An Alternative Method of Calculating Cushion Gas and Non-Recoverable Gas

Manlove Mt. Simon Reservoir

Prepared for
The Peoples Gas Light and Coke Company

December 1998

Prepared by
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December 18, 1998

Mr. R. deLara
Mr. T. Koller
The Peoples Gas Light and Coke Company
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Fisher, IL 61843

Gentlemen:

At your request, Smedvig made a review of the procedures used to calculate "Top Gas", "Non-Recoverable Gas" and "Cushion Gas" for the Manlove Field. Based on the review, a new calculation procedure has been developed. The following report discusses the new procedure, and presents results of the new calculations.

Smedvig appreciates the opportunity to perform this service for Peoples.

Sincerely,

Charles R. Connaughton

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Project Manager

CRC:dlh

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Executive Summary

Peoples Gas asked Smedvig to review the methods used to calculate "Top Gas", "Non-Recoverable Gas", and "Cushion Gas" for the gas storage operation in the Manlove Field. Categories are defined in Table 1 and shown on Fig. 1. Based on that review, a new calculation procedure has been developed.

The new procedure is based on a petroleum industry calculation technique known as the Stiles' calculation. The calculation uses the field permeability distribution and the reservoir mobilities of gas and water. The calculation yields values of water gas ratio (WGR) as a function of fractional recovery.

The new procedure relates the measured field WGR and fractional recovery at the end of a withdrawal season to the Stiles' results, and then uses the Stiles' calculation to predict fractional recoveries when certain limiting WGR's are reached.

10.5 gal/mcf

The limiting WGR for "Top Gas" is 250 Bbl/MMscf, based on the water handling capacity of the plant under normal operating conditions. The limiting WGR for "Total Recoverable Gas" is 600 (25.2 gal/mcf) Bbl/MMscf, the conditions under which wells cease to flow or gas rates become very low.

The following table summarizes the results at the end of the 1997-1998 withdrawal season: (all values in Bscf)

A.	Starting Inventory	147.521
B.	Seasonal Withdrawal	26.850
C.	Total Top Gas – (Stiles')	32.160
D.	Total Cushion Gas – (A – C)	115.361
E.	Total Recoverable Gas – (Stiles')	36.219
F.	Recoverable Cushion Gas – (E – C)	4.060
G.	Non-Recoverable Gas – (A – E)	111.302

Details of the calculation are shown on Table 3 for the last 8 injection – withdrawal cycles.

The "Non-Recoverable Gas" is increased in the new procedure compared with the old procedure. Smedvig strongly feels that this is consistent with observed field performance, and that the new technique is better suited to the present state of the field.

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1.0 INTRODUCTION

It is necessary to determine annual volumes of cushion gas and non-recoverable gas annually for accounting purposes. There is no precise way to calculate these values for the complex Manlove Mt. Simon gas storage reservoir.

The method that has been used in the past to calculate these values is cumbersome, and several points in the calculation procedure require subjective judgements. Peoples Gas asked Smedvig to investigate alternative methods for the calculation.

An alternative calculation procedure has been developed. The heart of this calculation is a Stiles' waterflood calculation[1]. This calculation uses the permeability variation in the field to derive a relationship between the produced water-gas ratio and fractional recovery.

Besides being based on a calculation procedure recognized in the industry, this new method incorporates water-gas ratios at the end of the season to calculate "Top Gas" and "Total Recoverable Gas". As a result, it should more accurately account for variations in field operations than the previous method. Variations in withdrawal patterns and rates greatly affect the state of the Mt. Simon reservoir at the end of the withdrawal season.

2.0 THE METHOD

2.1 Basic Considerations

The calculation procedure is based on the premise that if the Manlove field were abandoned, it would be done by withdrawing as much gas as possible after a withdrawal season.

The Mt. Simon formation at Manlove is an infinite-acting aquifer. The original pressure was about 1750 psi. At the end of a withdrawal season, the pressure in the immediate field is less than this. If injection were not started for the next seasonal cycle, water would move into the storage volume until the initial pressure was reached.

This encroaching water would cause the ultimate abandonment of the field. The water traps gas and the gas becomes immobile. As the water reaches wells, it restricts gas productivity and loads the well with water, killing them. As a result, very high fractions of the gas in place will be non-producible.

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[1] Stiles', W.E., "Use of Permeability Distribution in Water-Flood Calculations, " Trans. AIME (1949), v. 186, pp. 9-13.

Unlike gas storage in depleted oil or gas reservoirs, storage in aquifers is inherently inefficient. Abandonment of storage in a depleted oil or gas reservoir occurs when the reservoir pressure declines to a level that no longer will support economic production. It is a relatively simple matter to calculate the remaining gas in place at a specific pressure. The recovery fraction is essentially proportional to the amount the reservoir pressure declines from starting pressure to abandonment pressure.

Abandonment at Manlove would occur when produced water levels either kill wells directly, or reduce the gas-producing rate to less than economic levels. In most wells, both events will occur very near to the same time. When water invades a well late in the season, water-gas ratios rise rapidly, gas production declines rapidly, and the well dies.

Peoples gas has determined from past operational experience that wells will die, or become uneconomic, when water gas ratios (WGR's) reach 600 barrels per million standard cubic foot (Bbls/MMscf). Based on many years of monitoring Manlove operations, Smedvig agrees that this is a reasonable operational limit, although probably on the high side for all but the very best wells. Examination of five years of performance plots shows that when a well begins to water out, the WGR rises very rapidly and the gas rate drops very rapidly. Accordingly, "Total Recoverable Gas" is based on the recovery factor when the limiting water gas ratio of 600 Bbls/MMscf is reached.

Since water invasion will determine abandonment conditions at Manlove, the present calculation incorporates a procedure that accounts for reservoir heterogeneities and relates water production to recovery on that basis.

2.2 Definitions of Inventory Classifications

Terms such as "Top Gas" and "Cushion Gas" do not have standard definitions in the gas storage industry. For this study, definitions have been adopted that correspond as closely as possible to those required for accounting purposes, as presented in Table 1.

The definitions in the table are more easily followed by referring to Fig. 1, an illustration of the distribution of inventory at Manlove. There are four basic classifications, and two derived classifications.

The "Seasonal Withdrawal" is the gas withdrawn operating under normal deliverability pressures. Normally, some additional gas could be recovered at the end of a withdrawal season using the same operating conditions. That gas is the "Additional Recoverable in Normal Operations."

All of the gas that could be withdrawn under normal operating conditions is "Top Gas". The gas required to supply the pressure necessary to deliver the "Top Gas" is the "Cushion Gas".

The "Top Gas" recovery factor is based on a limiting WGR ratio under normal operations of 250 Bbls/MMscf. This value is based on a plant water handling capacity of 50,000 Bbl/D, and an end of season throughput of 200,000 Mscf/D.

If abandonment were to occur, some additional gas could be recovered by lowering wellhead pressures and by other changes in operations. That gas is "Blowdown Recoverable" gas. Finally, there is a "Non-Recoverable" gas volume.

2.3 The Stiles' Calculation

As mentioned previously, the Stiles' water-flood technique is the basis of the procedure. That calculation, and other correlations used in the calculation are discussed in the following paragraphs.

The Stiles' calculation assumes that, for water displacing gas, the rate of water advance in a linear bed is proportional to the permeability of the bed. In addition, the method assumes that rate of fluid movement is proportional to gas mobility if water breakthrough has not occurred, or to water mobility if breakthrough has occurred.

All core data above net cut-offs of 6 percent porosity and 0.1 md permeability were used in the calculation, a total of 3578 samples. These cut-offs are based primarily on observations from EPILOG surveys. EPILOG surveys are down-hole logs that indicate gas saturation. Virtually no gas saturation is found in rock with less than 6 percent porosity. The data were ordered into 14 groups based on permeability, as shown on Table 2.

The calculation requires a water gas mobility ratio, M_{WG}.

$$M_{WG} = \frac{k_{rw}\, \mu_g}{k_{rg}\, \mu_w}$$

where,

k_r = relative permeability to a fluid phase
μ = viscosity of the phase

An M value of 0.052 was used based on laboratory tests on cores from the J. Williams 4 well, Table 3.

An average trapped gas saturation is also required in the calculation. Based on previous work, a value of 0.56 was used. Core tests on 12 samples from the J. Williams 4 showed an average trapped gas saturation of 0.61, so the value used may be slightly conservative.

Results of the Stiles' calculation are shown in Table 2 and on Fig. 2. The calculation assumes 100 percent conformance (sweep efficiency). Figure 2 also shows the recovery/water-gas ratio relationship for other conformance values. These curves are used in the calculation of recoverable gas, as explained in Section 3.2 of this report.

3.0 CALCULATION OF CUSHION GAS AND NON-RECOVERABLE GAS

The procedure developed to calculate Cushion Gas and Non-Recoverable Gas is based on the correlations and principles previously discussed. The results are presented in Table 4.

Table 4 has five parts as shown by the major heading at the top:

Seasonal Data
Stiles' Recovery Factors
Top Gas and Total Cushion Gas
Recoverable and Non-Recoverable Gas
Recoverable Cushion Gas

Each part is discussed in the following sections.

3.1 Seasonal Data

This section merely reports the starting and ending date for each withdrawal or injection season and the starting inventory. The end of season WGR's, [h], are picked from seasonal plots of instantaneous WGR versus cumulative WGR. These plots are shown on Figs. 3 – 10. The point chosen is usually the highest reached during normal operations at the end of a season.

3.2 Stiles' Recovery Factor

In a gas storage operation in a strong aquifer, such as the Manlove Field Mt. Simon reservoir, a high proportion of the gas will be left in the ground. Laboratory tests on Mt. Simon cores show average trapped gas saturations of 61 percent. This gas will be trapped at a high pressure, because, as withdrawals are lessened, the aquifer will return the reservoir to original pressure.

In addition, the heterogeneous nature of the Mt. Simon reservoir will result in movable gas being bypassed; that is, the conforming volume will be some fraction of the total volume.

This conforming volume at the end of a withdrawal season varies from season to season. It depends on, among many other factors, the injection pattern and injected volume distribution during the injection season. Is also depends on the same factors during the withdrawal season.

There is evidence that the recovery in a given withdrawal season may be influenced by these factors from several previous seasons.

The "Top Gas Recovery Factor" and the "Total Recovery Factor" are functions of the conformance at the end of normal withdrawal operations. For a given conformance factor and limiting WGR, a recovery factor can be taken from the Stiles' relationships shown on Fig. 2. As discussed previously, the limiting WGR for "Top Gas" is 250 Bbl/MMscf, and that for "Total Recoverable Gas" is 600 Bbl/MMscf.

The starting point for determining the "Top Gas Recovery Factor" and the "Total Recovery Factor" is the end of season water-gas ratio and the seasonal percent recovery, columns [h] and [i], Table 4. These are plotted on Fig. 11, an expanded version of Fig. 2, to determine the conformance factor for the season. The recovery factor can then be read from the graph at the intersection of the conformance line with the 250 and 600 Bbl/MMscf water-gas ratio limits from the graph.

As an example, the 1990 – 91 end-of-season values for WGR and fractional recovery are 135 Bbl/MMscf and 22.4 percent recovery, represented by the open square on the figure at about 75 percent conformance. The eighty-five percent conformance line (shown dashed for illustration) intersects the 250 Bbl/MMscf "Top Gas" limit at 26.4 percent, and the 600 Bbl/MMscf "Total Recovery" limit at a recovery value of about 29.7 percent.

A more quantitative way was found to determine the values from the graph. Once the conformance is established by plotting the WGR and fractional recovery at the end of the season, the recovery factors can be determined from the simple relationships:

Fractional Recovery (@250 Bbl/MMscf) = (0.350 x Conformance) + 0.001
Fractional Recovery (@ 600 Bbl/MMscf) = 0.396 x Conformance

Hence, the recovery factors for the 1990 – 91 conformance of 0.75 are:

Recovery Factor (@250 Bbl/MMscf) = (0.350 x 0.75 + 0.001) = 0.264
Recovery Factor (@ 600 Bbl/MMscf) = 0.396 x 0.75 = 0.297

3.3 Top Gas and Total Cushion Gas

The "Top Gas" [m] is the product of the "Top Gas Recovery Factor" [k] and the starting inventory [e]. This is the total gas that could be recovered under normal operations until the limiting WGR of 250 Bbl/MMscf was reached.

The "Total Cushion Gas" [n] is then, by definition, the starting inventory [n] less the "Top Gas" [m] (See Fig. 1).

3.4 Recoverable and Non-Recoverable Gas

The "Total Recoverable Gas" [o] is the total gas that could be recovered by changes in operating methods such as lowering well-head pressure or increasing plant liquid handling capacity. The "Total Recoverable Gas" [o] is the product of the "Total Recovery Factor" [l] and the starting inventory [e].

The "Non-Recoverable Gas" [p] is then the starting inventory [e] minus the "Total Recoverable Gas" [o].

3.5 Recoverable Cushion Gas

Some of the Cushion Gas could be recoverable under field blowdown conditions. Reference to Fig. 1 again is helpful. The recoverable Cushion Gas [q] is the Total Cushion Gas [n] minus the non-recoverable gas [p].

4.0 FINAL COMMENTS

As stated in the introduction, there is no precise way to calculate cushion gas and non-recoverable gas volumes at Manlove. However, this new calculation procedure yields what are thought to be better representative values than previous methods. It is based on a recognized method of calculating the WGR-recovery relationship. It also takes into account the actual state of the field at the end of each withdrawal season, and relates that to the above relationship.

Recent developments in the gas industry have suggested that changes in the Manlove cycle of operations might be necessary because of demand factors; that is, an operating year might not consist of one injection season and one withdrawal season. If such changes occur, this calculation procedure will have to be re-evaluated. However, under the present operating system, this method should provide a realistic and consistent manner of calculating the required volumes.

LIST OF TABLES

TABLE 1

Definitions of Inventory Classifications

"Seasonal Withdrawal"	The gas withdrawn during an operating season under normal operating pressures. The volume varies according to customer needs and deliverability capabilities.
"Additional Recoverable in Normal Operations"	Gas that could be withdrawn under normal operating pressures after the end of a withdrawal season.
"Blowdown Recoverable"	Gas that could be recovered economically operating under reduced surface pressures.
"Non-Recoverable"	Gas that is not economically recoverable.
"Top Gas"	The total gas that could be withdrawn under normal operating pressures. "Top Gas" is the sum of "Season Withdrawal" and "Additional Recoverable in Normal Operations".
"Cushion Gas"	The minimum volume of gas necessary to provide the pressure required to deliver gas under normal operations. "Cushion Gas" is "Non-Recoverable" gas plus "Blowdown Recoverable", or "Seasonal Withdrawal" plus "Additional Recoverable in Normal Operations", the "Top Gas".

SUMMARY OF STILES DATA AND RESULTS

MANLOVE FIELD

GROUP TAG	Min K-air (Horiz)	COUNT FROM	COUNT TO	PERMEABILITY RANGE FROM	PERMEABILITY RANGE TO	RECOV. PERCENT TOTAL GIP	SURFACE WATER-GAS RATIO BBL/MMcf
1	724	1	5	724	1072	1.7	3
2	622	6	10	622	724	2.9	5
3	505	11	18	505	622	4.7	8
4	402	19	29	402	505	6.5	11
5	251	30	56	251	402	9.8	19
6	200	57	86	200	251	12.5	26
7	150	87	157	150	200	17.0	41
8	100	158	278	100	150	22.7	69
9	75	279	402	75	100	26.5	99
10	50	403	650	50	75	31.9	170
11	35	651	995	35	50	36.9	332
12	20	996	1420	20	35	40.7	784
13	8	1421	2003	8	20	43.0	2557
14	0.1	2004	3578	0.1	20	44.0	

CALCULATION OF AVERAGE MOBILITY RATIO

MANLOVE FIELD

DATA FROM J. WILLIAMS NO. 4

SAMPLE NUMBER	POROSITY FRACTION	PERM Md	Kw @ Sw = 1	Sg MAX FRACTION	Krg(r wat) @ Sg MAX	Krg(r air) @ Sg MAX	Krw(r air) @ SW=1	Krw/Krg	M = Kw*Ug/ Kg*Uw
C 145	0.073	12.5	8.36	0.564	0.390	0.261	0.669	2.56	0.051
C 146	0.146	715	675	0.567	0.314	0.296	0.944	3.18	0.064
C 147	0.086	65.8	52.6	0.472	0.439	0.351	0.799	2.28	0.046
C 148	0.109	87.4	73.7	0.525	0.427	0.360	0.843	2.34	0.047
								AVG	0.052

Ug =	0.0154
Uw=	0.78
Ug/Uw=	0.02

Table 3

CALCULATION OF CUSHION GAS AND NON-RECOVERABLE GAS

MANLOVE FIELD

SEASONAL DATA									STILES' RECOVERY FACTORS			TOP GAS AND TOTAL CUSHION GAS		RECOVERABLE AND NON-RECOVERABLE GAS		RECOVERABLE CUSHION GAS
SEASON [a]	START DATE [b]	END DATE [c]	DAYS [d]	STARTING INVENTORY Mscf [e]	WDRAWAL VOLUME Mscf [f]	INJECTION VOLUME Mscf [g]	END OF SEASON WGR B/MMscf [h]	PER CENT REC. PCT. [i]	CONF. FACTOR Fraction [j]	TOP GAS RECOV. FACTOR* Fraction [k]	TOTAL RECOV. FACTOR** Fraction [l]	TOP GAS Mscf [m]	TOTAL CUSHION GAS Mscf [n]	TOTAL RECOVER-ABLE GAS Mscf [o]	NON RECOVER-ABLE GAS Mscf [p]	RECOVERABLE CUSHION GAS Mscf [q]
90 INJ.	4/23/90	12/6/90	227	112,901,192		27,112,540										
90-91 WD	12/6/90	4/14/91	129	140,013,732	31,386,349		135	22.4	0.75	0.264	0.297	36,893,618	103,120,114	41,584,078	98,429,654	4,690,460
91 INJ.	4/14/91	12/9/91	239	108,627,383		31,109,576										
91-92 WD	12/9/91	4/20/92	133	139,736,959	29,111,043		115	20.8	0.73	0.257	0.289	35,842,530	103,894,429	40,395,160	99,341,799	4,552,630
92 INJ.	4/20/92	12/14/92	238	110,625,916		30,737,478										
92-93 WD	12/14/92	3/3/93	79	141,363,394	28,503,316		225	20.2	0.59	0.208	0.234	29,332,904	112,030,490	33,028,143	108,335,251	3,695,239
93 INJ.	4/23/93	12/13/93	234	112,860,078		30,610,919										
93-94 WD	12/15/93	3/11/94	86	143,470,997	26,630,647		105	18.6	0.69	0.243	0.273	34,791,717	108,679,280	39,202,015	104,268,982	4,410,298
94 INJ.	5/26/94	12/12/94	200	116,840,350		26,657,162										
94-95 WD	12/15/94	3/10/95	85	143,497,512	26,586,856		140	18.5	0.61	0.215	0.242	30,780,216	112,717,296	34,663,259	108,834,253	3,883,043
95 INJ.	3/12/95	12/3/95	266	116,910,656		26,976,039										
95-96 WD	12/5/95	3/3/96	89	143,886,695	27,797,110		145	19.3	0.63	0.222	0.249	31,870,903	112,015,792	35,896,853	107,989,842	4,025,950
96 INJ.	3/12/96	12/2/96	265	116,089,585		29,012,259										
96-97 WD	12/3/96	3/4/97	91	145,101,844	25,950,844		150	17.9	0.59	0.208	0.234	30,108,633	114,993,211	33,901,595	111,200,249	3,792,962
97 INJ.	3/7/97	12/3/97	271	119,151,000		28,370,000										
97-98 WD	12/4/97	3/4/98	90	147,521,000	26,850,000		125	18.2	0.62	0.218	0.246	32,159,578	115,361,422	36,219,356	111,301,644	4,059,778
98 INJ.	3/6/98			120,671,000												
98-99 WD	12/17/98															

*TOP GAS RECOVERY FACTOR FROM 250 BBL/MMSCF LIMIT
**TOTAL GAS RECOVERY FACTOR FROM 600 BBL/MMSCF LIMIT

Table 4

LIST OF FIGURES

DISTRIBUTION OF INVENTORY

MANLOVE FIELD

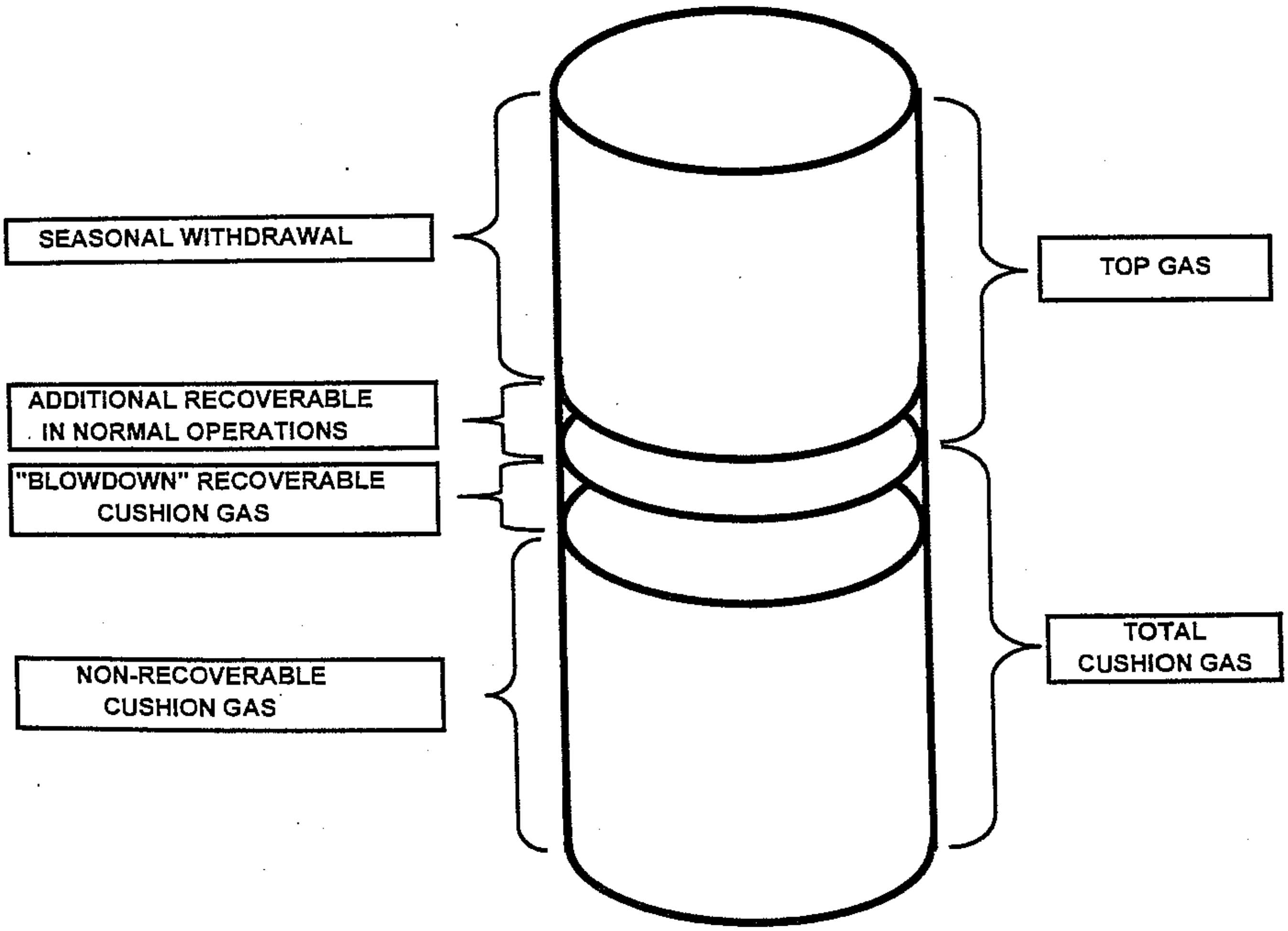


Figure 1

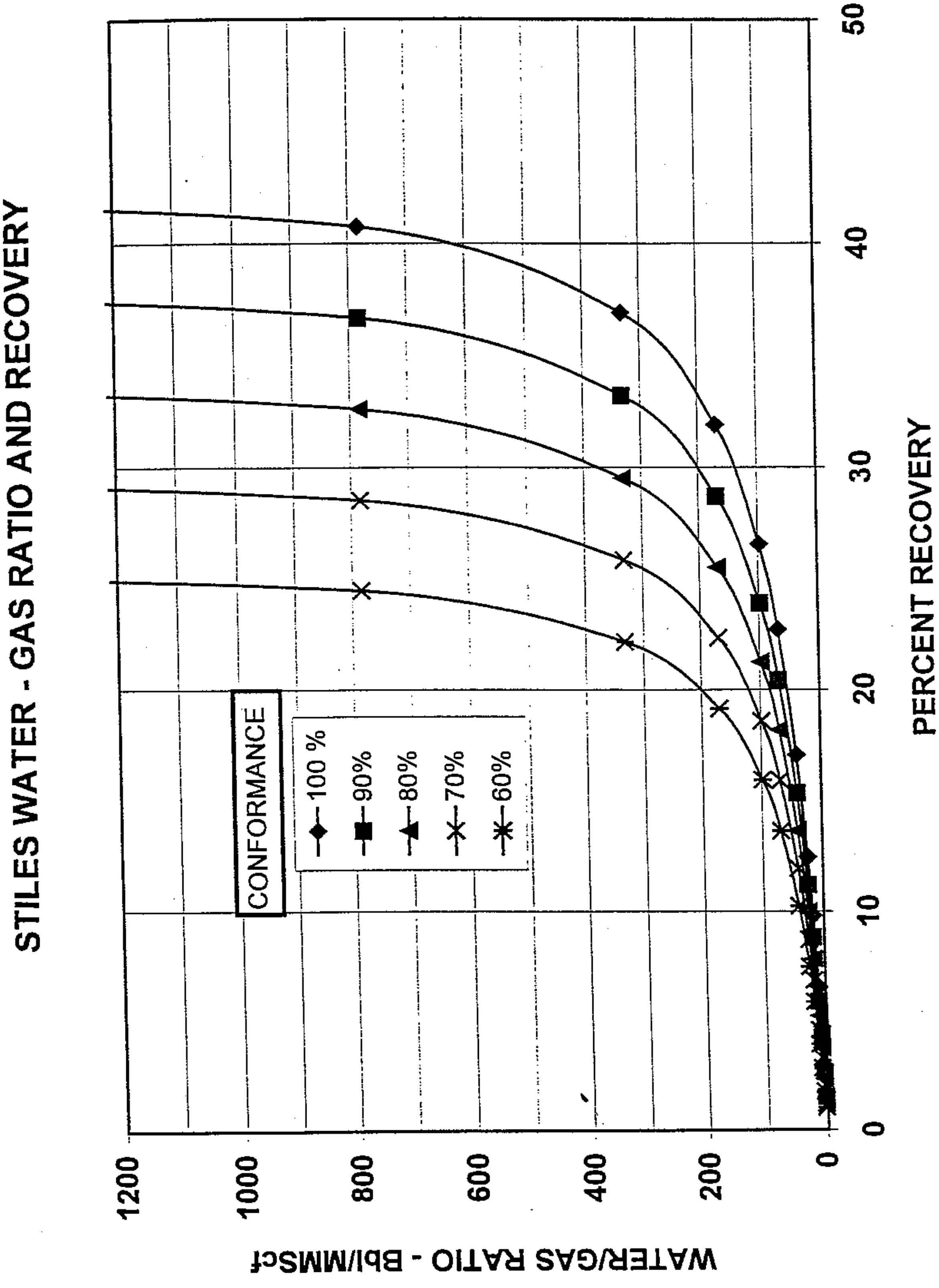

STILES WATER - GAS RATIO AND RECOVERY
CONFORMANCE
100 %
90%
80%
70%
60%
PERCENT RECOVERY
0
10
20
30
40
50
WATER/GAS RATIO - Bbl/MMScf
0
200
400
600
800
1000
1200

Figure 2

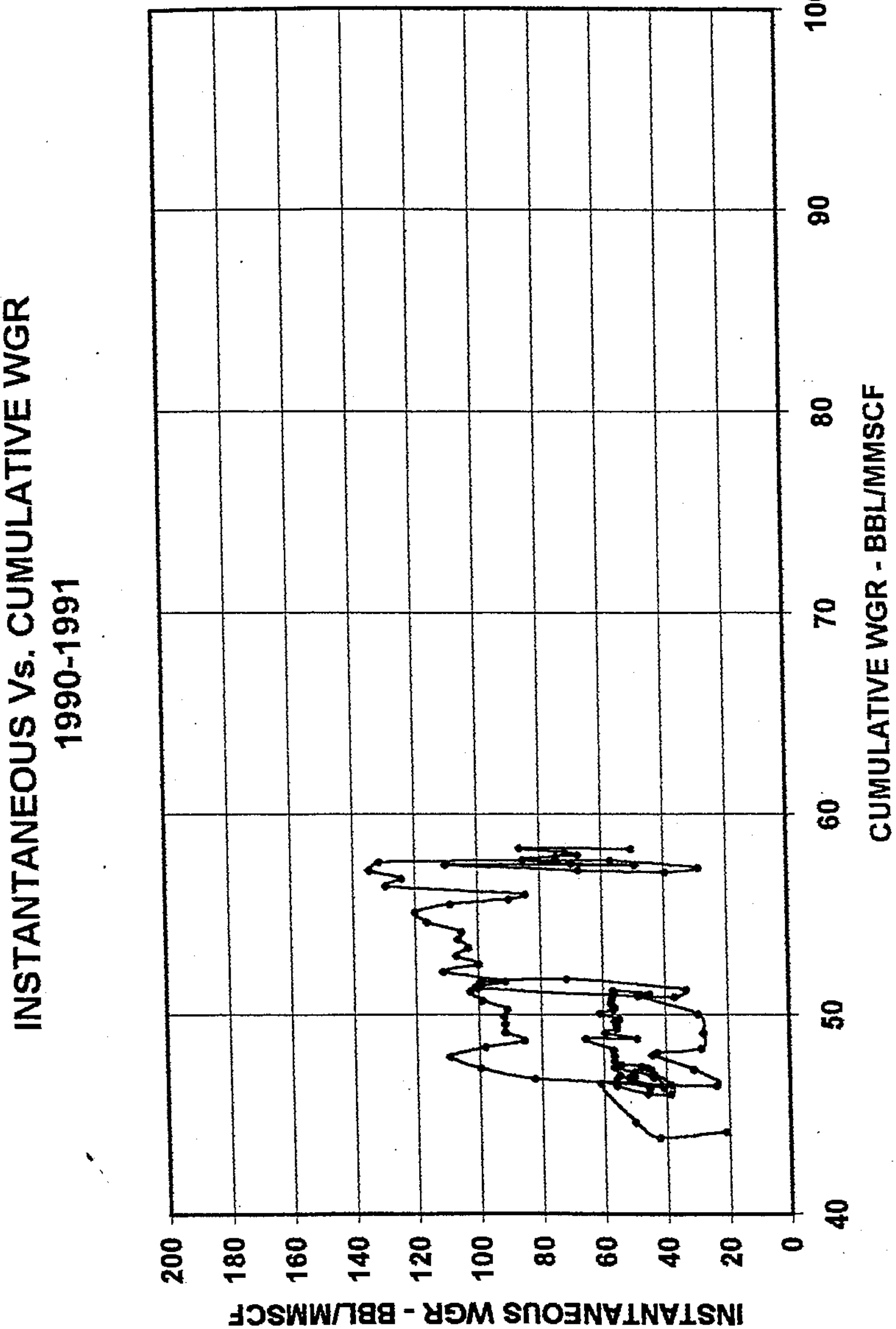
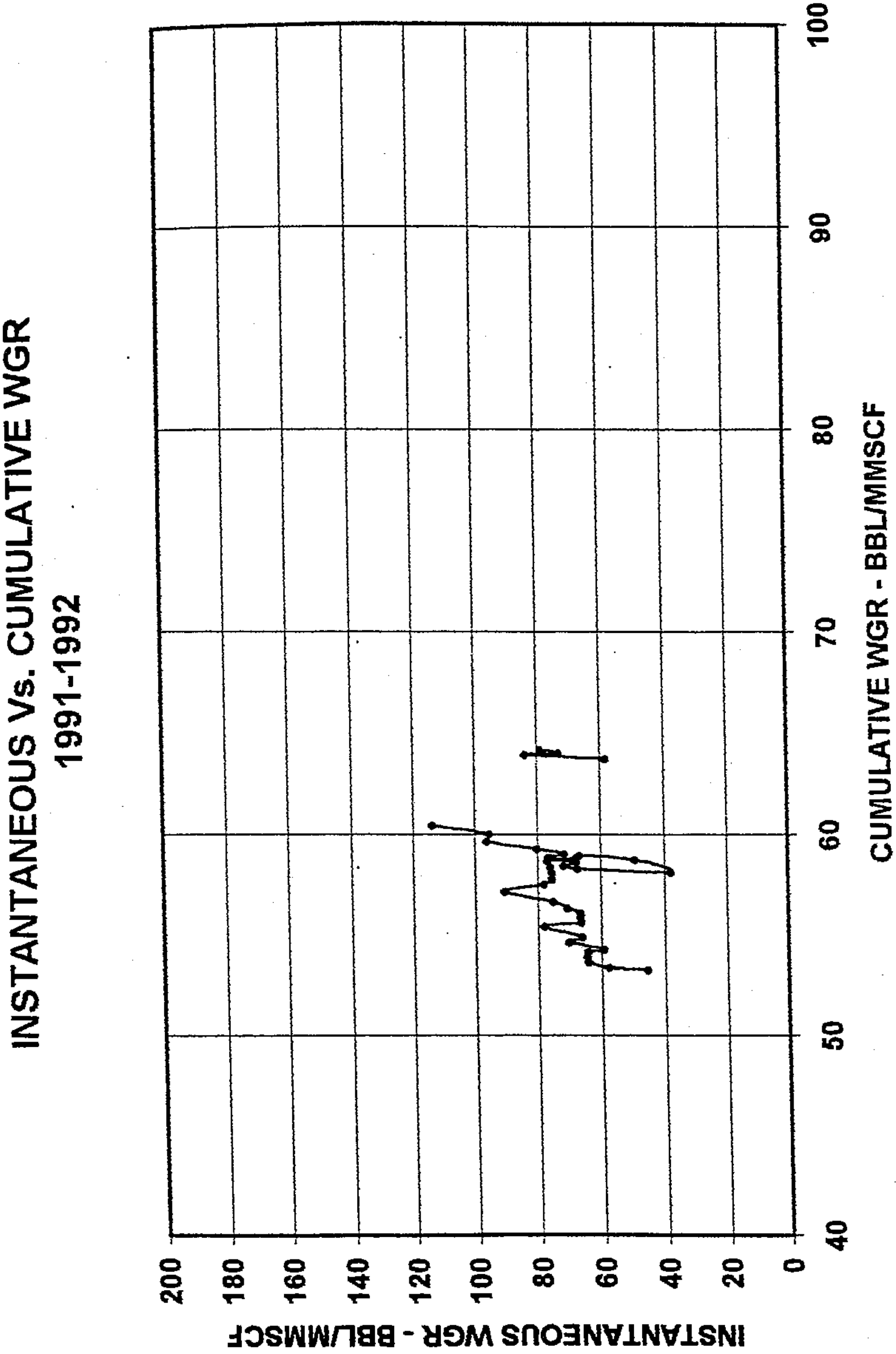

INSTANTANEOUS Vs. CUMULATIVE WGR
1990-1991
INSTANTANEOUS WGR - BBL/MMSCF
CUMULATIVE WGR - BBL/MMSCF
0
20
40
60
80
100
120
140
160
180
200
40
50
60
70
80
90
100

Figure 3


INSTANTANEOUS Vs. CUMULATIVE WGR
1991-1992
CUMULATIVE WGR - BBL/MMSCF
INSTANTANEOUS WGR - BBL/MMSCF
40
50
60
70
80
90
100
0
20
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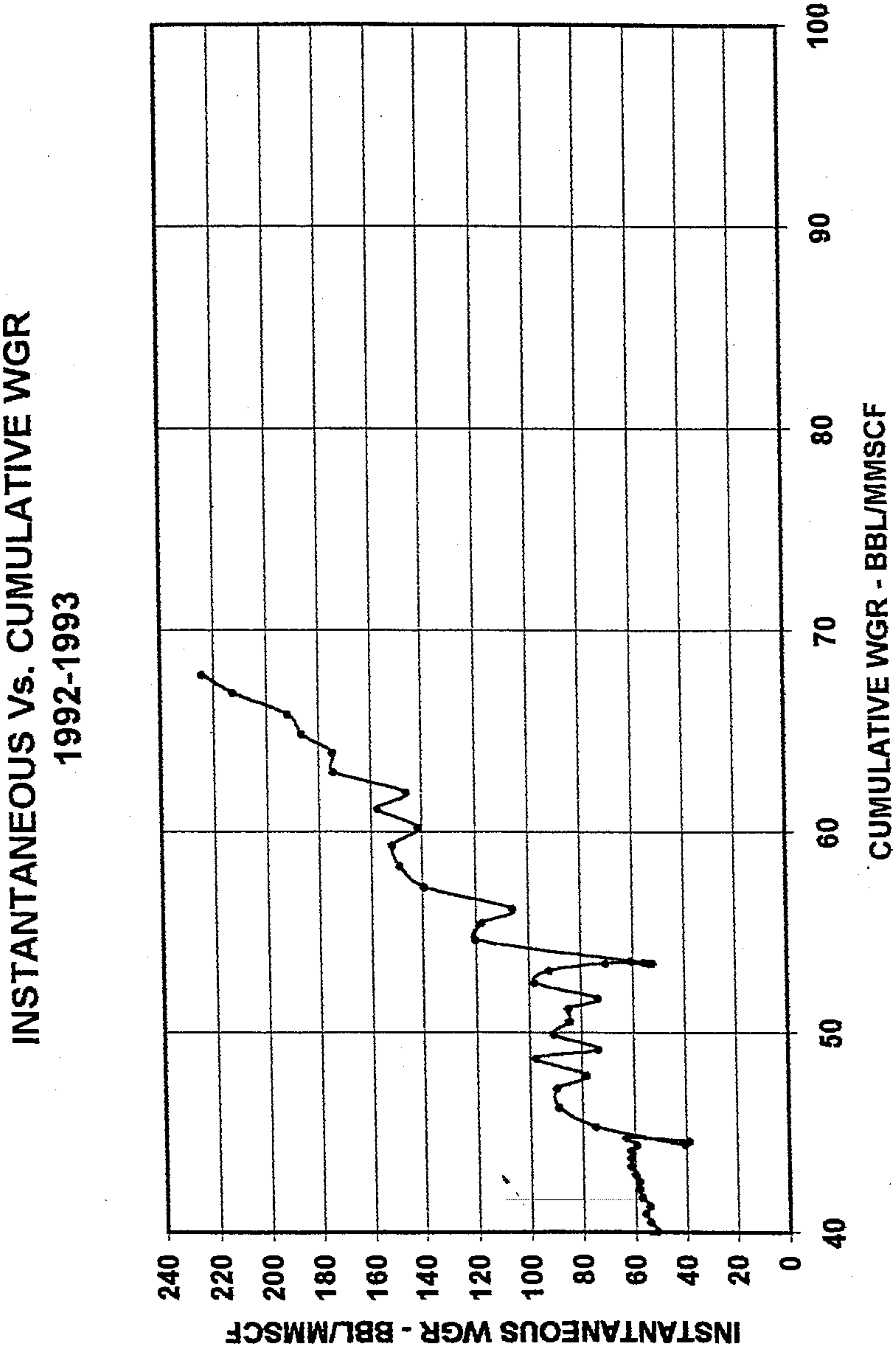
60
80
100
120
140
160
180
200

Figure 4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1992-1993
INSTANTANEOUS WGR - BBL/MMSCF
CUMULATIVE WGR - BBL/MMSCF
0
20
40
60
80
100
120
140
160
180
200
220
240
40
50
60
70
80
90
100

Figure 5

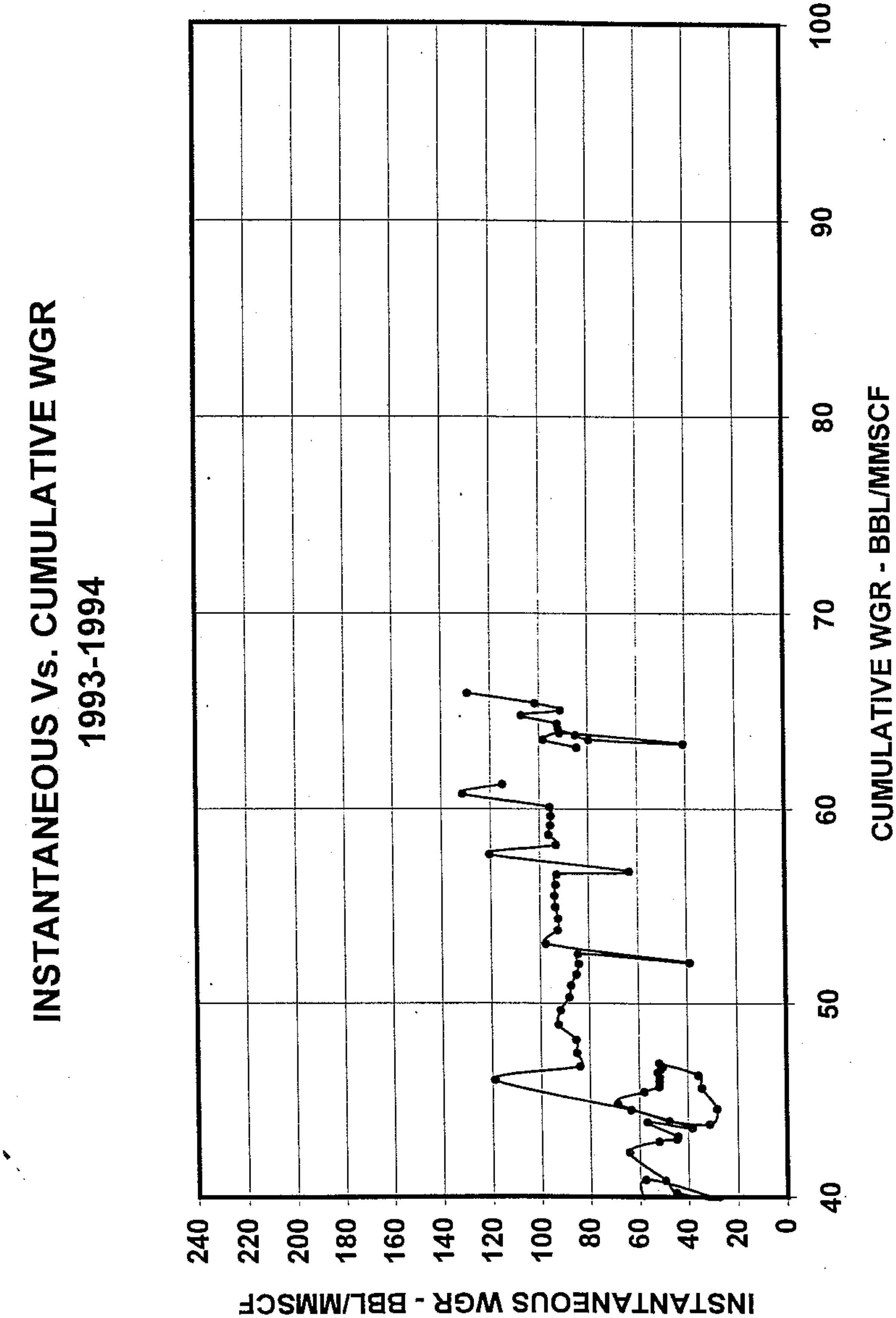
INSTANTANEOUS Vs. CUMULATIVE WGR
1993-1994
INSTANTANEOUS WGR - BBL/MMSCF
CUMULATIVE WGR - BBL/MMSCF
240
220
200
180
160
140
120
100
80
60
40
20
0
40
50
60
70
80
90
100

Figure 6

INSTANTANEOUS Vs. CUMULATIVE WGR
1994-1995

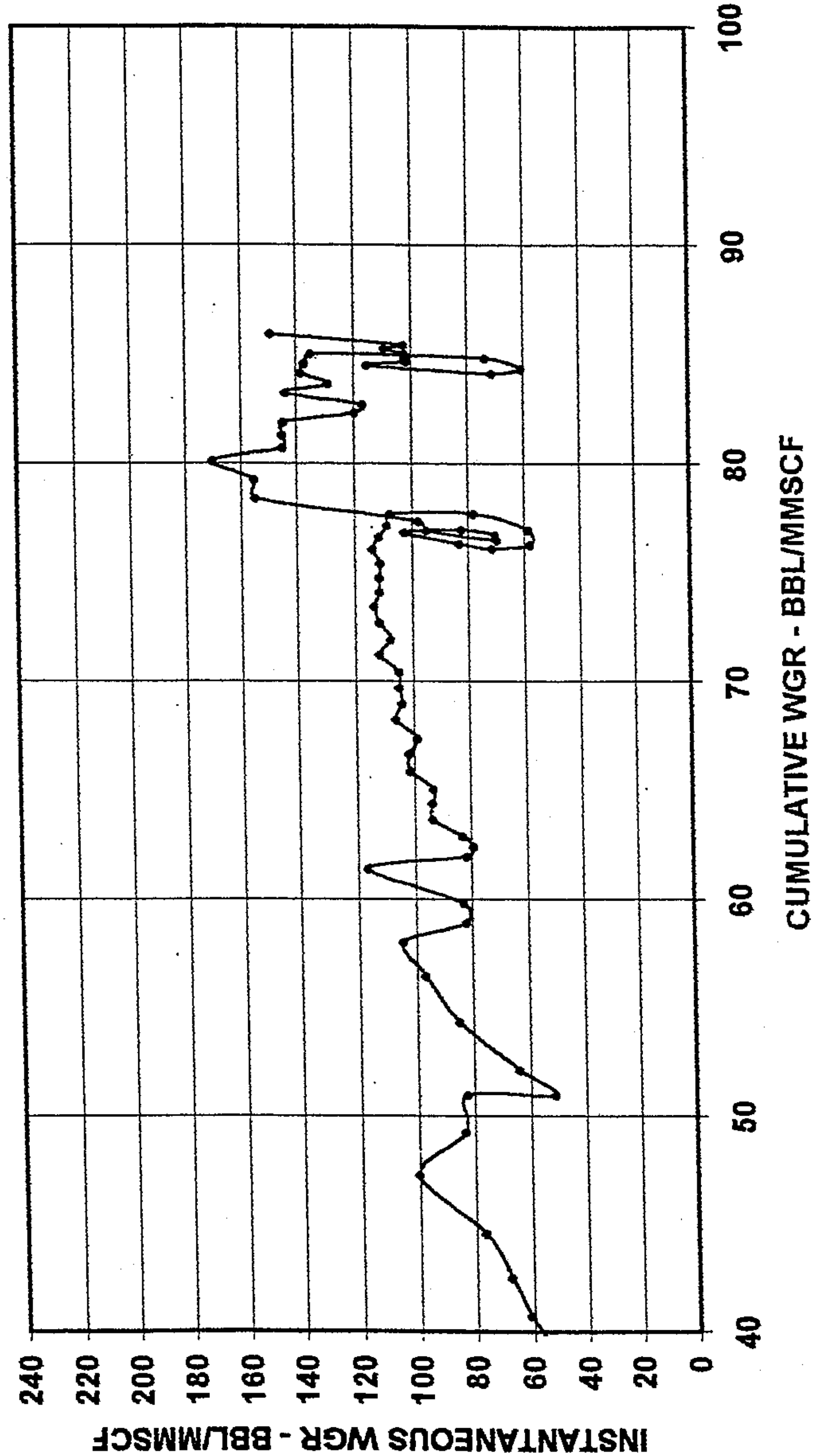

Figure 7

PGL Ex. TLP-1.1

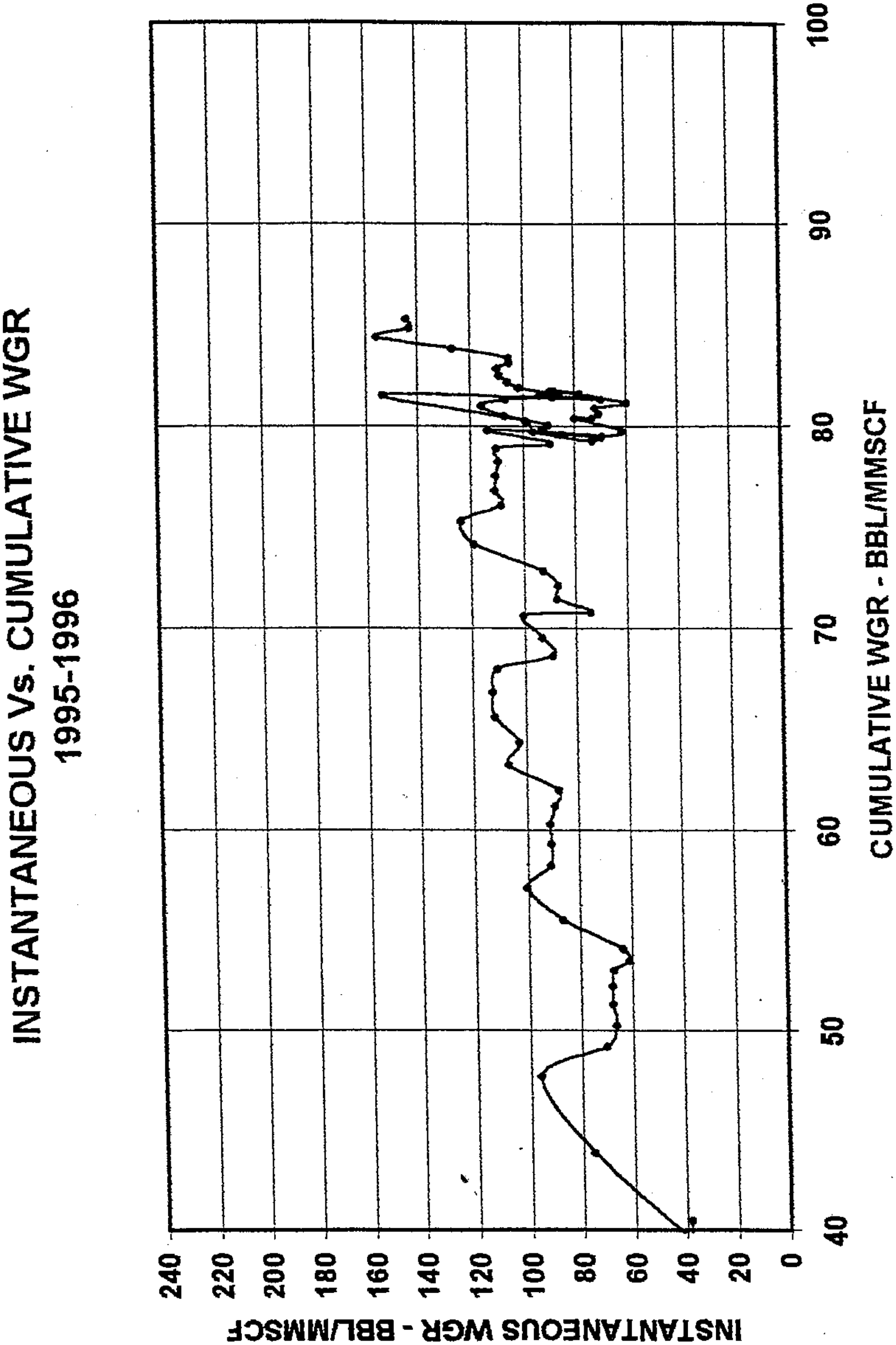

Figure 8

INSTANTANEOUS Vs. CUMULATIVE WGR
1996-1997

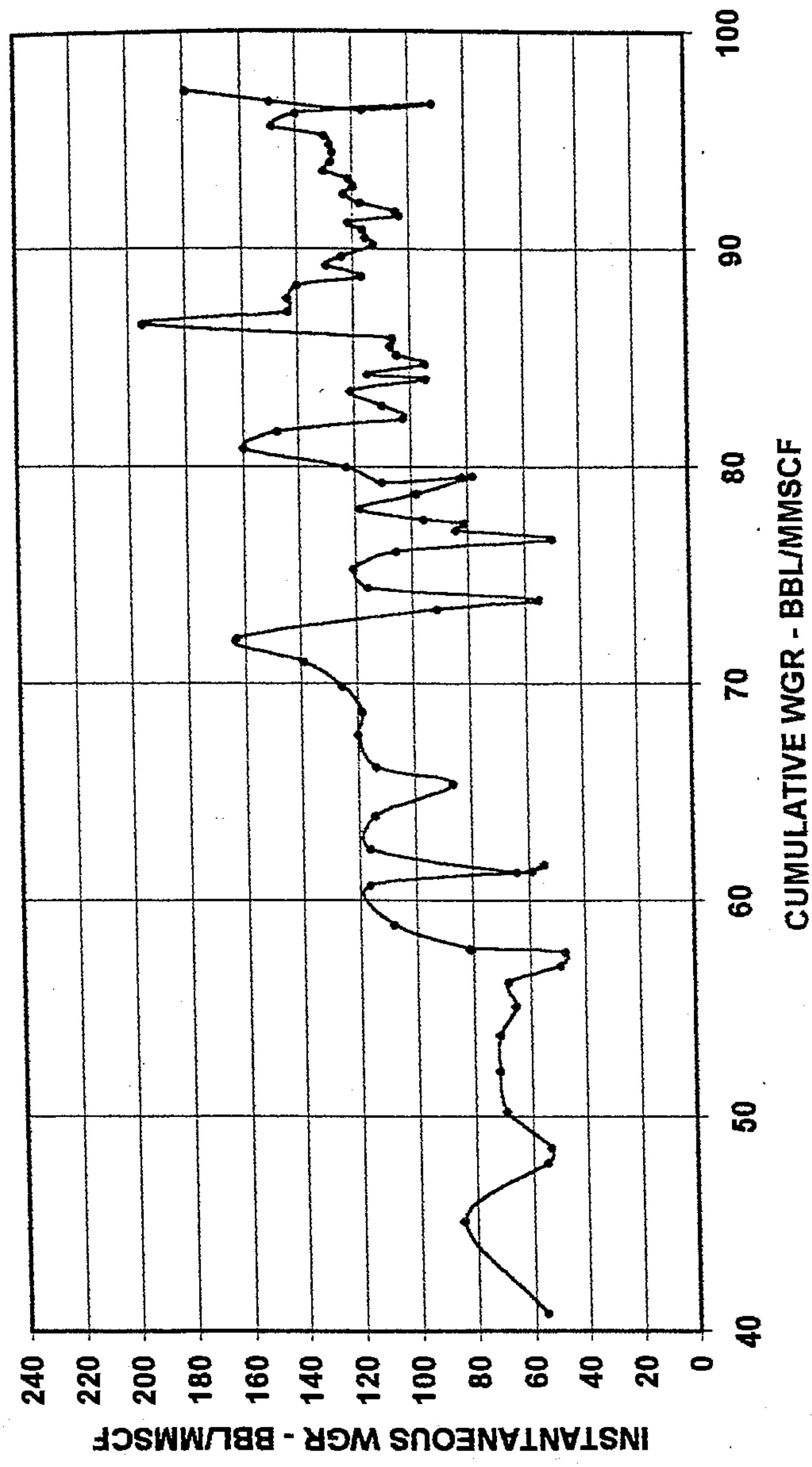

Figure 9

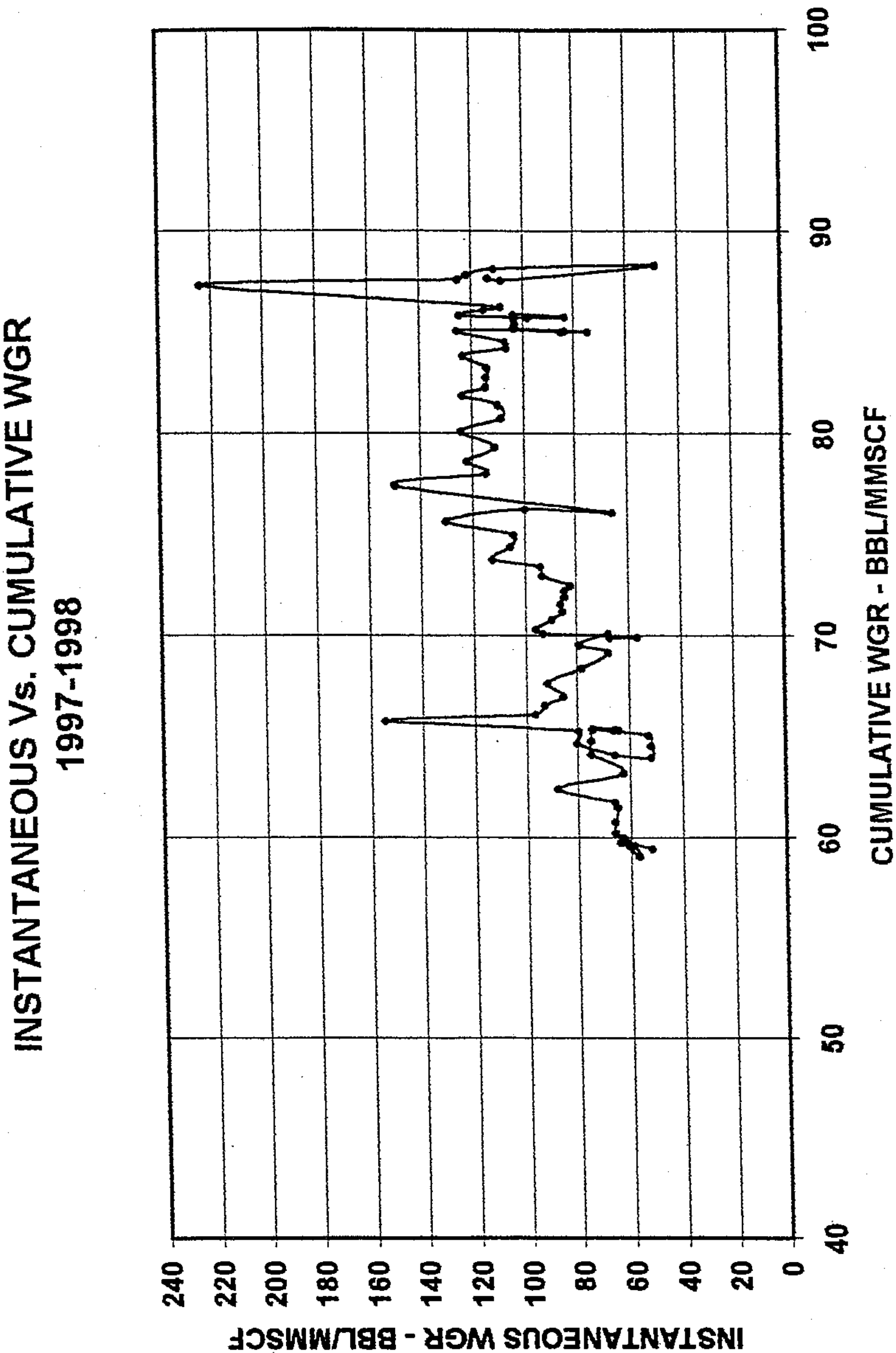
INSTANTANEOUS Vs. CUMULATIVE WGR
1997-1998
CUMULATIVE WGR - BBL/MMSCF
INSTANTANEOUS WGR - BBL/MMSCF
40
50
60
70
80
90
100
0
20
40
60
80
100
120
140
160
180
200
220
240

Figure 10

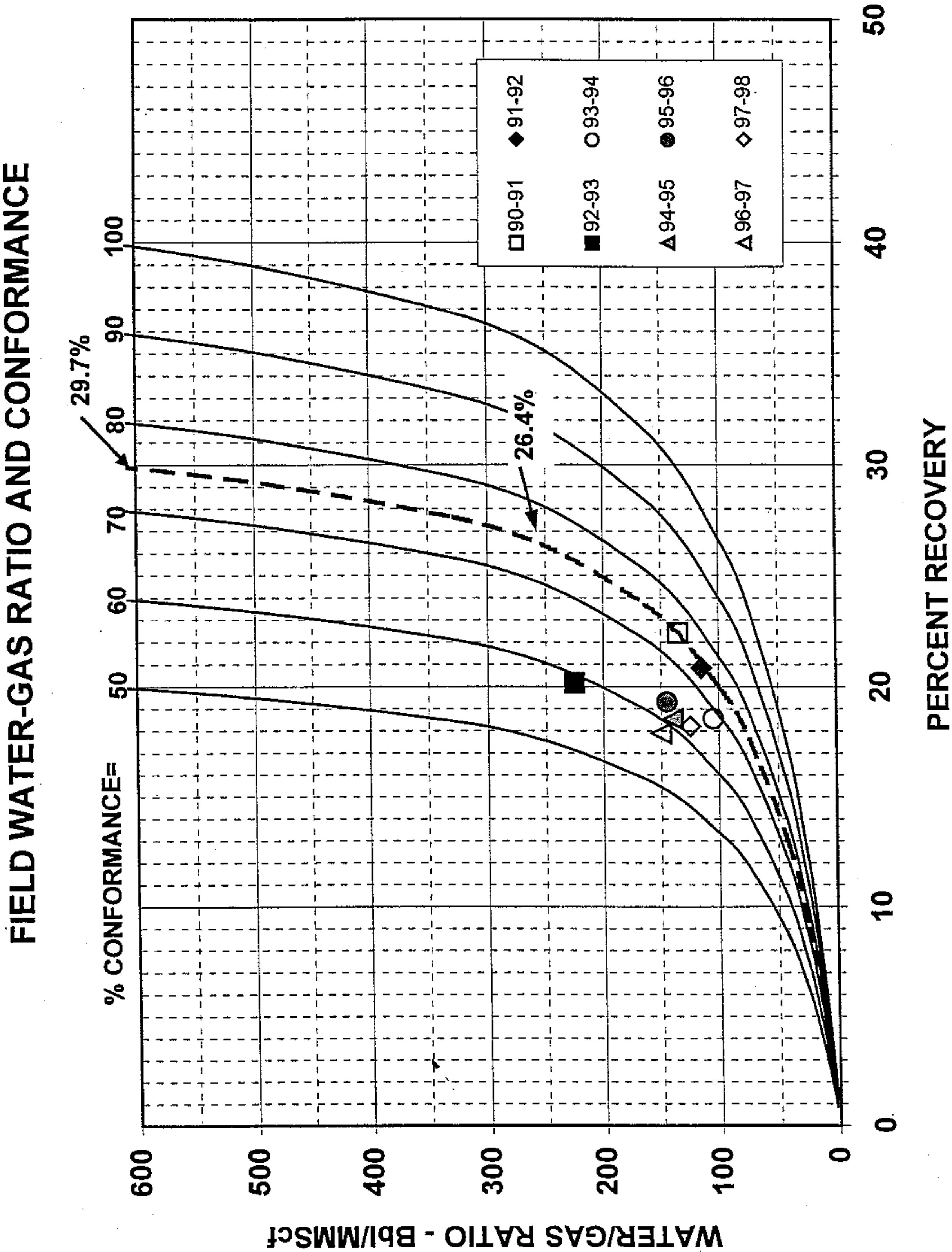
FIELD WATER-GAS RATIO AND CONFORMANCE
% CONFORMANCE=
100
90
80
70
60
50
29.7%
26.4%
90-91
91-92
92-93
93-94
94-95
95-96
96-97
97-98
WATER/GAS RATIO - Bbl/MMScf
600
500
400
300
200
100
0
PERCENT RECOVERY
0
10
20
30
40
50

Figure 11

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September 30, 2005

Mr. Tom Puracchio
Mr. Ted Kronas
Peoples Energy
230 County Road 2800N
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Gentlemen:

The decline in field peaking capacity that occurred near the end of the 2004-05 withdrawal cycle has led to a re-evaluation of cushion gas requirements. The attached report "Supplement To The Manlove Field Trapped Gas Report" outlines the reason cushion gas is required to replace trapped gas, cites Manlove studies that quantify cushion gas requirements, and gives my recommendation for cushion gas for injection season 2006.

The report is in support of my memo dated July 29 2005, which stated that a minimum of 3.5% of cushion gas is required to maintain field performance. It includes field performance data since the previous report was issued, and it utilizes studies cited in the previous report to recommend cushion gas injection for 2006.

Sincerely,

Charles R. Connaughton

Charles R. Connaughton, P. E.

Supplement To The Manlove Field Trapped Gas Report

Executive Summary

Acting as Reservoir Consultant to Peoples Energy, I issued a report titled "Manlove Field Trapped Gas Report" dated February 3, 2003. This report is written as a supplement to that report. Some details from that report are included for continuity, but the main purpose of this report is to show how recent performance indicates that an increase in cushion gas to at least 3.5% of injection is necessary if field performance is to be maintained.

Lost gas is an inevitable consequence of storing gas in an aquifer reservoir. Withdrawal performance indicates that lost gas has ranged from almost 7% of injected volume in the early 1990's to as low as 1.4% in 2000-02. On that basis, a replacement gas volume of 2% of injection was considered a reasonable amount for 2003-2005.

Performance improved in the 2002-03 and 2003-04 withdrawal seasons, but declined sharply in 2004-05. This recent decline indicates a 2% replacement volume is no longer adequate to maintain long-term field performance.

The amount of lost gas has, and will, vary from year to year because operating practices and working volumes vary from year to year. The 2% value was low compared with previous needs, and it is low compared with amounts shown in simulation studies of the field.

Replacing "lost gas" during injection is necessary to maintain performance in any aquifer gas-storage operation. Without "lost gas" replacement, the working gas volume decreases and a long-term deterioration in field performance occurs as evidenced by:

A decline in peaking capacity.
A decline in late season deliverability.
A decline in seasonal withdrawal volumes.
An increase in water-gas ratios.

A decline in peaking capacity and working gas occurred in the 2004-05 withdrawal season. This decline in peaking capacity indicates recent cushion gas allotments have not been adequate to maintain long-term field performance.

It is recommended that cushion gas be increased to at least 3.5% of injection in the 2006 injection season. Withdrawal performance in 2005-06 should be monitored to determine the adequacy of this volume.

Introduction

Acting as Reservoir Consultant to Peoples Energy, I issued a report titled "Manlove Field Trapped Gas Report" dated February 3, 2003. That report, referred to here as the "previous report" dealt in depth with gas loss in aquifer gas storage. It described the problem, attempted to quantify gas loss at Manlove using performance data, and discussed cushion gas requirements based on performance and reservoir studies.

This report is written as a supplement to that report. Some details from that report are included for continuity, but the main purpose of this report is to show how recent performance indicates an increase in cushion gas is necessary if field performance is to be maintained.

Gas Storage in an Aquifer

Gas is stored at the Manlove field in the Mt. Simon formation at a depth of about 4000 feet. The storage reservoir is a consolidated rock formation with a porosity of about 13 percent. All of the pore space was originally filled with water.

Gas is injected into the pore space using a pressure at the bottom of the injection well that is about 200 psi above the original pressure. Pressure in the storage zone is above aquifer pressure most of the time. When the field pressure is above aquifer pressure, gas and water will move from the gas zone to the lower pressure aquifer, and the pressure in the gas zone will fall. If the field pressure in the gas zone is below aquifer pressure, water will move into the gas storage zone.

Pressures are necessarily above the initial aquifer pressure most of the time in Manlove. During this time, gas is continually moving from the working gas area into pores that previously had little or no gas saturation. A large fraction of that gas will become trapped (lost). If this lost gas is not replaced, the effective working gas will decrease and a long-term deterioration in field performance will occur as evidenced by:

1. A decline in peaking capacity.
2. A decline in late season deliverability.
3. A decline in seasonal withdrawal volumes.
4. An increase in water-gas ratio.

Historic Manlove Volumes

Inventory and Seasonal Volumes

A review of past Manlove inventories, injection and withdrawal volumes helps to understand their significance to the discussion of trapped or lost gas. Table 1 shows these values since the start of the 1990 injection season. These are "Oil Field Manager" inventories, and they may differ slightly from accounting inventories.

Since 2002, the inventory has grown from 160.97 Bscf to a planned 166.34 Bscf at the end of injection 2005. In this period, seasonal injection and withdrawal volumes have not varied significantly.

The previous report analyzed changes in inventory and changes in seasonal withdrawal to try to quantify trapped gas. Different periods were used based on apparent different relationships between inventory growth and working gas. That analysis indicated the following:

PERIOD	Bscf INCREASE IN SEASONAL WITHDRAWAL/ Bscf INVENTORY INCREASE
1990 TO 1994	- 0.95
1994 TO 2001	+ 0.47
1996 TO 2001	+ 0.60
1996 TO 2000, LESS 1999	+ 0.98

The analysis concluded that trapped gas was indicated to be almost 7% of injection from 1990 to 1994, when the ratio of the increase in seasonal withdrawal to the increase in inventory was negative. From 1996 to 2000 the ratio was near unity and it was concluded that very little gas was trapped.

Using a similar technique for the last three years is instructive:

PERIOD	Bscf INCREASE IN SEASONAL WITHDRAWAL/ Bscf INVENTORY INCREASE
2001 to 2004	0.00

In this period inventory increased by about 6 Bscf, but withdrawal volumes stayed about the same. Using the similar type analysis, the 6 Bscf became trapped and did not contribute to field performance. This is about 5.6% of injection over the period.

As noted in the previous report, there are uncertainties in the above analysis. The basic assumption is that seasonal withdrawal is the working gas. Seasonal withdrawal is subject to demand, and is only an indication of working gas.

This analysis and the decline in peaking capacity noted in the 2004-05 withdrawal (discussed later) indicate recent cushion gas allotments have not been adequate to maintain field performance.

It is recommended that cushion gas be increased to at least 3.5% of injection in the 2006 injection season. Withdrawal performance in 2005-06 should be monitored to determine the effectiveness of this volume.

Working Gas at the End of Injection

"Working gas" at the end of injection is injected gas plus some adjustment for under- or over-withdrawal the previous season. The working gas volume actively influences withdrawal performance. Attempts are continually made to quantify a "working gas" at the end of injection as an indicator of seasonal withdrawal volume and of peaking capacity in the upcoming withdrawal season. This is difficult, because it depends on injection and withdrawal (WD) volumes from the preceding season and probably from several previous seasons.

In an attempt to quantify working gas volumes for recent years, seasonal injection and WD statistics were extensively analyzed from 1998 to the present looking for a relationship between injection, previous WD, and the following WD season's performance. No relationship could be found. There are two main reasons for this: 1) Total season WD varies widely and has been controlled more by demand than capacity, and 2) As a result, excess under/over WD occurs alternately in many seasons and our calculations can not handle this adequately.

Correlations of peaking capacity and late season peak decline with "working gas" have not been quantitatively successful. This is probably because our definition of "working gas" is too simple, and does not consider the many factors that affect withdrawal volumes or operations in previous seasons. However, the "working gas" concept is a useful indicator of reservoir performance.

Deliverability

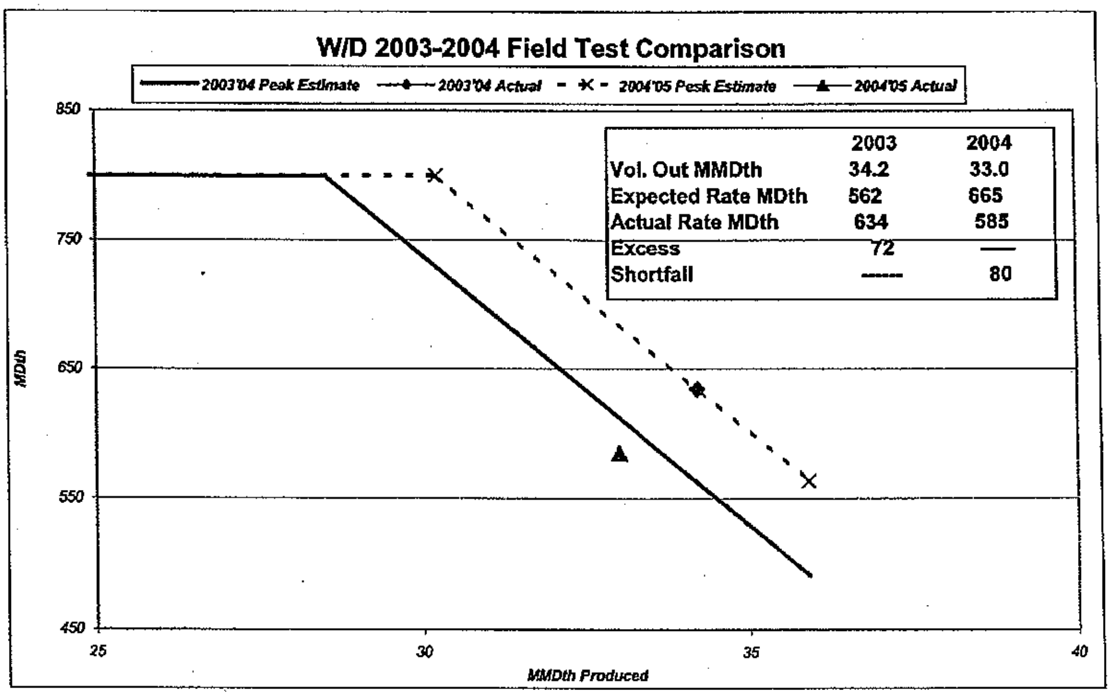
Peaking field effects

One of the major purposes of the Manlove gas storage reservoir is to supply peak gas demands for Chicago. For many years, when a peak was called for, the field was produced with a gathering system pressure of 925 psi to meet pipeline pressure requirements. The maximum field rate was limited to 800 MMscf/D by the capacity of the transportation system. The present field gathering system allows lower withdrawal system pressures, and field testing is now done at nominal operating pressures. The capacity of the transportation system is greater. However, the field's maximum deliverability is still depicted as 800 MMscf/D for comparison.

Deliverability in 2003'04 and 2004'05

The previous report discussed the peak deliverability of the field from 1990 to 2002. Inventory grew from 141 to 161 Bscf during this period. The "break point" in the deliverability curve as determined by field tests increased from 19 Bscf to 26.7 Bscf. The break point increased throughout the period except for after the 1994-95 withdrawal season. It was noted that a 20 Bscf increase in inventory increased the break point 7.7 Bscf.

Deliverability did not follow predictions in 2003-04 or 2004-05, as shown in the figure below:



The 2003-04 peak estimate was based on 2002-03 performance. The expected peak rate was 562 MDth/D at 34.2 MMDth withdrawal. The field actually produced 634 MDth/D, 72 MDth/D greater than predicted. This increase indicated that cushion volumes of about 2% for the last two years had been more than adequate for the operating conditions during that period.

The expected deliverability for 2004-05 was adjusted on the basis of the excellent 2003-04 performance. The expected rate at 33 MMDth withdrawal was 665 MDth/D, but the field only produced a disappointing 585 MDth/d, a rate slightly lower than the 2002-03 actual performance.

This decline in performance shows that, other operating parameters being equal, the recent cushion gas volumes have not been sufficient to maintain long-term field withdrawal performance.

This decline in performance is puzzling considering water-gas ratios (WGR's). Poorer gas deliverability performance is usually associated with increased WGR's. The season cumulative WGR was similar to recent seasons, and actually slightly lower than the last three seasons.

Another performance indicator is the rate of pressure decline in Well HBR3. The decline was similar to that in recent seasons until late in withdrawal when it accelerated rapidly. This would seem to be an indication of less effective gas in the central area of the field, but that is not consistent with lower WGR'S.

Trapped Gas

Definition

Trapped gas is gas that is immobile in the reservoir for withdrawal operations. A portion of any injected gas that invades water saturated pore space is trapped. Laboratory tests on Manlove cores show that until gas saturations reach at least 20 - 35 %, all of the gas is trapped during withdrawal. As gas saturations increase above those values, most of the additional gas is mobile. It has been estimated in past calculations of recoverable gas that 56 % of the gas in newly invaded pore space is trapped gas.

Historic Document Overview

Because storage is at pressures above aquifer pressure most of the year, gas is continually invading new pore space. To avoid deterioration in reservoir performance, this gas must be replaced with cushion gas. Several studies have been done using reservoir simulation to determine the amount of trapped gas that must be replaced with cushion gas each year to maintain peaking performance. Reservoir simulation studies have been performed on Manlove for Peoples since the late 1970's by Core Laboratories and it successors Petresim, Smedvig and ROXAR.

Petresim used the simulator to evaluate the need for trapped gas replacement to maintain peaking capacity in a 1993 study. According to a 1995 memo attached to the 1994-95 Annual Report, that study concluded (quoted):

1. Injecting approximately 1 Bscf of cushion gas per year is required to maintain field peaking capacity.
2. Without additional cushion gas, peaking capacity will decline at about 36 MMscf/D per year.

Working gas at the time of the study was about 28 Bscf/year, and the inventory was 143 Bscf. The recommended "cushion" gas is about 3.5 % of the working gas.

ROXAR used the simulator in 1999 to examine the feasibility of raising the working gas volume to 33.8 Bscf. The study found that 35.8 Bscf of injection was required to maintain end of season peaking capacity. The 2 Bscf of make-up gas represent more than 5 % of injection.

These injection and withdrawal volumes are only slightly less than those of the last three years. The ROXAR study indicates that present field operations require about 2 Bscf of make-up (cushion) gas to maintain peaking.

It should be realized that the predictions of the simulators are for the specific operating conditions and injection/withdrawal schedules that were imposed, and that those conditions did not change from year to year in the predictions. This is certainly not the situation in the field.

Trapped Gas Requirement

Evidence of Recent Trapped Gas Volumes

Manlove personnel have done an informal study that compared 1990 individual well responses of tubing pressure, annular pressure, water-gas ratio and daily withdrawal rate to 2000 data. Performance matches were made by increasing the 1990 inventory by 11.5 Bscf. From 1990 to 2000, inventory grew by 16.8 Bscf. Using my interpretation, the lost gas over this period was 5.3 Bscf. Total injection over the ten year period was 286 Bscf. The lost gas was 2 % of the injected volume, somewhat less than indicated by the simulation studies.

Using a similar history-matching technique, Manlove personnel have compared tubing pressure response in the HBR 3 well in 2000 with the early part of the 2002 withdrawal season. They found that a 3.5 Bscf increase in the 2000 inventory resulted in a match. Inventory grew by 4.4 Bscf over the period. By my analysis, the indicated gas loss is 0.9 Bscf, about 1.3 % of the injected volume, and again less than indicated by the simulation studies.

Yearly Percentage

Various analyses discussed here and in the previous have implied lost gas percentages as being near none (which is not possible in the long term in this type of gas storage reservoir) to as high as 6.8 percent of injection. Reservoir simulation studies have shown that injections 3.5 to 5% greater than withdrawals are required to maintain or restore peaking capacity. Studies done by Manlove personnel that consider field history can be interpreted to mean losses are in the 1.4 to 2% range.

All of these interpretations show that the lost gas requirement varies for different operating conditions and seasonal injection and withdrawal volumes. The 2004-05 withdrawal performance indicates that make–up volumes have not been sufficient to maintain peaking and working gas volumes. The present injection season plan calls for 2 % cushion gas volume. At the current injection volumes, 2 % of injection will be about 0.7 Bscf/year. Considering performance in the last withdrawal season and the above studies, this amount will not be adequate to maintain field performance.

It is recommended that for planning purposes, the 2006 injection volume should include 3.5% cushion gas. Cushion gas requirements should be reviewed and adjusted each year after the withdrawal season. An adjustment in the above value may be necessary after the 2005-06 withdrawal season.

MANLOVE FIELD INVENTORY from OIL FIELD MANAGER (OFM)

WITHDRAWAL(w)/ INJECTION(i) SEASON	STARTING INVENTORY Bscf	FINAL INVENTORY Bscf	WITH-DRAWAL Bscf	INJEC-TION Bscf	W/D Replacement Bscf	OVER W/D Bscf
i90	113.71	140.82		27.11		
w90	140.82	109.76	31.06			3.94
i91	109.76	140.91		31.15	0.09	
w91	140.91	112.02	28.88			-2.26
i92	112.02	142.70		30.68	1.79	
w92	142.70	113.97	28.73			-1.95
i93	113.97	144.53		30.56	1.83	
w93	144.53	117.89	26.64			-3.92
i94	117.89	144.33		26.44	-0.20	
w94	144.33	117.72	26.60			0.17
i95	117.72	145.08		27.35	0.75	
w95	145.08	116.52	28.56			1.21
i96	116.52	145.92		29.41	0.85	
w96	145.92	120.32	25.60			-3.80
i97	120.32	148.72		28.40	2.80	
w97	148.72	121.87	26.85			-1.55
i98	121.87	154.38		32.51	5.65	
w98	154.38	122.03	32.34			-0.16
i99	122.03	156.45		34.42	2.07	
w99	156.45	125.24	31.21			-3.21
i00	125.24	156.55		31.31	0.10	
w00	156.55	120.39	36.17			4.85
i01	120.39	158.77		38.39	2.22	
w01	158.77	128.08	30.69			-7.69
i02	128.08	160.97		32.89	2.20	
w02	160.97	125.08	35.89			3.00
i03	125.08	163.22		38.14	2.25	
w03	163.22	127.47	35.75			-2.39
i04	127.47	164.85		37.38	1.63	
w04	164.85	129.07	35.78			-1.60
i05	129.07	166.34		37.27*	1.49	

*SCHEDU LED

TABLE 1

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March 17, 2007

Mr. Tom Puracchio
Mr. Ted Kronas
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230 County Road 2800N
Fisher, Illinois 61843

Subject: Cushion Gas Requirement for 2007 Injection

Gentlemen:

The decline in field peaking capacity that was experienced near the end of the 2004-05 and 2005-06 withdrawal cycles was reversed and peaking capacity improved at the end of the 2006-07 withdrawal cycle. This reversal is probably in response to the continued injection of 3.5% cushion gas, some changes in injection and withdrawal schedules, and possibly to some other changes in operational procedures.

Present simulation studies have indicated that peaking capacity would continue to decline in the 2006-07 withdrawal season before beginning to improve in subsequent years with the current 3.5% cushion allocation. The precise reason for the unexpected improvement in 2006-07 season results cannot be isolated. However, it is unlikely this improvement would have occurred without the continued injection of 3.5% cushion gas.

Based on the field performance in the 2006-07 withdrawal season, the statements and conclusions in the above simulation report, previous studies citing the continued requirement for cushion gas, and the 2005 report "Supplement To The Manlove Field Trapped Gas Report", it is my recommendation that the cushion gas allocation again be a minimum of 3.5% of total injection for the 2007 injection season.

Sincerely,

Charles R. Connaughton

Charles R. Connaughton, P. E., TX and LA (not registered in Illinois)

CHARLES R. CONNAUGHTON

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May 30, 2008

Mr. Tom Puracchio
Mr. Ted Kronas
Peoples Energy
230 County Road 2800N
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Gentlemen:

I have reviewed Mr. Kronas' forecast for deliverability for the 2008-2009 withdrawal season. I am in agreement with his use of the data and the results of presented in his report. The deliverability forecast is a reasonable engineering estimate of peaking capability in the next withdrawal season.

I believe the cushion gas of 3 ½ % planned to be injected this 2008 injection season is adequate and necessary to achieve the above deliverability forecast and to maintain field performance in the 2008-2009 withdrawal season.

Sincerely,

Charles R. Connaughton

Charles R. Connaughton, P. E., TX, LA (not licensed in Illinois)
Reservoir Consultant – May 30, 2008

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