gas revenue |
|---|---|---|---|---|---|---|---|---|
| 0 | -77 | -20 | -50 | -147 | 0 | 0 | 0 | 0 |
| 1 | 0 | 0 | 0 | 0 | -1.5 | -1.5 | 4.2 | 105 |
| 2 | 0 | 0 | 0 | 0 | -1.5 | -1.5 | 2.9 | 72.5 |
| 3 | 0 | 0 | 0 | 0 | -1.5 | -1.5 | 2.1 | 52.5 |
| 4 | 0 | 0 | 0 | 0 | -1.5 | -1.5 | 1.4 | 35 |
| 5 | 0 | 0 | 0 | 0 | -1.5 | -1.5 | 1 | 25 |
| 6 | 0 | 0 | 0 | 0 | -1.5 | -1.5 | 0.7 | 17.5 |
| 7 | 0 | 0 | 0 | 0 | -1.5 | -1.5 | 0.5 | 12.5 |
| 8 | 28 | 0 | 0 | Save 28 | -1.5 | -1.5 | 0.4 | 10 |
| 9 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 to 15 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 6 x 1 x -3.5/year (Lose 1 PJ/yr) |
| 16 | 0 | 0 | 0 | 0 | Save 4 | Save 21 | 0 | 13 PJ * -3.5 / PJ |
| | **In Year 16, also spend $104.2 million incremental expenditure on abandonment** | | | | | | | |
| 17 | 0 | 0 | 0 | 0 | Save 4 | Save 21 | 0 | 12 PJ * -3.5 /PJ |
| 18 | **In Year 18, save $80.4 million expenditure on abandonment compared to Case 1** | | | | | | | |
| Total | -49 | -20 | -50 | -119 | -4 | 30 | 13.2 | 221.5 |
| | Total net revenue = $221.5 million (330 from oil minus 108.5 lost gas revenue). | | | | | | | |

Net incremental costs in $MM are 119 capital, 23.8 abandonment and -26 opcosts ($26 MM opcost saved).

| Year | *Royalty deprec.* | *Royalty income* | Royalty paid | *Tax depr.* | *Taxable income* | Tax paid | Undisc. ATAX cash flow | 10% disc ATAX cash flow |
|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | -14.70 | -14.70 | 4.85 | -142.15 | -142.15 |
| 1 | -7.00 | 96.50 | -9.65 | -14.70 | 77.65 | -25.62 | 66.73 | 60.66 |
| 2 | -7.00 | 64.00 | -6.40 | -14.70 | 48.40 | -15.97 | 47.13 | 38.95 |
| 3 | -7.00 | 44.00 | -4.40 | -14.70 | 30.40 | -10.03 | 35.07 | 26.35 |
| 4 | -7.00 | 26.50 | -2.65 | -14.70 | 14.65 | -4.83 | 24.52 | 16.74 |
| 5 | -7.00 | 16.50 | -1.65 | -14.70 | 5.65 | -1.86 | 18.49 | 11.48 |
| 6 | -7.00 | 9.00 | -0.90 | -14.70 | -1.10 | 0.36 | 13.96 | 7.88 |
| 7 | -7.00 | 4.00 | -0.40 | -14.70 | -5.60 | 1.85 | 10.95 | 5.62 |
| 8 | -7.00 | 1.50 | -0.15 | -11.90 | -5.05 | 1.67 | 36.52 | 17.04 |
| 9 | -7.00 | -7.00 | 0.70 | -11.90 | -11.20 | 3.70 | 4.40 | 1.86 |
| 10 | -7.00 | -10.50 | 1.05 | 2.80 | 0.35 | -0.12 | -2.57 | -0.99 |
| 11 to 15 | 0 | -17.50 | 1.75 | 14.00 | -1.75 | 0.58 | -15.17 | -4.19 |
| 16 | 0 | -25 | 2.45 | 2.80 | -119.45 | 39.42 | -82.83 | -18.03 |
| 17 | 0 | -21 | 2.10 | 2.80 | -12.10 | 3.99 | -10.91 | -2.16 |
| 18 | 0 | 0 | 0 | 0 | 80.40 | -26.53 | 53.87 | 9.69 |
| Total | -70.00 | 181.50 | -18.15 | -119.00 | 86.55 | -28.56 | **57.99** | **28.75** |
| | | | | | | | | **(NPV)** |

Check total royalty paid: 0.1*(221.5+30-20-50) = 18.15 --> correct

Check total tax paid: 0.33*(221.5-119+26-23.8-18.15) = 28.56 --> correct

Check total atax NPV undiscounted = 221.5-119+26-23.8-18.15-28.56 = 57.99 --> correct

SUMMARY: For $147 million initial capital, atax NPV = $28.8 million at 10% or $58.0 million undiscounted.

Undiscounted payback time is 4.0 years from the start of oil production.

# APPENDIX 4 - RFT DATA IN THE 1830m ZONE

Table A4.1 summarises the Yolla 1 RFT operations above 2428m KB. There were two separate groups of runs, the first of which did not have a HP gauge.

The pressure gauges are believed to have been working accurately, although there is concern about the anomaly between strain and HP mud hydrostatic pressures in Run 2. Also there was an offset of 15 psi in the pressures recorded in the different runs. Overall the mud hydrostatic pressures do not lie on the mud gradient line as well as in normal RFT runs (Figure A4.1) because there were continual mud losses to the formation. As stated on the RFT logs, the hole was refilled at irregular intervals throughout the runs.

There was one attempt to sample formation fluid at 1832.5m KB and it seems to have been gas (consistent with other data). No references to this sample have been found in any reports. However, the RFT log summary says that sampling was attempted and the log itself shows 90 minutes of fluid withdrawal after the pretest build-up stabilised in 0.5 minute. The sampling pressure did not increase much during the 90 minute sampling, so the chamber itself did not fill with liquid (otherwise the compression into the chamber would have increased the pressure). Moreover if oil had been recovered it surely would have been noted in 1985 reports and the GOC would not have been estimate at 1832.9m KB.

The permeability was generally fairly low (consistent with core and DST average around 30 md in the reservoir), as evidenced by the low flowing pressures in Table A4.1. The five points attempted from 1807 to 1820m KB indicate no permeability.

The estimated "formation pressures" (many of which were supercharged) are plotted against depth in Figures A4.2, A4.3 and A4.4. The data are scattered, so precise determination of the oil-water contact depth is impossible. Determine of the gas-oil contact depth (somewhere around 1832.9m KB based on logs and DSTs) is not possible to any extent because of the clear supercharging of all points attempted below 1832.5m.

The fluid gradients expected in the reservoir are 1.42 psi/m (1.00 g/cc), 0.884 psi/m (0.6218 g/cc) and 0.253 psi/m (0.178 g/cc) for water, oil and gas respectively. The water density is estimated from the DST 2 water salinity of 30,000 ppm and the Bw of 1.03 rb/stb at reservoir conditions (approximation with some uncertainty due to uncertain dissolved gas content). The oil and gas densities are from the laboratory fluid analyses from DST 2A as discussed in Appendix 5.

It is possible to interpret a water-oil contact as deep as 1856m KB if the following assumptions are made:

- Water gradient line of 1.42 psi/m (as expected from density) through Run 1 point [1868 m, 2763 psia]. As shown on Figure A4.2, this line matches some data but the six points between 1900 and 2220m KB would all have to be supercharged (not unreasonable, especially given the low permeability).

- Oil gradient line through Run 1 points as shown on Figure A4.3. If this is correct the points at 1843 and 1856m KB must be supercharged.

- Oil gradient line through Run 2 points as shown on Figure A4.3 and no Run 2 points in the water zone.

It is also possible to interpret a water-oil contact as shallow as 1841m KB if the following assumptions are made:

- Water gradient line of 1.42 psi/m (based on density) through Run 1 point [1856m, 2753 psia] that does not really match the data. The Figure A4.2 line through this point has a 1.52 psi/m gradient, too high to be valid, and so some of the points must be supercharged. Moreover the [1868, 2768 psia] point lies 7 psi low which is difficult to explain (Figure A4.4).

- Oil gradient lines as shown on Figure A4.4. Run 2 water line through second point at 1845m KB, with 2723 psia.

It is concluded that the OWC is in the vicinity of 1841 to 1856m KB, more likely at the deeper end of the range. Note that theoretically the RFT tool indicates oil gradient in an oil-water transition zone in a water-wet reservoir.

**TABLE A4.1 SUMMARY OF RFT OPERATIONS from 1807-2428 m KB - YOLLA 1**

**Suite 3 Run 1 - Noon 24th to Noon 25th August 85**

| DEPTH (m KB MD) | Strain Mud hydrostatic P (psia) | HP Mud hydrostatic P (psia) | Strain Formation P (psia) | HP Formation P (psia) | Flow P (psig) | Mins to get to res P | REMARKS (assume 12 secs per line on log) |
|---|---|---|---|---|---|---|---|
| 1819.2 | 3023 | N/A | N/A | N/A | 8 | N/A | Tight; no buildup. |
| 1818.0 | 3024 | N/A | 2747 | N/A | <11 | 7.0 | Definitely supercharged. |
| 1833.0 | 3052 | N/A | 2755+ | N/A | <10 | >12 | Definitely supercharged. |
| 1832.5 | 3054 | N/A | 2722 | N/A | 12 | <0.5 | Sample for 90 mins at 115 psig. Similar notes apply as for 1832.7 run 2. Appears Valid P. |
| 1838.0 | 3064 | N/A | N/A | N/A | <11 | N/A | Lost seal |
| 1839.0 | 3067 | N/A | 2732 | N/A | <11 | 0.5 | Appears Valid P. |
| 1843.0 | 3073 | N/A | 2739 | N/A | 11 | 2.0 | Maybe slight supercharging |
| 1846.5 | 3080 | N/A | 2740 | N/A | 11 | 1.0 | Appears Valid P. |
| 1856.0 | 3095 | N/A | 2753 | N/A | 10 | 1.5 | Appears Valid P. |
| 1868.0 | 3108 | N/A | 2763 | N/A | < 9 | 1.0 | Appears Valid P. |
| 1905.0 | 3177 | N/A | 2836 | N/A | 16 | c. 30 | Definitely supercharged. |
| 1921.0 | 3207 | N/A | 2850 | N/A | 19 | 1.0 | Appears Valid P. |
| 1946.0 | 3249 | N/A | 2888 | N/A | 20 | 1.0 | Appears Valid P. |
| 2034.0 | 3396 | N/A | 3020 | N/A | 24 | 1.0 | Appears Valid P. |
| 2125.0 | 3551 | N/A | 3160 | N/A | 34 | 1.0 | Appears Valid P. |
| 2215.0 | 3705 | N/A | 3299 | N/A | 40 | >1 | Lost seal after 2 mins when only built up to 3252 psi, so quite tight. Regained seal and P settled around 3299 psia , but questionable. |
| 2327.0 | 3854 | N/A | 3415 | N/A | <4 | 2.0 | Possibly valid P though FBHP low |
| 2428.0 | 4015 | N/A | 3556 | N/A | <1 | <0.5 | Possibly valid P though FBHP low |

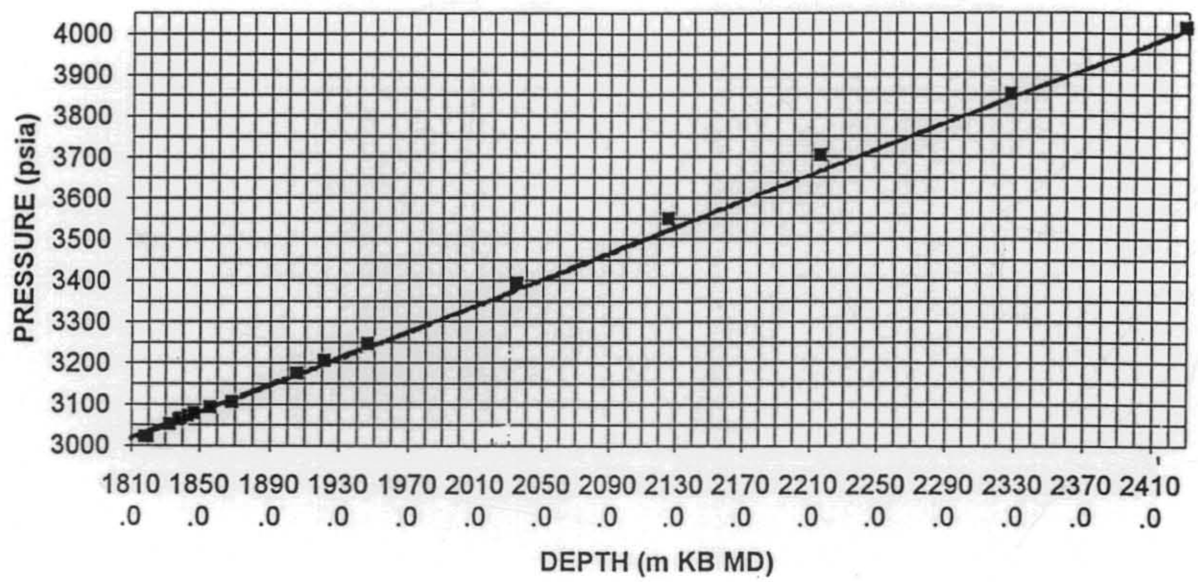
**Suite 3 Run 2 - 31 August 1985**

| DEPTH (m KB MD) | Strain Mud hydrostatic P (psia) | HP Mud hydrostatic P (psia) | Strain Formation P (psia) | HP Formation P (psia) | Flow strain (psig) | Mins to get to res P | REMARKS |
|---|---|---|---|---|---|---|---|
| 1845.0 | 3136 | 3143 | 2726 | 2726 | <18 | 0.8 | Appears Valid P |
| 1820.0 | 3090 | 3097 | N/A | N/A | <1 | N/A | Tight; no buildup. |
| 1832.7 Best porosity according to sonic log. | 3112 | 3118 | 2708 | 2710 | c.2400 | 1.5 | Valid P. High perm. This depth (3 pressures taken 1832.5 run 1 + 1832.7 & 1833 Run 2) used by Amoco in 1985 to define Reservoir Pressure (in advice to Corelab reported in DST 2A Fluid analysis report Page 1 of 35). |
| 1807.0 | 3081 | 3068 | N/A | N/A | <7 | N/A | Tight; no buildup. |
| 1814.0 | 3096 | 3083 | N/A | N/A | <11 | N/A | Tight; no buildup. |
| 1820.0 | 3110 | 3095 | N/A | N/A | <13 | N/A | Lost seal. Showed low (maybe 0) perm before the seal was lost |
| 1826.8 | 3125 | 3110 | N/A | N/A | N/A | N/A | Lost seal |
| 1830.0 | 3125 | 3110 | 2728 | 2713 | c. 1800 | c. 10 | Fair perm but supercharged |
| 1832.0 | 3110 | 3105 | N/A | N/A | N/A | N/A | Lost seal |
| 1833.0 | 3115 | 3114 | 2710 | 2710 | c. 2600 | 0.5 | Valid P. High perm. Similar notes apply as for 1832.7 run 2. |
| 1837.0 | 3120 | 3120 | 2713 | 2713 | c. 2400 | 0.5 | Appears valid P. High perm. |
| 1845.0 | 3133 | 3133 | 2723 | 2723 | c. 2400 | 0.8 | High perm. Appears valid P. |

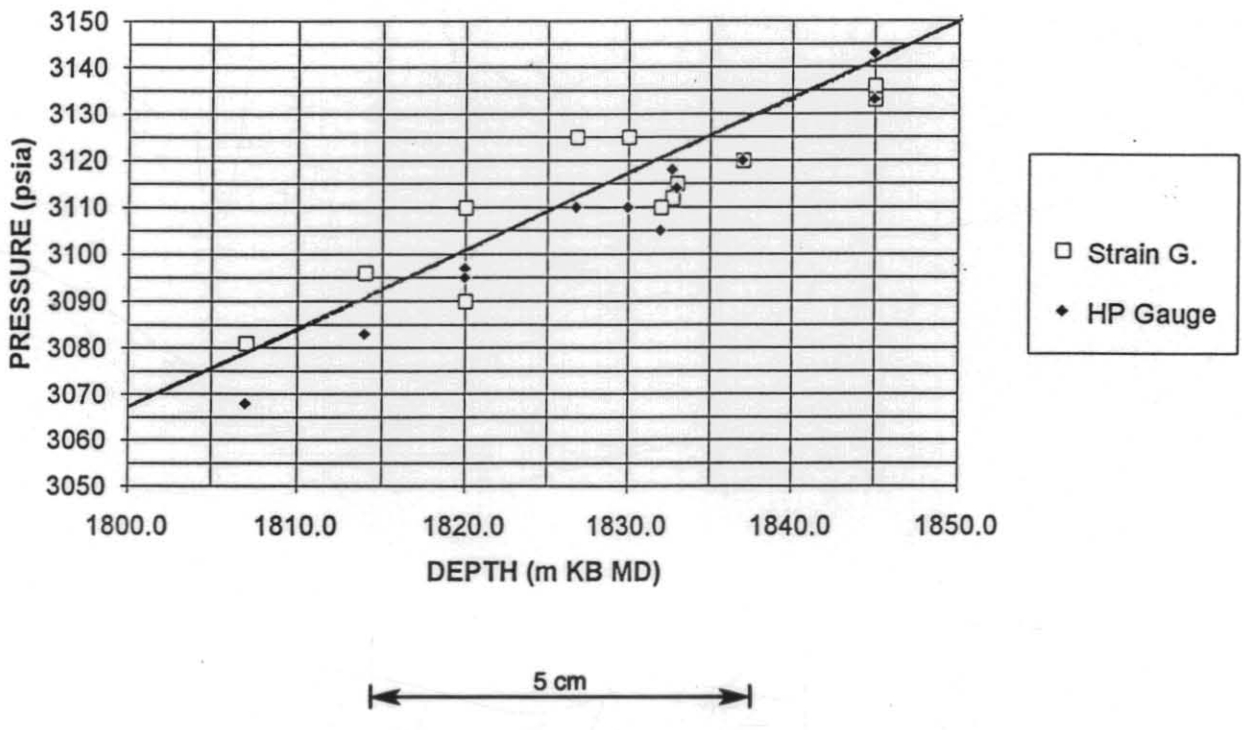
Note: 1) Where perm is sufficient to get drawdown, fluid withdrawal = 20 cc (inherent in RFT).
2) Strain gauge P originally recorded in psig. Above numbers in psia (15 psi added).

FIGURE A4.1

MUD HYDROSTATIC YOLLA 1 RFT RUN 1 (STRAIN GAUGE)




MUD HYDROSTATIC YOLLA 1 RFT RUN 2




Lines on graphs have 1.65 psi/m gradient as expected from 9.8 ppg mud weight.

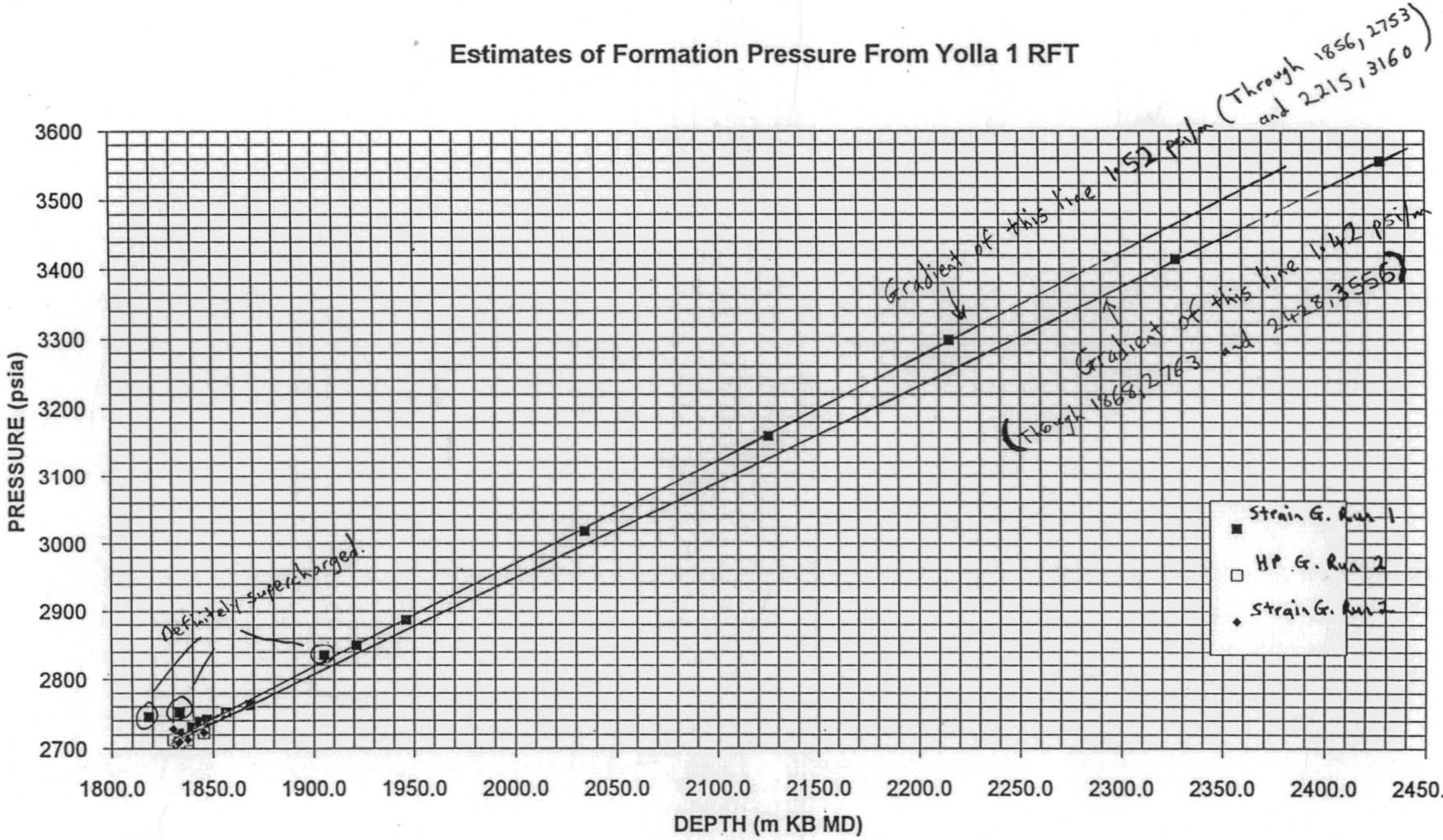


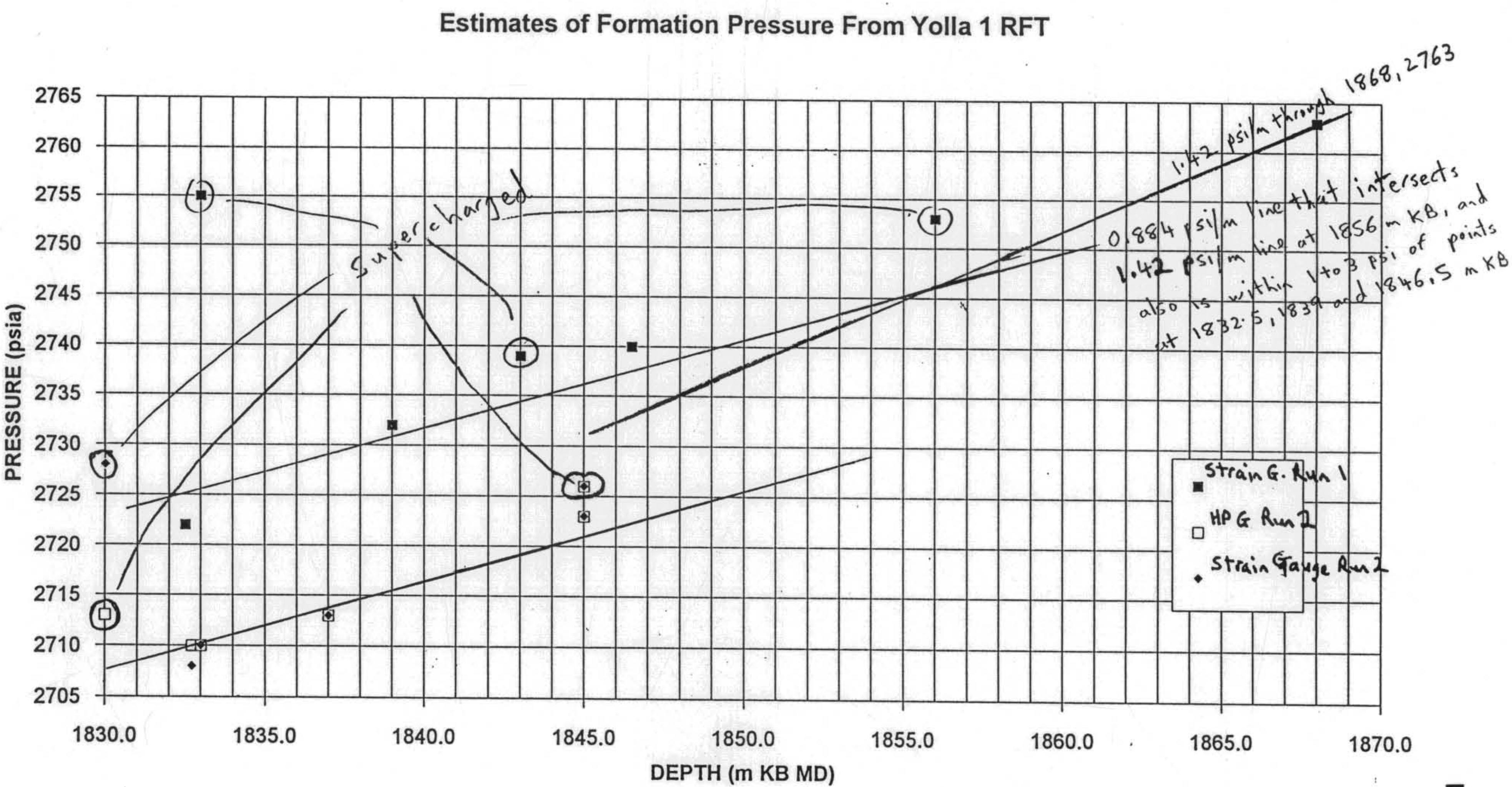

FIGURE A4.2

**NOTE: Based on water density, the water gradient is approximately 1.42 psi/m**

5 cm

513053

RFT INTERPRETATION WITH ASSUMPTIONS NECESSARY TO CONCLUDE OWC AROUND 1856 m KB




5 cm

FIGURE A4.3

513054

## RFT INTERPRETATION WITH ASSUMPTIONS NECESSARY TO CONCLUDE OWC AROUND 1841 m KB

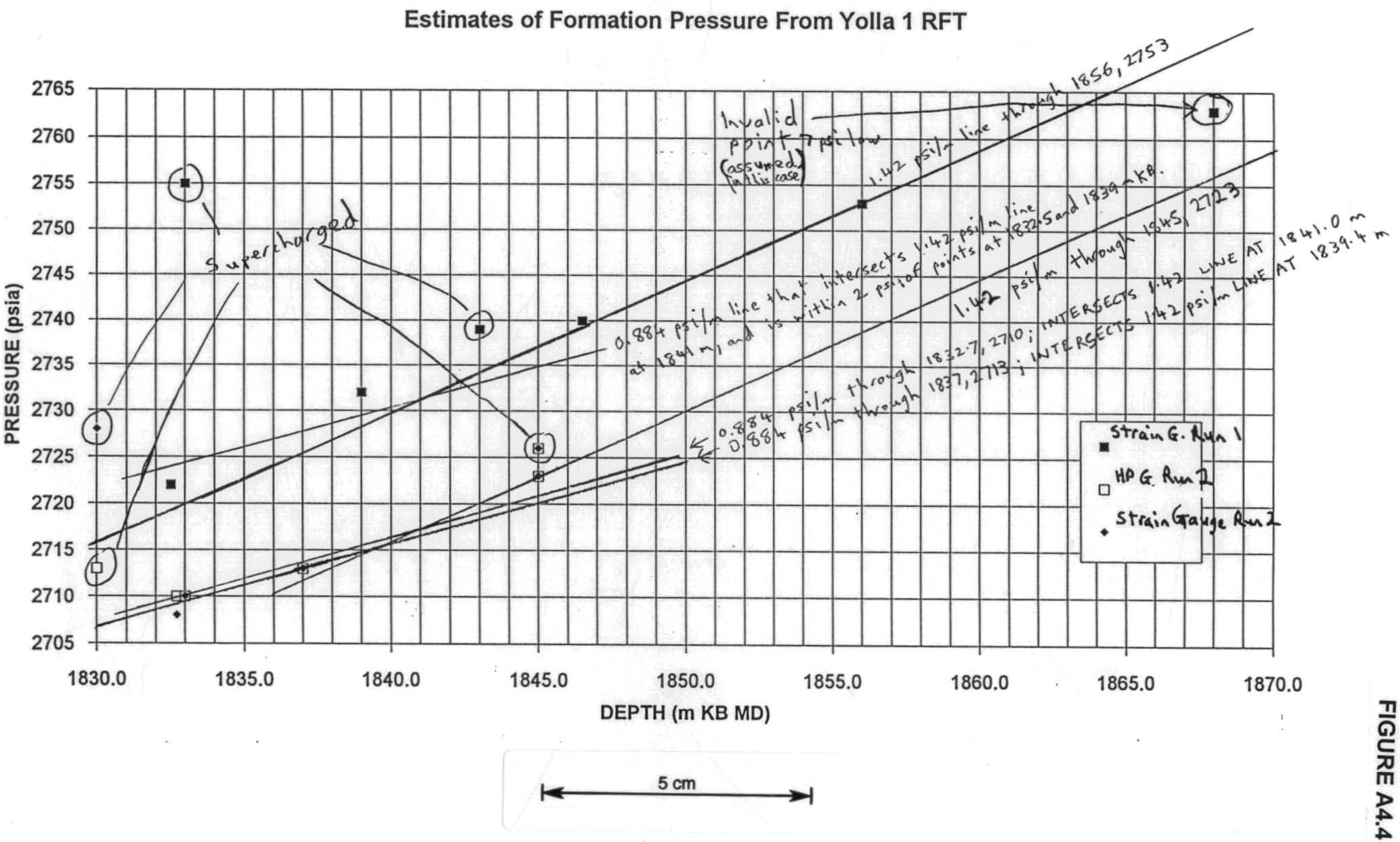



FIGURE A4.4

513055

## APPENDIX 5 - DST DATA IN THE 1830m ZONE

Three DSTs were conducted in the Yolla 1 "1830m Zone" with the following results:

**DST 2:** Interval 1830-1835.2m KB. Flowed 2.2 MMscf/d of gas, RTSTM oil/condensate and 1675 bpd of water. The water was channelling from other interval(s) in the well behind the casing, where there was little or no cement.

**DST 2A:** Interval 1833.2-1833.8m KB (after several cement squeezes). Flowed 1.0 MMscf/d of gas, 302 stb/d of oil/condensate and no water.

**DST 3:** Interval 1813-1833.8m KB. Flowed 11.8 Mmscf/d of gas, 892 stb/d of oil/condensate and no water.

A PLT run during DST 3 showed that all the flow was coming from the bottom 2 to 3 metres, corresponding to about 1831 to 1838.8m KB. This result, together with logs and RFT data, confirms that there is no pay contributing above 1829.2m KB.

The amounts and properties of liquid and free gas flowing in the reservoir in DSTs 2A and 3 can be estimated by the using the DST 2A fluid analysis by Corelab. Corelab recombined separator liquid and gas in the produced ratio and determined a saturation pressure at 209°F (reservoir temperature) of 4969 psia, way above the true bubblepoint because of gas cap gas. Then the fluid was equilibrated at reservoir conditions (2710 psia and 209°F). Some properties of the equilibrated liquid and gas, representative of the reservoir oil leg liquid and gas cap gas, are shown in Table A5.1. The reported flows in DSTs 2A and 3 correspond to:

| DST | Reservoir Liquid rb/day | Oil from Liquid stb/day | Associated gas MMscf/d | Reservoir Free Gas MMscf/d | Condensate stb/day | Total oil/cond stb/day | Total gas MMscf/d |
|---|---|---|---|---|---|---|---|
| 2A | 476 | 294 | 0.28 | 0.74 | 8 | 302 | 1.02 |
| 3 | 1254 | 776 | 0.73 | 11.1 | 116 | 892 | 11.83 |

These flows may be used to calculate productivity indices and order of magnitude contributing permeability thickness (kh). The steady-state equations with zero skin give:

Order of magnitude liquid kh = (Productivity in rb/day/psi) x 0.27 cp x 141.2 x 7.5

$$\text{Order of magnitude gas kh} = \frac{(\text{Free gas q in MMscf/d}) \times (\mu \text{ in cp}) \times Z \times (T \text{ in } {}^\circ R) \times \ln (r_e/r_w)}{10^{-6} \times 0.7078 \times (\text{Reservoir } P^2 - \text{FBHP}^2)}$$

$$= \frac{q \times 0.02 \times 0.8 \times 669 \times 7.5}{10^{-6} \times 0.7078 \times (2710^2 - \text{FBHP}^2)}$$

| DST | FBHP at reported flows (psia) | Drawdown (2710-FBHP) (psi) | Reservoir Liquid Productivity (rb/day/psi) | Reservoir Liquid kh (md-ft) | Free Gas Productivity (MMscf/day/psi) | Reservoir Free Gas kh (md-ft) |
|---|---|---|---|---|---|---|
| 2A | 1872 | 838 | 476/838 = 0.57 | 163 | 0.74/838 = 0.00088 | 22 |
| 3 | 1364 | 1346 | 1254/1346 = 0.93 | 266 | 11.1/1364 = 0.0081 | 230 |

These data suggest that DST 2A was perforated in the oil leg, with gas coning, and the added perforations for DST 3 were mainly in the gas cap. The 63% increase in reservoir liquid productivity in DST 3 may be explained by:

- The well may have been cleaning up.
- The effective permeability to oil in DST 3 may have been higher because gas cap gas was going directly into the well rather than coning down through the oil.
- Some of the added perforations were at the top of oil leg (about 1832.9 to 1833.2m KB).

In DST 3 the contributing oil pay is interpreted to be from 1832.9m KB (the assumed GOC) to 1834.4m KB, the top of a 0.6m tight section indicated by the MSFL log. The gas pay is (1832.9m - 1829.2m - 0.5m non pay). Therefore, oil h is 1.5 metres and gas h is 3.2m. Since the sand is tighter at the top, this interpretation of contributing pay is consistent with the similar liquid and gas kh values calculated above for DST 3.

DST 2A is the best test for checking the estimated oil leg kh using pressure transient data because the liquid phase dominated. The 1985 Thomas Report performed a valid semilog build-up analysis resulting in a slope of m = 122 psi/cycle and $P_{1\ hr}$ = 2550 psia. Results are then:

| | 1985 Thomas Report | Updated Values in this Report |
|---|---|---|
| Assumed reservoir liquid rate (rb/day) | 302 x 1.46 = 441 | 476 |
| Assumed viscosity (cp) | 0.3 | 0.27 |
| Assumed $c_t$ ($psi^{-1}$) | $109 \times 10^{-6}$ | $109 \times 10^{-6}$ |
| Assumed h (feet) | 28 (down to the assumed OWC) | 5 (1.5 metres to tight section on logs) |
| Assumed Porosity | 0.3 | 0.25 |
| $r_w$ (feet) | 0.51 | 0.51 |
| FBHP (psia) | 1872 | 1872 |
| Calculated Kh (md-ft) (standard equation) | 176.3 | 171.2 |
| Calculated K (md) | 6.3 | 34 |
| Calculated S | +2.8 | +1.8 |

**TABLE A5.1** **FLUID PROPERTIES IN THE 1830 m ZONE - YOLLA 1 DST 2A FLUID**

The separator samples recovered from DST 2A (1833.2 to 1833.8 m KB) were recombined in the laboratory by Corelab (1985 report) and equilibrated at the known in situ saturation pressure (2710 psia original reservoir pressure at 209 degrees F). The equilibrium liquid phase represents reservoir oil while the gas phase represents gas cap gas.

Many analyses were performed on the equilibrium liquid and gas, including depletion studies as detailed in the 1985 report. A summary of results at original reservoir conditions is:

| | Gas phase |
|---|---|
| Formation volume factor | 0.00594 rcf/scf |
| z factor | 0.850 |
| Viscosity | 0.0217 cp |
| Condensate recovered at the primary stage (90 psig and 102 degs F) | 10.38 stb (61.3 degs API gravity) |
| Total plant products in primary separator gas (gallons per MMscf) | Ethane : 2735<br>Propane : 1828<br>Butanes : 1072<br>Pentanes+: 902 |
| Total plant products in reservoir gas (gallons per MMscf) | Ethane : 2739<br>Propane : 1839<br>Butanes : 1047<br>Pentanes+: 1335 |

| | Oil phase |
|---|---|
| Formation volume factor | 1.617 rb/stb with 2 separator stages (90 and 0 psig) at 102 degs F. |
| Stock tank oil gravity | 45.8 degs API |
| Viscosity | Not measured |
| Gas recovered at the primary stage (90 psig and 102 degs F) | 940 scf/stb |
| Gas recovered at the second stage (0 psig and 102 degs F) | 90 scf/stb |

The original oil viscosity was calculated using correlations to be 0.27 cp.

**APPENDIX 6 - TWO-PAGE PRINTOUT OF CASE 2b SPREADSHEET**

**Definition of Case 2b**

Gas & oil wells with produced water; separation/compression/water disposal facilities on platform except onshore $CO_2$/last separation; two separate pipelines to shore (gas & liquid). Assume gas development same as Case 2. Development of oil&gas at 1830 m depth is incremental in terms of costs and liquid production. Assume no incremental gas production after incremental fuel use.

**Note: Implicitly assuming (as in Case 2) that onshore facility is near the Geelong Refinery, so minimal oil transport costs, and have compressor offshore for gaslift.**

**Case 2b Oil Production with 8.4 MMstb reserves (6 wells x 1.4 MMstb discussed in Section 13).**
**Start 6000 bopd, 10% downtime and end 600 bopd (9 years @ 25% decline after 1 year plateau).**

| Yearly decline | Rate at start of year | Rate at end of year | Av oil rate in yr | Yearly Mstb | Cum Mstb | Year | Rounded MMstb oil per year |
|---|---|---|---|---|---|---|---|
| 25% | 6,000 | 6000 | 5400 | 1971 | 1971 | 1 | 2 |
| 75% | 6000 | 4500 | 4725 | 1724.625 | 3695.625 | 2 | 1.8 |
| | 4500 | 3375 | 3543.75 | 1293.469 | 4989.094 | 3 | 1.3 |
| | 3375 | 2531.25 | 2657.813 | 970.1016 | 5959.195 | 4 | 1 |
| | 2531.25 | 1898.4375 | 1993.359 | 727.5762 | 6686.771 | 5 | 0.8 |
| | 1898.4375 | 1423.8281 | 1495.02 | 545.6821 | 7232.454 | 6 | 0.6 |
| | 1423.82813 | 1067.8711 | 1121.265 | 409.2616 | 7641.715 | 7 | 0.4 |
| | 1067.87109 | 800.90332 | 840.9485 | 306.9462 | 7948.661 | 8 | 0.3 |
| | 800.90332 | 600.67749 | 630.7114 | 230.2096 | 8178.871 | 9 | 0.2 |
| | | | | | | | 8.4 |

**Upstream Capital and Operating Development Costs 1995 Aus \$ (Wells)**

CASE 2b incremental compared to Case 2 **(EXCLUDING EXPLORATION COSTS)**

| | | |
|---|---|---|
| OUTLINE | Year 0 - (capital) | \$40 MM to drill/complete 5 horizontal wells at 1830 m TVD (\$8 MM each) |
| | Yrs 1 to 9 | Opcosts assume \$1 MM/year for wireline/test/CT/gaslift/reservoir management. |
| | **Year 9 Capex saving:** | In Case 2 (no oil development) spend \$60 MM on recompletns & 6 new wells. Assume that 3 of the new wells (each \$9 MM) are replaced by \$6 MM plug back & deepening from 9-5/8" part of horizontal wells, so save \$9 MM in Case 2b. |

**Incremental Case 2b pipeline capital costs 1995 Aus \$, all incurred in Year 0**

Case 2b (bigger onshore liquid line to the refinery and 2 offshore lines - one 12" other 6") versus Case 2 (minor onshore line + one 12" line offshore at \$85 MM): assume \$30 MM incremental as in Case 2a.

**Incremental Case 2b Onshore Facility Costs 1995 Aus \$, all incurred in Year 0**

In Case 2b assume \$2 MM incremental versus Case 2 (\$30 MM cost) to account for extra liquids handling.

**Case 2b Compared to Case 2 - Offshore Facility Costs 1995 Aus \$, all incurred in Year 0**

Extra costs for water disposal, higher production rates, more compression because of gaslift and the need to handle widely varying WHPs. Assume incremental 10% (equal to \$14 MM) vs Case 2 (\$138 MM cost).

**Case 2b Compared to Case 2 - Downstream Operating Costs**

Minor extra costs for water disposal, higher production rates, more compression because of gaslift and and an extra 6 producing wells. Assume incremental \$0.5 MM per year versus Case 2.

**Abandonment Costs (Case 2b incremental versus Case 2)**

Assume 20% of total incremental capital spent throughout the project.
Assume that this cost is incurred in Year 18, along with the abandonment of the gas development (Case 2).

**SUMMARY OF INCREMENTAL COSTS FOR CASE 2b VERSUS CASE 2**

| Year | U/S Cap | P/L Cap | Facs Cap | Total Cap | U/S Op | D/S Op | Abandonment |
|---|---|---|---|---|---|---|---|
| 0 | 40 | 30 | 14+ 2 =16 | 86 | 0 | 0 | 0 |
| 1 to 8 | 0 | 0 | 0 | 0 | 1 | 0.5 | 0 |
| 9 | -9 | 0 | 0 | -9 | 1 | 0.5 | 0 |
| 10 to 17 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 18 | 0 | 0 | 0 | 0 | 0 | 0 | 15.4 |
| **TOTAL** | **31** | **30** | **16** | **77** | **9** | **4.5** | **15.4** |

**SIMPLE APPROXIMATION OF INCREMENTAL ECONOMICS FOR CASE 2b VERSUS CASE 2**

(Fiscal assumptions as in Case 2a).

| Year | Upstream Capital | Facilities Capital | Pipeline Capital | Total Capital | Upstream Opcost | D/stream Opcost | Oil MMStb | Oil revenue |
|---|---|---|---|---|---|---|---|---|
| 0 | -40 | -16 | -30 | -86 | 0 | 0 | 0 | 0 |
| 1 | 0 | 0 | 0 | 0 | -1 | -0.5 | 2 | 50 |
| 2 | 0 | 0 | 0 | 0 | -1 | -0.5 | 1.8 | 45 |
| 3 | 0 | 0 | 0 | 0 | -1 | -0.5 | 1.3 | 32.5 |
| 4 | 0 | 0 | 0 | 0 | -1 | -0.5 | 1 | 25 |
| 5 | 0 | 0 | 0 | 0 | -1 | -0.5 | 0.8 | 20 |
| 6 | 0 | 0 | 0 | 0 | -1 | -0.5 | 0.6 | 15 |
| 7 | 0 | 0 | 0 | 0 | -1 | -0.5 | 0.4 | 10 |
| 8 | 0 | 0 | 0 | 0 | -1 | -0.5 | 0.3 | 7.5 |
| 9 | 9 | 0 | 0 | Save 9 | -1 | -0.5 | 0.2 | 5 |
| 10 to 17 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 18 | **In Year 18, $15.4 million incremental expenditure on abandonment** | | | | | | | |
| Total | -31 | -16 | -30 | -77 | -9 | -4.5 | 8.4 | 210 |
| | (Total $77 MM net capcost & $13.5 MM opcost not including $15.4 MM abandonment) | | | | | | | |

| Year | *Royalty deprec.* | *Royalty income* | Royalty paid | *Tax depr.* | *Taxable income* | Tax paid | Undisc. ATAX cash flow | 10% disc ATAX cash flow |
|---|---|---|---|---|---|---|---|---|
| 0 | *0* | *0* | 0 | *-8.60* | *-8.60* | 2.84 | -83.16 | -83.16 |
| 1 | *-4.60* | *44.90* | -4.49 | *-8.60* | *35.41* | -11.69 | 32.32 | 29.39 |
| 2 | *-4.60* | *39.90* | -3.99 | *-8.60* | *30.91* | -10.20 | 29.31 | 24.22 |
| 3 | *-4.60* | *27.40* | -2.74 | *-8.60* | *19.66* | -6.49 | 21.77 | 16.36 |
| 4 | *-4.60* | *19.90* | -1.99 | *-8.60* | *12.91* | -4.26 | 17.25 | 11.78 |
| 5 | *-4.60* | *14.90* | -1.49 | *-8.60* | *8.41* | -2.78 | 14.23 | 8.84 |
| 6 | *-4.60* | *9.90* | -0.99 | *-8.60* | *3.91* | -1.29 | 11.22 | 6.33 |
| 7 | *-4.60* | *4.90* | -0.49 | *-8.60* | *-0.59* | 0.19 | 8.20 | 4.21 |
| 8 | *-4.60* | *2.40* | -0.24 | *-8.60* | *-2.84* | 0.94 | 6.70 | 3.12 |
| 9 | *-4.60* | *-0.10* | 0.01 | *-7.70* | *-4.19* | 1.38 | 13.89 | 5.89 |
| 10 | *-4.60* | *-4.60* | 0.46 | *0.90* | *1.36* | -0.45 | 0.01 | 0.00 |
| 11 to 17 | *0* | *0* | 0 | *6.30* | *6.30* | -2.08 | -2.08 | -0.55 |
| 18 | *0* | *0* | 0 | *0.90* | *-17.50* | 5.78 | -12.63 | -2.27 |
| Total | *-46.00* | *159.50* | -15.95 | *-77.00* | *85.15* | -28.10 | **57.05** | **24.17** |
| | | | | | | | | **(NPV)** |

Check total royalty paid: 0.1*(210-4.5-16-30) = 15.95 --> correct

Check total tax paid: 0.33*(210-77-13.5-18.4-15.95) = 28.10 --> correct

Check total atax NPV undiscounted = 210-77-13.5-18.4-15.95-28.1 = 57.05 --> correct

SUMMARY: For $86 million initial capital, atax NPV = $24.2 million at 10% or $57.1 million undiscounted.

Undiscounted payback time is 4.1 years from the start of oil production.

# APPENDIX 7

## DISTANCE TO FAULT DETECTABLE FROM WELL TEST PRESSURE TRANSIENT

**Assume**

- D.J. Pridie's formula for order of magnitude distance that barrier can be detected ("Designing Flow/Buildup Tests to Measure Distances to Single Linear No-Flow Boundaries," Canterra Energy Ltd, 1987. SPE Paper 16447):

| | | |
|---|---|---|
| L | = | $(1.48 \times 10^{-4} \times kt \times$ A factor around $0.1 \div \phi\mu c_t)^{1/2}$ |
| k | = | 300 md permeability |
| t | = | 168 hours |
| $\phi$ | = | 0.2 porosity |
| $\mu$ | = | 0.027 cp viscosity |
| $c_t$ | = | $250 \times 10^{-6}$ vol/vol/psi total compressibility |

**Result**

L = 743 feet substituting in equation.

**Conclusion**

With a 7 day extended flow followed by a 7 day buildup, a barrier up to 230 metres from the well could be detected assuming rock and fluid properties as in Yolla 1 DST 1 (2900m zone).

OR-0413

ENCLOSURE

KMP9412018-HLP

513062

**MEMO TO** : R G NEUMANN

**COPY TO** : A M STOCK, R J WILLINK, R LOVIBOND, R J SUTTILL, T SCHOLEFIELD, A WALDRON

**FROM** : H L PARVAR

**DATE** : 14 DECEMBER 1994

**FILE NO** : BA-YOLLA1

**SUBJECT** : **YOLLA 1 RFT**

---

## INTRODUCTION

Yolla 1 was drilled by Amoco Australia Petroleum Company in T/RL1 Licence of the Bass Basin, offshore Tasmania. The well encountered hydrocarbon in the N. Aspersus Paleo and L. Balmei Zones of the Eastern View Coal Measures (EVCM) Formation. Open hole logs and RFT were run and DSTs were conducted to evaluate the hydrocarbon bearing zones within the EVCM Formation. The DST results can be summarised as follows:

**N. Aspersus:** The well intersected gas, oil and water within the N. Aspersus Paleo Zone. Three DSTs were conducted within this zone.

**DST 2:** This DST was conducted within 1830-1835.2m KB interval. The reported gas and water flow rates during the second flow period were 2.2 MMscf/day and 1675 BBLS/day respectively using $^{32}/_{64}$. choke size. The produced water was suspected to be extraneous channelling behind the casing.

**DST 2A:** This test was conducted within the 1833.2 to 1833.8m KB interval. The gas and oil rates using $^{16}/_{64}$. choke size were 1.02 MMscf/day and 302 STB/day respectively. There was no water production during this DST.

**DST 3:** This test was conducted within the 1813 to 1833.1m KB interval. The gas and oil + condensate flow rates using $^{80}/_{64}$. choke size were 11.8 MMscf/day and 892 STB/day respectively. There was no water production during this DST.

Based on the above DST results it is expected that an OWC within the N. Aspersus Zone probably lies below 1833.8m KB with one possibility being that it lies as high as 1833.8 to 1835.2m KB.

**L. Balmei:** The well encountered wet gas within the palaeocene section of the EVCM Formation. At least three separate zones are interpreted as gas bearing within the L. Balmei level. No fluid contacts were detected within this section. DST 1 conducted over the 2809.1 to 2824.6m KB interval produced gas at a rate of 15.1 MMscf/day (condensate rate was 580 BBLS/day) using $^{40}/_{64}$. choke size. There was no water production during the test.

Two RFT runs were conducted in Yolla 1 to evaluate the hydrocarbon zones within the EVCM Formation.

Run 1 was conducted on 25 August 1985 using a strain gauge for pressure measurements. Data recovered from run 1 is shown in Table 1.

There were 68 attempts to set the RFT tool and to test the formation from which 34 tests were successful, 7 tests were tight and the seal failed 27 times. Generally most of the successful tests had high drawdown differential pressure.

Run 2 was conducted on 31 August 1985. The HP gauge was used for pressure measurements during Run 2. Data related to run 2 is presented in Table 2. From the 33 attempts to set the tool and to test the formation, 13 tests were successful, 3 tests were tight and seal failure occurred 9 times. Generally most of the tests had very low drawdown differential pressure.

## INTERPRETATION

Table 1 and 2 show RFT data for Run 1 and 2. As mentioned above, most of the tests conducted during Run 1 showed very high drawdown differential pressure while the tests from Run 2 had very low drawdown differential pressure. The HP gauge used during Run 2 has a higher accuracy and resolution in comparison to strain gauge (Run 1) and it is likely that the data collected during Run 2 (HP gauge data) is more reliable that the data from Run 1 (strain gauge data).

Figure 1 shows the mud hydrostatic pressure of the RFT data for both the strain and HP gauges. The lines fitted through the points represent a mud gradient of 9.8 ppg. As can be seen in this plot there are shifts in the hydrostatic pressure from the top of the EVCM Formation to the L. Balmei level for both the HP gauge (+70 psi) and the strain gauge (-92 psi). If these shifts can be related to gauge performances (which is one possibility) then the RFT pressure data for both the upper and lower zones in the EVCM Formation will be questionable. Under this condition also relating the hydrodynamic pressure of the upper zone to the lower section (without applying proper correction factor) will be incorrect. This is only one of a few possibilities to explain the data however, the unusual hydrostatic data does reduce the level of confidence of the RFT results. In the following interpretation it has been assumed that the shifts are not gauge related problems.

Figure 2 is a plot of the RFT pressure profile showing data from both the N. Aspersus and L. Balmei levels. The profile is generated based on the HP gauge data while the strain gauge data is plotted for comparison. The water line in this plot is drawn based on the RFT data from the upper section (N. Aspersus level).

Figure 2A is an enlarged view of the top section. Based on the expected lowest known hydrocarbon at this level (below 1833.8m KB from the DST results) there are only three HP pressure points that could be located in the water zone. The point at 1845m KB (2725.7 psia) appears to be slightly supercharged. A water line with a slope of 0.433 psi/ft (based on the King 1 RFT data) is fitted through the points (1845m KB, 2722.4 psia) and (1837 MKB, 2712.8 psia). This line has been extended to the lower section as a possible water line in the L. Balmei level.

Figure 2B is the enlarged view of the lower section. The water line is extended from the upper level. Three gas lines with 0.115 psi/ft gradient (based on the DST 1 fluid sample) have been fitted through the HP pressure data. The point at 2724m KB (4126 psia) which does not fit the upper most line has low permeability in comparison with the other points which have excellent to very good permeability.

The RFT pressure data suggests that at least three separate zones exist within the L. Balmei level. The indicated GWC levels for Zones 1 to 3 are 2884m KB, 2925m KB and 3031m KB respectively assuming the zones do not contain oil legs.

## PREVIOUS WORK

The Yolla 1 RFT data have been interpreted previously by Amoco, BMR and recently Enron. The main difference between the various interpretations lies in the methodology for establishing a water line for the L. Balmei level.

**Amoco:** Amoco used a water gradient of 0.44 psi/ft (based on log derived salinity) and the intercept of zero psig at mean sea level (based on the assumption that the formation probably subcrops into the sea bed) to establish a water gradient for the L. Balmei level. Amoco used a gas gradient of 0.115 psi/ft (based on the DST 1 fluid analysis) and RFT data from the HP gauge to draw the gas lines.

Based on the above, Amoco identified three separate gas columns at 2913, 2961 and 3064m KB. It is significant that seismic flat spots observed on 2D seismic lines to the south-west of the structure broadly support the fluid contacts assessed by Amoco. However, uncertainties due to the velocity interpretation does not give a high level of confidence to the results.

**BMR:** BMR used a water gradient of 0.433 psi/ft and the RFT pressure data from the HP gauge. BMR generated a water line in the upper section and extended it to the L. Balmei level using a gas gradient of 0.104 psi/ft to construct the gas lines.

Based on the above, BMR identified four separate gas zones within the L. Balmei level. The BMR calculated gas water contacts fell below the spill point of the structural map provided by Amoco and, consequently, BMR used the mapped spill point as the contact level.

**ENRON:** ENRON used a water gradient of 0.442 psi/ft and RFT data from both the HP and strain gauges (with stress on the strain gauge data). ENRON also constructed a water line in the upper section and extended it to the L. Balmei level and used a gas gradient of 0.087 psi/ft to generate the gas lines.

ENRON identified four separate gas columns in the L. Balmei with fluid contact levels at about 54 metres shallower than the Amoco figures.

## CONCLUSION AND RECOMMENDATION

No fluid contacts can be identified unambiguously at the L. Balmei level of the EVCM Formation in Yolla 1. SAGASCO have attempted to construct a line of best fit through available water points by honouring all available data to establish potential GWCs. The water line thus constructed in the top of the EVCM Formation uses a water gradient of 0.433 psi/ft and RFT data from the HP gauge. The line was extended to the L. Balmei level to be used as the water line for this section. A gas gradient of 0.115 psi/ft was used to construct the hydrodynamic pressure profile for the L. Balmei level. At least three separate hydrocarbon columns were identified in the L. Balmei section with the fluid contact levels at 2884m KB, 2925m KB and 3031m KB respectively assuming the zones do not contain any oil legs.

Based on SAGASCO's best estimate as outlined above and in light of the uncertainties and the work performed by Amoco and ENRON, it is recommended to incorporate the following range of probability into reserve calculations.

| | ***LOW SIDE*** **(ENRON)** | ***MOST LIKELY*** **(SAGASCO)** | ***HIGH SIDE*** **(AMOCO)** |
|---|---|---|---|
| Zone 1 | 2859m KB | 2884m KB | 2913m KB |
| Zone 2 | 2907m KB | 2925m KB | 2961m KB |
| Zone 3 | 3010m KB | 3031m KB | 3064m KB |

Obviously the LKG and spill point levels should be still used for proven and possible cases of OGIP.

JOE PARVAR
Senior Petroleum Engineer

Att

# YOLLA #1 RFT PRESSURE DATA

## RUN#1 (STRAIN GAUGE)

### 25 AUGUST 1985

| SEAT NO. | DEPTH (m kb) | HYDROSTATIC PRESSURE (psia) | FORMATION PRESSURE (psia) | REMARKS: |
|---|---|---|---|---|
| 1 | 1819.2 | 3023 | - | Tight |
| 2 | 1818.0 | 3024 | 2746 | Low flowing pressure |
| 3 | 1833.0 | 3052 | 2752 | Low flowing pressure |
| 4 | 1832.5 | 3054 | 2722 | Low flowing pressure |
| 5 | 1838.0 | 3064 | - | Seal Failure |
| 6 | 1839.0 | 3067 | 2731 | Low flowing pressure |
| 7 | 1843.0 | 3073 | 2739 | Low flowing pressure |
| 8 | 1846.5 | 3080 | 2742 | Low flowing pressure |
| 9 | 1856.0 | 3095 | 2753 | Low flowing pressure |
| 10 | 1868.0 | 3108 | 2763 | Low flowing pressure |
| 11 | 1905.0 | 3177 | 2836 | Low flowing pressure |
| 12 | 1921.0 | 3207 | 2850 | Low flowing pressure |
| 13 | 1946.0 | 3249 | 2888 | Low flowing pressure |
| 14 | 2034.0 | 3396 | 3019 | Low flowing pressure |
| 15 | 2125.0 | 3551 | 3160 | Low flowing pressure |
| 16 | 2215.0 | 3705 | 3299 | Low flowing pressure |
| 17 | 2327.0 | 3854 | 3415 | Very Low flowing pressure |
| 18 | 2428.0 | 4015 | 3556 | Very Low flowing pressure |
| 19 | 2636.0 | 4369 | - | Tight |
| 20 | 2637.0 | 4347 | - | Tight |
| 21 | 2639.5 | 4341 | - | Tight |
| 22 | 2642.5 | 4340 | - | Tight |
| 23 | 2720.0 | 4462 | - | Tight |
| 24 | 2722.5 | 4459 | - | Seal Failure |
| 25 | 2724.0 | 4458 | - | Tight |
| 26 | 2725.0 | 4458 | 4088 | Very Low flowing pressure |
| 27 | 2756.0 | 4513 | 4135 | Very Low flowing pressure |
| 28 | 2760.5 | 4506 | 4123 | Very Low flowing pressure |
| 29 | 2763.3 | 4507 | 4120 | Very Low flowing pressure |
| 31 | 2756.0 | 4518 | - | Seal Failure |
| 33 | 2811.0 | 4617 | 4168 | Low flowing pressure |
| 34 | 2813.0 | 4618 | 4162 | Low flowing pressure |
| 35 | 2819.0 | 4627 | - | Seal Failure |
| 36 | 2820.0 | 4623 | - | Seal Failure |
| 37 | 2821.0 | 4620 | - | Seal Failure |
| 38 | 2920.5 | 4617 | - | Seal Failure |
| 39 | 2823.5 | 4620 | - | Seal Failure |
| 40 | 2845.5 | 4651 | 4156 | Very Low flowing pressure |
| 41 | 2846.5 | 4648 | - | Seal Failure |
| 42 | 2874.0 | 4709 | - | Seal Failure |
| 43 | 2952.5 | 4865 | - | Seal Failure |

| SEAT NO. | DEPTH (m kb) | HYDROSTATIC PRESSURE (psia) | FORMATION PRESSURE (psia) | REMARKS: |
|---|---|---|---|---|
| 44 | 2720.0 | 4421 | - | Seal Failure |
| 45 | 2720.0 | 4465 | - | Seal Failure |
| 46 | 2722.5 | 4460 | - | Seal Failure |
| 47 | 2725.0 | 4462 | 4085 | Very Low flowing pressure |
| 48 | 2756.0 | 4519 | - | Seal Failure |
| 49 | 2760.5 | 4521 | 4114 | Very Low flowing pressure |
| 50 | 2763.3 | 4518 | 4123 | Very Low flowing pressure |
| 51 | 2811.0 | 4605 | 4152 | High flowing pressure |
| 52 | 2813.0 | 4598 | - | Seal Failure |
| 53 | 2815.0 | 4592 | - | Seal Failure |
| 54 | 2819.0 | 4591 | - | Seal Failure |
| 55 | 2820.0 | 4592 | 4122 | Low flowing pressure |
| 56 | 2821.0 | 4591 | 4146 | Low flowing pressure |
| 57 | 2823.5 | 4598 | 4144 | Low flowing pressure |
| 58 | 2845.5 | 4635 | 4129 | Low flowing pressure |
| 59 | 2874.0 | 4689 | - | Seal Failure |
| 61 | 2952.5 | 4855 | - | Seal Failure |
| 62 | 2952.8 | 4835 | - | Seal Failure |
| 63 | 2974.0 | 4870 | - | Seal Failure |
| 64 | 2973.8 | 4861 | - | Seal Failure |
| 65 | 2988.0 | 4889 | - | Seal Failure |
| 66 | 2989.0 | 4885 | - | Seal Failure |
| 67 | 2991.5 | 4884 | - | Seal Failure |
| 68 | 2821.0 | 4566 | - | Seal Failure |

# YOLLA #1 RFT PRESSURE DATA

## RUN#2 (HP GAUGE)

### 31 AUGUST 1985

| SEAT NO. | DEPTH (m kb) | HYDROSTATIC PRESSURE (psia) | FORMATION PRESSURE (psia) | REMARKS: |
|---|---|---|---|---|
| 1 | 1845.0 | 3238 | 2725.7 | Low flowing pressure |
| 2 | 1820.0 | 3095 | - | Tight |
| 4 | 1832.7 | 3116 | 2710.1 | V.High flowing pressure |
| 6 | 1807.0 | 3070 | - | Tight |
| 7 | 1814.0 | 3080 | - | Tight |
| 8 | 1820.0 | 3090 | - | Seal Failure |
| 9 | 1826.0 | 3102 | - | Seal Failure |
| 10 | 1830.0 | 3103 | 2712.0 | High flowing pressure |
| 11 | 1830.2 | 3108 | - | Seal Failure |
| 12 | 1832.0 | 3108 | - | Seal Failure |
| 13 | 1833.0 | 3111 | 2709.3 | V.High flowing pressure |
| 14 | 1837.0 | 3117 | 2712.8 | V.High flowing pressure |
| 15 | 1845.0 | 3130 | 2722.4 | V.High flowing pressure |
| 22 | 2724.0 | 4671 | 4126.0 | Low flowing pressure |
| 23 | 2762.0 | 4745 | - | Seal Failure |
| 24 | 2761.1 | 4735 | - | Seal Failure |
| 25 | 2761.3 | 4730 | 4156.0 | V.High flowing pressure |
| 26 | 2810.0 | 4823 | - | Seal Failure |
| 27 | 2811.0 | 4822 | - | Seal Failure |
| 28 | 2820.0 | 4832 | 4170.5 | V.High flowing pressure |
| 29 | 2874.0 | 4923 | 4238.0 | V.High flowing pressure |
| 30 | 2952.5 | 5060 | 4382.4 | V.High flowing pressure |
| 31 | 2974.0 | 5089 | - | Seal Failure |
| 32 | 2973.5 | 5084 | 4387.2 | High flowing pressure |
| 33 | 2988.0 | 5105 | 4387.3 | V.High flowing pressure |

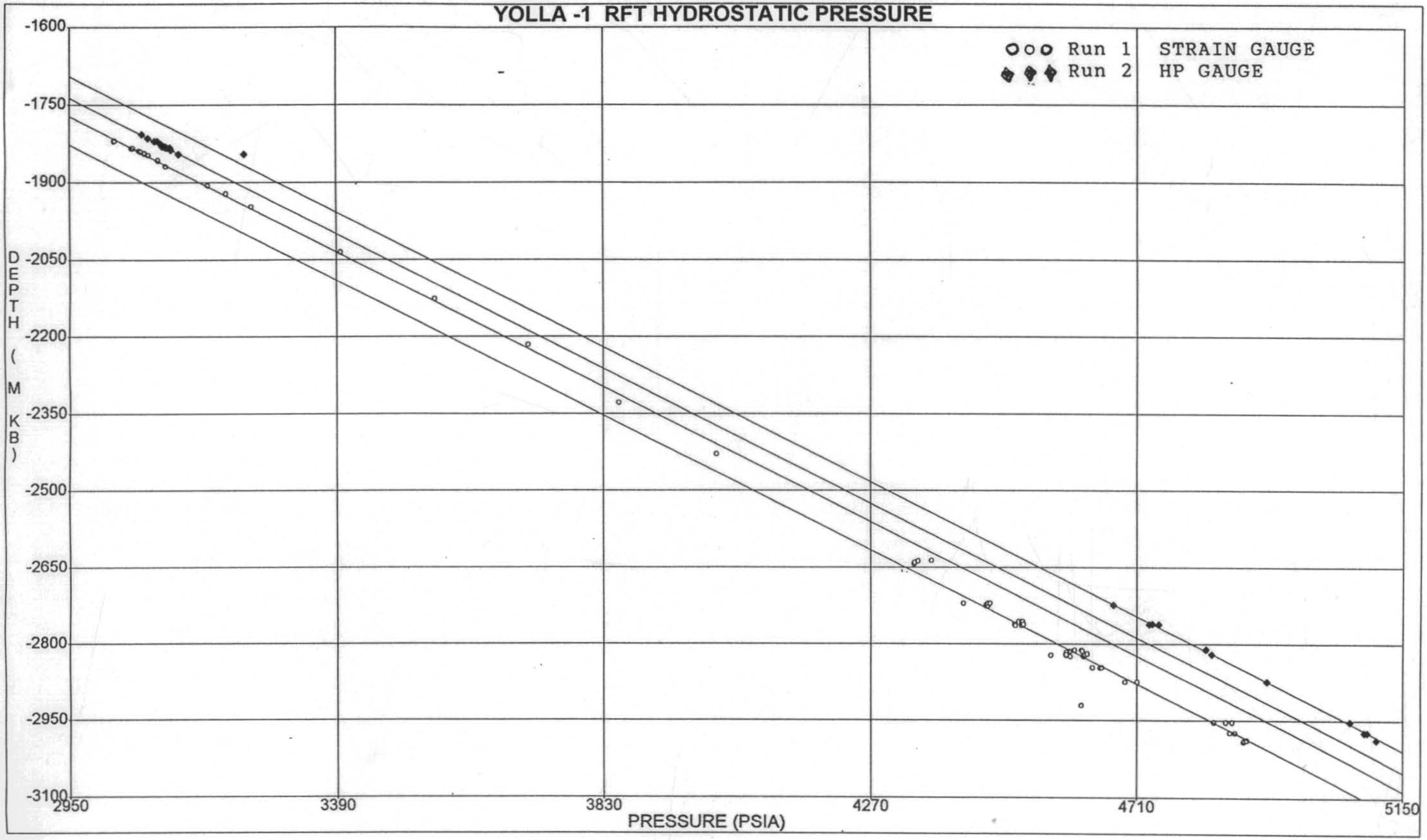

YOLLA -1 RFT HYDROSTATIC PRESSURE
Run 1 STRAIN GAUGE
Run 2 HP GAUGE
-1600
-1750
-1900
-2050
-2200
-2350
-2500
-2650
-2800
-2950
-3100
DEPTH (M KB)
2950
3390
3830
4270
4710
5150
PRESSURE (PSIA)

FIGURE 1

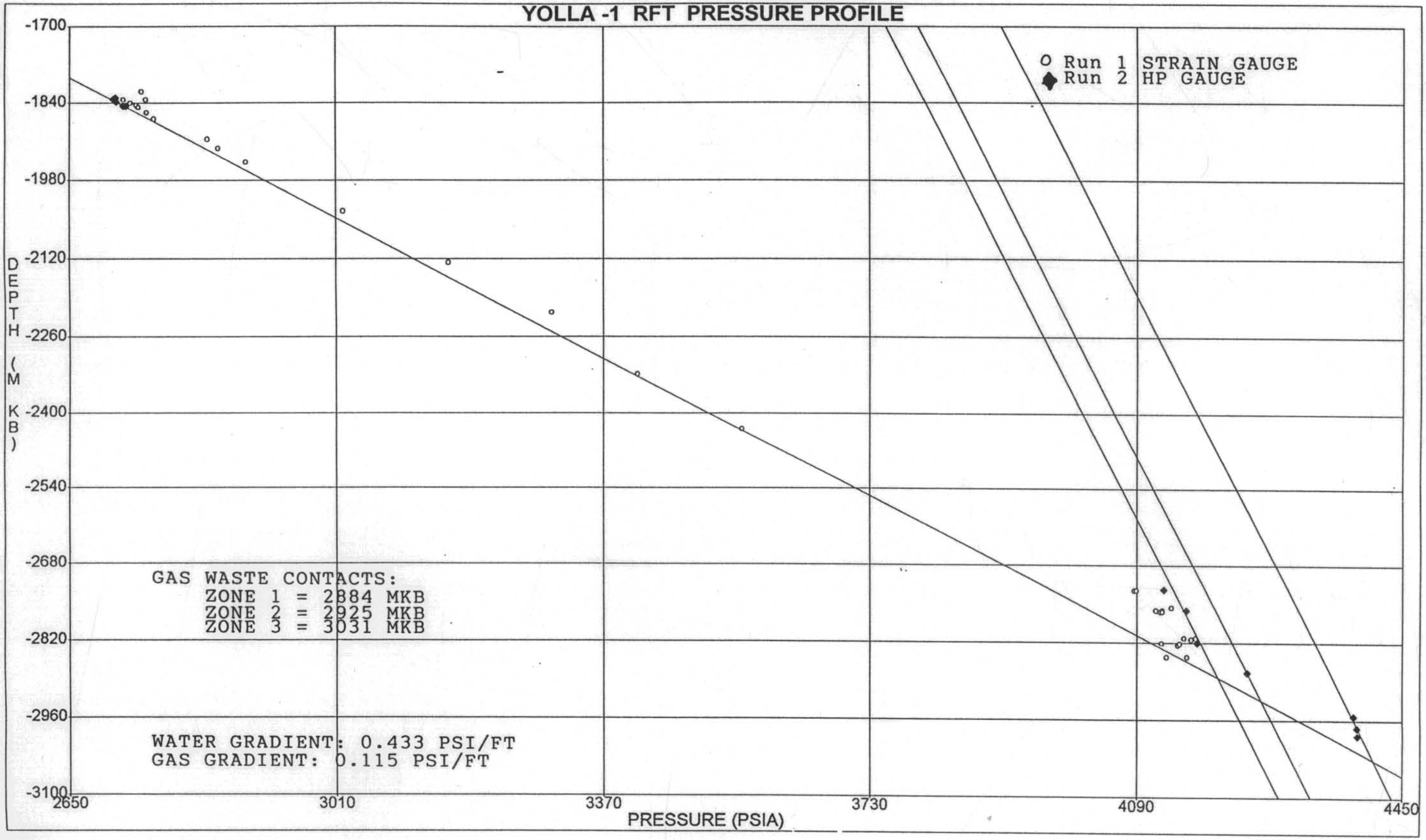

YOLLA -1 RFT PRESSURE PROFILE
Run 1 STRAIN GAUGE
Run 2 HP GAUGE
-1700
-1840
-1980
-2120
-2260
-2400
-2540
-2680
-2820
-2960
-3100
DEPTH (M KB)
2650
3010
3370
3730
4090
4450
PRESSURE (PSIA)
GAS WASTE CONTACTS:
ZONE 1 = 2884 MKB
ZONE 2 = 2925 MKB
ZONE 3 = 3031 MKB
WATER GRADIENT: 0.433 PSI/FT
GAS GRADIENT: 0.115 PSI/FT

FIGURE 2

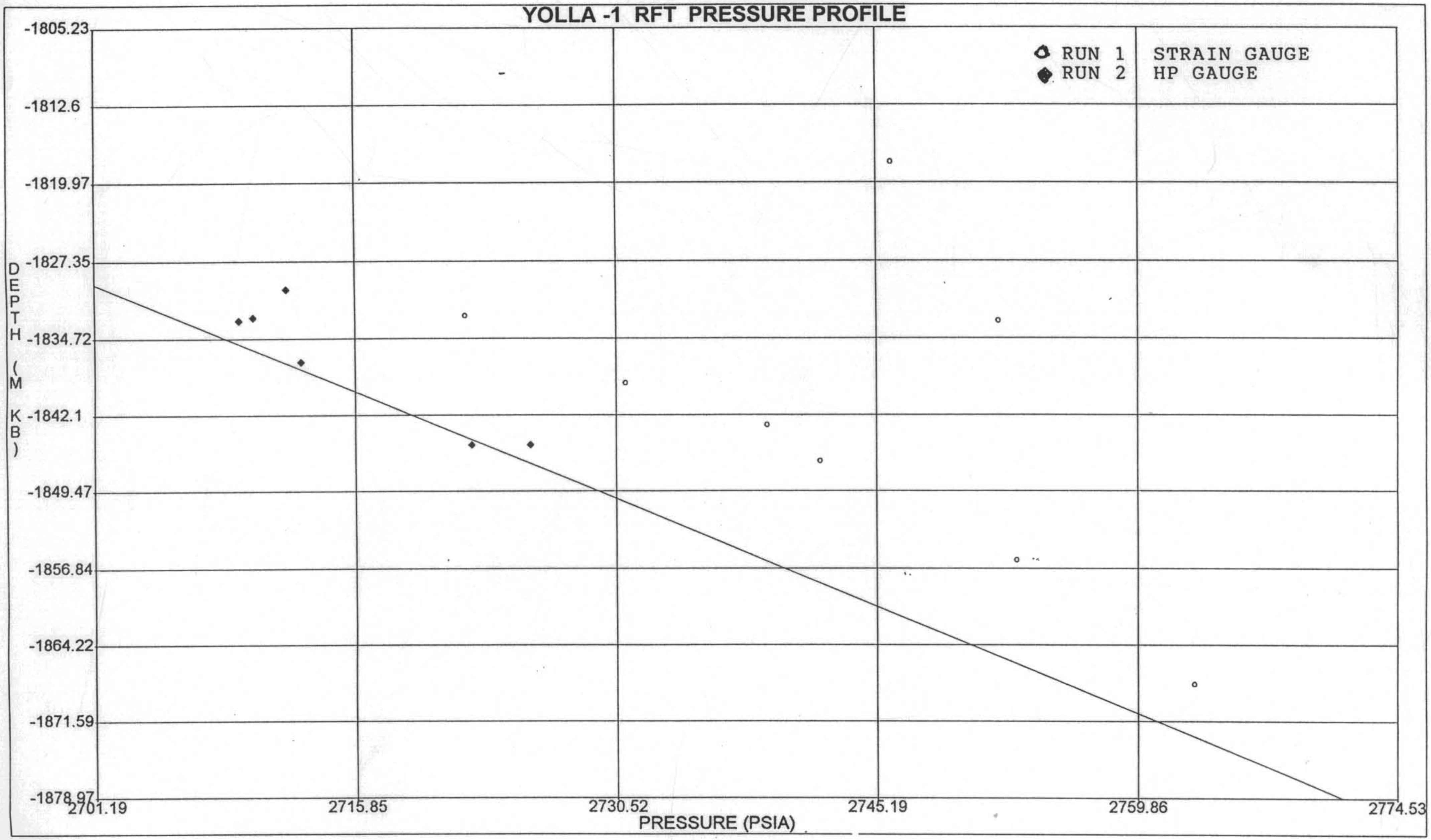

YOLLA -1 RFT PRESSURE PROFILE
RUN 1 STRAIN GAUGE
RUN 2 HP GAUGE
-1805.23
-1812.6
-1819.97
-1827.35
-1834.72
-1842.1
-1849.47
-1856.84
-1864.22
-1871.59
-1878.97
DEPTH (M KB)
2701.19
2715.85
2730.52
2745.19
2759.86
2774.53
PRESSURE (PSIA)

FIGURE 2A

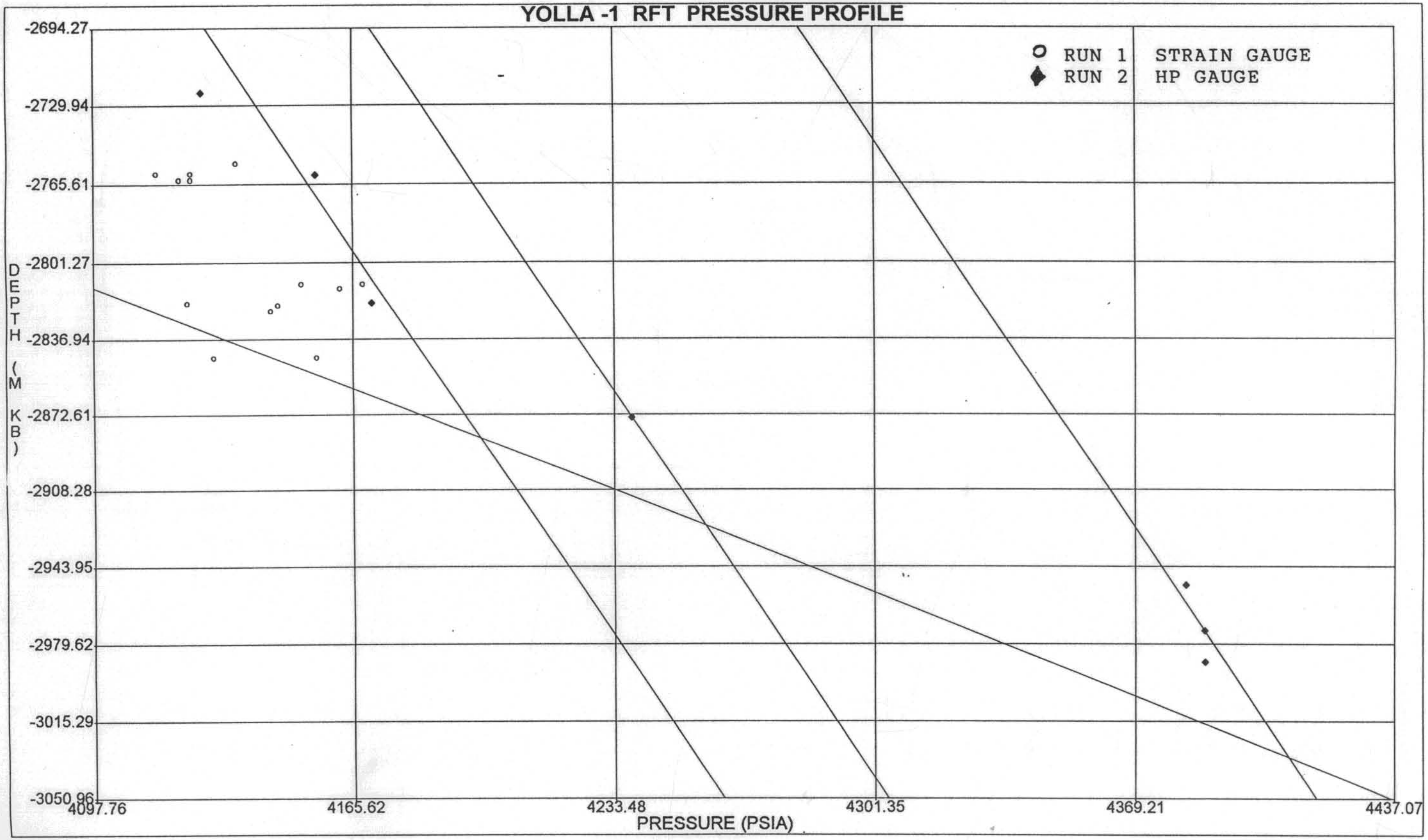

YOLLA -1 RFT PRESSURE PROFILE
RUN 1 STRAIN GAUGE
RUN 2 HP GAUGE
-2694.27
-2729.94
-2765.61
-2801.27
-2836.94
-2872.61
-2908.28
-2943.95
-2979.62
-3015.29
-3050.96
DEPTH (M KB)
4097.76
4165.62
4233.48
4301.35
4369.21
4437.07
PRESSURE (PSIA)

FIGURE 2B