AGL PETROLEUM
WEST MEREENIE 1 (P1)
MODIFIED ISOCRONAL TEST
(POST ACID TREATMENT)

DISTRIBUTION:
Magellan Petroleum 1
Santos Limited 1
AGL Petroleum - Darwin 1
Well File 1
Library 1

PREPARED BY:
Qld Operations 1
AGL Petroleum Limited 1
(ACN No. 009 666 700) 1
AGL House 1
60 Edward Street 1
DRISDANE QLD 4001

APRIL 1991
CONTENTS

SUMMARY 1
INTRODUCTION 2
ISO TEST ANALYSIS 3
BUILD-UP TEST ANALYSIS 5

APPENDICES

Figures

1 - Linear Plot of the Pressure History 7
2 - Well Deliverability c and n Analysis 8
3 - Well Deliverability LIT Analysis 9
4 - Diagnostic (Log-Log) Plot 10
5 - Horner (Semi-Log) Plot 11
6 - Type Curve Matching (Upper K and S) 12
7 - Type Curve Matching (Lower K and S) 13

Tables

1 - Results from Horner Analysis 14
2 - Results from Type Curve Match (Upper K and S) 15
3 - Results from Type Curve Match (Lower K and S) 16
Summary

Results from a four point modified isochronal test with extended flow and shut-in periods on West Mereenie 1 (P1) has revealed the following:

1. The formation is moderately permeable with a KH of 748 md-ft or greater.

2. There is a large skin, 50.6 or greater, associated with the well which indicates the formation is severely damaged around the wellbore. A small acid wash was run prior to this test. Although the well productivity was improved the acid was not sufficient to remove much of the wellbore skin, however the post acid KH was increased by a factor of two.

3. The identification of any dual porosity or two layer behaviour in the formation will be unlikely as the major portion of the pressure transient trend is masked by this severe formation damage.

4. A large quantity of condensate will drop out around the wellbore during the flow periods due to the significant pressure drop across the damaged zone. As a result, the analysis showed a negative slope in the LIT analysis, and an exponent of 1.359 in the c and n analysis.

5. The determination of the absolute open flow potential (AOF) of the well is inconclusive due to the flow restriction caused by the severe formation damage. The minimum AOF from the well is found to be 4.0 MMscfd from the c and n analysis.

6. A decrease in the pressure derivatives at the end of the build-up test may indicate the existence of a no-flow boundary.

7. A conclusive estimate for the well’s production potential and reservoir properties cannot be obtained until the formation damage is remedied.
Introduction

West Mereenie 1 was originally a gas producer with a barefoot completion over the P1 and P3 intervals. A workover was performed in February 1991 to segregate the P1 and P3 sands with a dual string completion.

During the workover, approximately 1800 barrels of completion fluids loaded with 30 lb/bbl calcium carbonate was lost to the formation. After the workover the well was swabbed on and approximately 400 barrels of fluid was recovered.

A 12 hour pressure build-up survey was conducted over the P1 interval after the clean-up operation to identify the extent of the formation damage. Qualitatively the test showed that the kH of the well was approximately 370 md-ft with a skin factor of 55.

A small acid wash treatment was conducted on this well on 22 March 1991, in an attempt to remove some of the wellbore damage caused by the calcium carbonate completion fluid.

A modified Isochronal test (ISO) with extended flow and shut-in periods has been conducted on WM 1 (P1) between 1 April and 7 April 1991. The aim of the test was to evaluate the well's production potential and reservoir properties after the acid treatment. A linear plot of the pressure history during the ISO and build-tests is shown in Figure 1.
**ISO Test Analysis**

The results of the ISO test with the extended flow period are listed as follows:

<table>
<thead>
<tr>
<th>BHFP (psia)</th>
<th>GAS RATE (MMscfd)</th>
<th>DURATION (hrs)</th>
<th>TYPE</th>
</tr>
</thead>
<tbody>
<tr>
<td>1263.0</td>
<td>1.436</td>
<td>3</td>
<td>Flowing</td>
</tr>
<tr>
<td>1734.0</td>
<td>0</td>
<td>3</td>
<td>Shut-in</td>
</tr>
<tr>
<td>1063.6</td>
<td>2.184</td>
<td>3</td>
<td>Flowing</td>
</tr>
<tr>
<td>1731.5</td>
<td>0</td>
<td>3</td>
<td>Shut-in</td>
</tr>
<tr>
<td>886.9</td>
<td>2.608</td>
<td>3</td>
<td>Flowing</td>
</tr>
<tr>
<td>1731.3</td>
<td>0</td>
<td>3</td>
<td>Shut-in</td>
</tr>
<tr>
<td>810.5</td>
<td>2.820</td>
<td>3</td>
<td>Flowing</td>
</tr>
<tr>
<td>1014.6</td>
<td>2.382</td>
<td>36</td>
<td>Extended</td>
</tr>
</tbody>
</table>

The flow equations under consideration for analysis are:

* c and n Analysis :  \( Q = c \left( P_i^2 - P_{wf}^2 \right)^n \)

* LIT Analysis :  \( \left( P_i^2 - P_{wf}^2 \right)/Q = B + PQ \)

where \( P_i \) is the static reservoir pressure and \( P_{wf} \) is the bottomhole flowing pressure.
The results of the analyses are shown in Figures 2 & 3 and summarised as follows:

### c and n Analysis

<table>
<thead>
<tr>
<th>c</th>
<th>n</th>
<th>AOF (MMscfd)</th>
</tr>
</thead>
<tbody>
<tr>
<td>6.330 E-09</td>
<td>1.359</td>
<td>4.0</td>
</tr>
</tbody>
</table>

### LIT Analysis

<table>
<thead>
<tr>
<th>B</th>
<th>F</th>
<th>AOF (MMscfd)</th>
</tr>
</thead>
<tbody>
<tr>
<td>88708.3</td>
<td>-8.967</td>
<td>2.4</td>
</tr>
</tbody>
</table>

From the c and n analysis, the exponent (n) is found to be 1.359. Usually n will be between 0.5 and 1.0. In the LIT analysis, the slope of \( d(p^2)/Q \) vs Q is negative. Physically the slope (F) is a measure of pressure decrease due to inertial-turbulent flow effects and will be positive.

The reason for such abnormality in the test is very likely due to the condensate build-up around the wellbore. The cause of the condensate build-up is due to a significant pressure drop across the damaged zone. The damaged zone is found to have a skin factor of 50.6 or greater from the pressure build-up analysis in the next section.

Therefore, the result of the flow test cannot be used to forecast the future deliverability of the well. The AOF of the well will be 4.0 MMscfd at minimum. It is noted in Figure 1 that the pressure reading during the extended flow period has been slightly increased. This may indicate the well is cleaning itself up. However the extent of the clean-up by production will be limited since the formation damage is too severe.
Build-up Test Analysis

The well was shut in for a 71 hour pressure build-up survey after the extended flow test. The log-log plot of dp vs dt (diagnostic plot) is shown in Figure 4.

As observed from the diagnostic plot, the Middle Time Region (MTR) appears to start and end between 10 and 25 hours of shut-in time, as indicated by the flattened pressure derivatives. The decrease of the pressure derivatives after 30 hours of shut-in time to the end of the test may indicate the existence of a no-flow boundary.

The result of Horner analysis is shown in Figure 5 and Table 1. The Horner straight line is drawn based on the abovementioned MTR pressure data.

The application of the type curve match is not unique in this test. The match using the upper limits of permeability and skin is shown in Figure 6 and Table 2. Figure 7 and Table 3 are obtained using the lower limits of permeability and skin. It is noteworthy to point out that the effect of a square boundary with the well at its centre has been incorporated into the type curve matching as shown in Figures 6 and 7.

The result of the build-up analysis is listed as follows:

<table>
<thead>
<tr>
<th></th>
<th>KII (md-ft)</th>
<th>S</th>
<th>P*  (psia)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Horner</td>
<td>748.2</td>
<td>50.6</td>
<td>1738.8</td>
</tr>
<tr>
<td>Gringarten (Upper)</td>
<td>1082.0</td>
<td>77.3</td>
<td></td>
</tr>
<tr>
<td>Gringarten (Lower)</td>
<td>858.9</td>
<td>56.6</td>
<td></td>
</tr>
</tbody>
</table>

The results from Horner method and type curve matching are reasonable and indicates that the formation is moderately permeable with a KII of 748 md-ft or greater and the formation is severely damaged with a skin factor of 50.6 or greater.
The acid treatment prior to the test was able to improve the well’s performance to some extent. Under a 24/64 inch choke, the gas flow rate prior to the treatment was 1.5 MMscfd with a bottomhole flowing pressure (BHFP) of 767 psia, comparing with a rate of 2.4 MMscfd and a BHFP of 1015 psia after the treatment and the extended flow. Although the well’s productivity was improved the acid treatment was not sufficient to remove much of the wellbore skin. The post acid KH appears to be increased by a factor of two.

A deliverability calculation using the Horner extrapolated pressure and any pair of above KH and S will yield a AOF of 3.7 MMscfd. This calculation is comparable with the results from the ISO flow test and confirms a high skin factor is present in the well.

Efforts have been made on the type curve matching using dual porosity type curve. However a typical hump in pressure derivatives was not observe and the shape of the dual porosity type curve is identical with that from Gringarten type curve. The effect of the abnormally high skin factor associated with the well is to mask the effect of the dual porosity (or two layer system) behaviour as shown in the results of WM 1 (P3) pressure build-up test.

Confirmation of the reservoir properties, i.e. dual porosity/two layer system or no-low boundary, cannot be made until the formation damage is remedied and the well is re-tested.
File: #MUTSO1.GAS
Analyst name: C. S. CHEN
Company: AGL PETROLEUM
Well: WM 1 (P1)

Field: MEREENIE
Date: 01-04 TO 07-04 91
Rig Name/Number:
Test: MUD ISO WITH EXTENDED FLOW AND BU

PANSYSYTEM V1.7 (C) EPDS 1990.

WM 1 (P1) - PRESSURE v TIME

Pressure (psia)

1800.000
1625.000
1450.000
1275.000
1100.000
925.000
750.000

0.0000 13.000 26.000 39.000 52.000 65.000 78.000 91.000 104.000 117.000 130.000

Time (hours)

Figure 1
WM 1 (P1) - SANDFACE DELIVERABILITY

Field: MEERENIE
Date: 01-04 TO 07-04 91
Rig Name/Number: MOD ISO WITH EXTENDED FLOW AND BU

AOF: 4.040
C: 6.33E-09
n: 1.359

Figure 2

Gas flow rate (MMscf/day)
File: WM1US01.GAS
Analyst name: C. S. CHEN
Company: AGP PETROLEUM
Well: WM 1 (P1)

Field: HERBEENIE
Date: 01-04 TO 07-04 91
Rig Name/Number: AOF
Test: MOD ISO WITH EXTENDED FLOW AND BU

Figure 3

Gas flow rate - MMscf/day

psi2 (x1E+06)/MMscf/day

d(P**2)/Q

1.100
1.050
1.000
0.9500
0.9000
0.8500
0.8000

1.200
1.400
1.600
1.800
2.000
2.200
2.400
2.600
2.800
3.000
3.200
Field: MEREENIE  Slope: 0.0000
Date: 04-04 TO 07-04 91  Intercept: 0.0000
Rig Name/Number:
Test: BUILD-UP TEST AFTER EXTENDED FLOW
Field: MEREENIE
Date: 04-04 TO 07-04 91
Rig Name/Number: BUILD-UP TEST AFTER EXTENDED FLOW
Test: WM 1 (P1)

Slope: -0.0389
Intercept: 3.023
Permeability: 46.762
Skin: 50.563
Figure 6

WM 1 (P1) - HOMOGENEOUS RESERVOIR

File: WM1AP94.GAS
Analyst name: C. S. CHEN
Company: ASL PETROLEUM
Well: WM 1 (P1)

Field: MEREDIE
Date: 04-04 TO 07-04 91
Rig Name/Number:
Test: BUILD-UP TEST AFTER EXTENDED FLOW

Pd (match): 421.696 dp (match): 10.000
Td (match): 184.483 dt (match): 1.000
Permeability: 67.815 dp (skin): 562.792
Skin: 75.241 C_storage: 0.1820

Data plotted using Real Elapsed Time and P*2

\[
C = 2.60 \times 10^{18.8}
\]

DIMENSIONLESS PRESSURE \( P_d = \frac{khTsc}{5030qTPsc} \) (P)

DIMENSIONLESS TIME \( (Td/Cd) = 0.000295 \) (khdt/\( uC \))
WM 1 (P1) - HOMOGENEOUS RESERVOIR

Field: MEREENIE
Analyst name: C. S. CHEN
Company: AGL PETROLEUM
Well: WM 1 (P1)

Pd (match): 339.821  dp (match): 10.000
Td (match): 159.268  dt (match): 1.000
Permeability: 53.682  dp (skin): 626.644
Skin: 55.556  C (Storage): 0.1669

Dimensionless Pressure $P_d = \frac{kh_{isc}}{50300kipscf (P)}$

Dimensionless Time $(T_d/C_d) = 0.000295$ (khdt/uc)
RESULTS FROM HORNER ANALYSIS
using Pressure-squared and Pressure-squared

Line :

Intercept: 3.023
Slope: -0.0389
Start of line: (0.0000, 0.0000)
End of line: (0.0000, 0.0000)
Coefficient of determination: 0.0000
Number of points: 0

p**2 at dt = 1 hr: 2.9608 psi2 (*1E-06)
Extrapolated p**2: 3.0235 psi2 (*1E-06)
Permeability-thickness (kh): 748.1965 md.ft
Permeability (k): 46.7623 md
Total skin factor (s): 50.5634
dp skin (constant rate): 639.9492 psi
Radius of investigation: 2058.8103 ft
Extrapolated pressure: 1738.8149 psia
Pressure at dt = 1 hour: 1720.6834 psia
Flow efficiency: 0.1434
RESULTS FROM A HOMOGENEOUS RESERVOIR TYPE-CURVE MATCH
(WELLBORE STORAGE ANALYSIS)

Data plotted using Real Elapsed Time and P**2

Dim. pressure match point $P_d(\text{match})$........: 421.6965
Dim. time match point $T_d/C_d(\text{match})$........: 184.4834
Matched curve Cde2S(\text{match}) ..................: $4.432 \times 10^{-68}$
Pressure match point $dP(\text{match})$ ............: 10.0000
Time match point $dt(\text{match})$ ..................: 1.0000
Permeability-thickness (kh) .......................: 1085.0423 md.ft
Permeability (k) .................................: 67.8152 md
Apparent wellbore volume .........................: 280.5069 bbl
Wellbore storage coefficient (C) ..................: 1964.1840 bbl/psi
Storage coefficient (initial) ......................: 0.1820 bbl/psi
Radius of investigation ...........................: 2479.3156 ft
$dP$ skin (constant rate) .........................: 662.7920 psi
Skin factor (S) .................................: 75.2409
Rate dependent skin coefficient (D) .............: 0.0000 1/(Mscf/day)
Characteristic length (L) .......................: 4000.0000 ft
Boundary type ...................................: 4SQ [L:L:L:L]

Table 2
E.P.S. Ltd.  

PANSYSTEM ANALYSIS PROGRAM

File: WMIUAP91.GAS  

Date: 10/04/91  

Test type: CRB

RESULTS FROM A HOMOGENEOUS RESERVOIR TYPE-CURVE MATCH  
(WELLBORE STORAGE ANALYSIS)

Data plotted using Real Elapsed Time and P**2

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dim. pressure match point Pd(match)......</td>
<td>339.8208</td>
</tr>
<tr>
<td>Dim. time match point Td/Cd(match).......</td>
<td>159.2677</td>
</tr>
<tr>
<td>Matched curve Cde2S(match)...............</td>
<td>2.394E+52</td>
</tr>
<tr>
<td>Pressure match point dP(match)...........</td>
<td>10.0000</td>
</tr>
<tr>
<td>Time match point dt(match)...............</td>
<td>1.0000</td>
</tr>
<tr>
<td>Permeability-thickness (kh)...............</td>
<td>858.9171 md.ft</td>
</tr>
<tr>
<td>Permeability (k).......................</td>
<td>53.6823 md</td>
</tr>
<tr>
<td>Apparent wellbore volume................</td>
<td>257.2041 bbl</td>
</tr>
<tr>
<td>Dim. wellbore storage constant (Cd)......</td>
<td>1801.0111</td>
</tr>
<tr>
<td>Storage coefficient (initial)...........</td>
<td>0.1669 bbl/psi</td>
</tr>
<tr>
<td>Radius of investigation..................</td>
<td>2205.8913 ft</td>
</tr>
<tr>
<td>dP skin (constant rate)..................</td>
<td>626.6438 psi</td>
</tr>
<tr>
<td>Skin factor (S)..........................</td>
<td>56.5557</td>
</tr>
<tr>
<td>Rate dependent skin coefficient (D)......</td>
<td>0.0000 1/(Mscf/day)</td>
</tr>
<tr>
<td>Characteristic length (L)................</td>
<td>4250.0000 ft</td>
</tr>
<tr>
<td>Boundary type................................</td>
<td>48Q [L:L:L:L]</td>
</tr>
</tbody>
</table>

Table 3