Oil production stabilization, minimizing gas pockets into flow line in oil wells with hydraulic lift system

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Summary

- The effects of vertical multiphase flow have been studied rigorously in efforts to optimize production in flowing wells.

- In this case history, the jet pump artificial lift system shows its capacity to handle gas flow through the pump.

- Gas pockets have often been a deterrent to continuously production.

- This case history, the well is operated with a multiple well control hydraulic lift system.

- Pressure pulsations in the return flowline were minimized by applying:

  •Variations in jet pump nozzle to throat geometry (area of nozzle to area of throat ratio).

  • Backpressure on the well discharge.

- The amount of gas can become large enough to reduce total fluid returns from the well.

-The primary concern is decreased fluid production rates and second the lack of returning fluid.

- Experience has indicated that gas to liquid ratios greater than 200 scf/bbl result in reduced jet pump efficiencies.

- This case history provides an analysis of a well in Southern Colombia, detected to have intermittent flow or batch production.

- Production rate measurements and chart pressure recordings at the wellhead confirmed uniform flow line pulsations.

- Flowline pressure was satisfactorily stabilized.

- The results can help in the application of jet pump systems with remote or well testing equipment.

Introduction

-The Southern Area was discovered between 1965 and 1970 by Texas Petroleum Company.

- Ecopetrol S.A. assumed administration of the field in 1979.

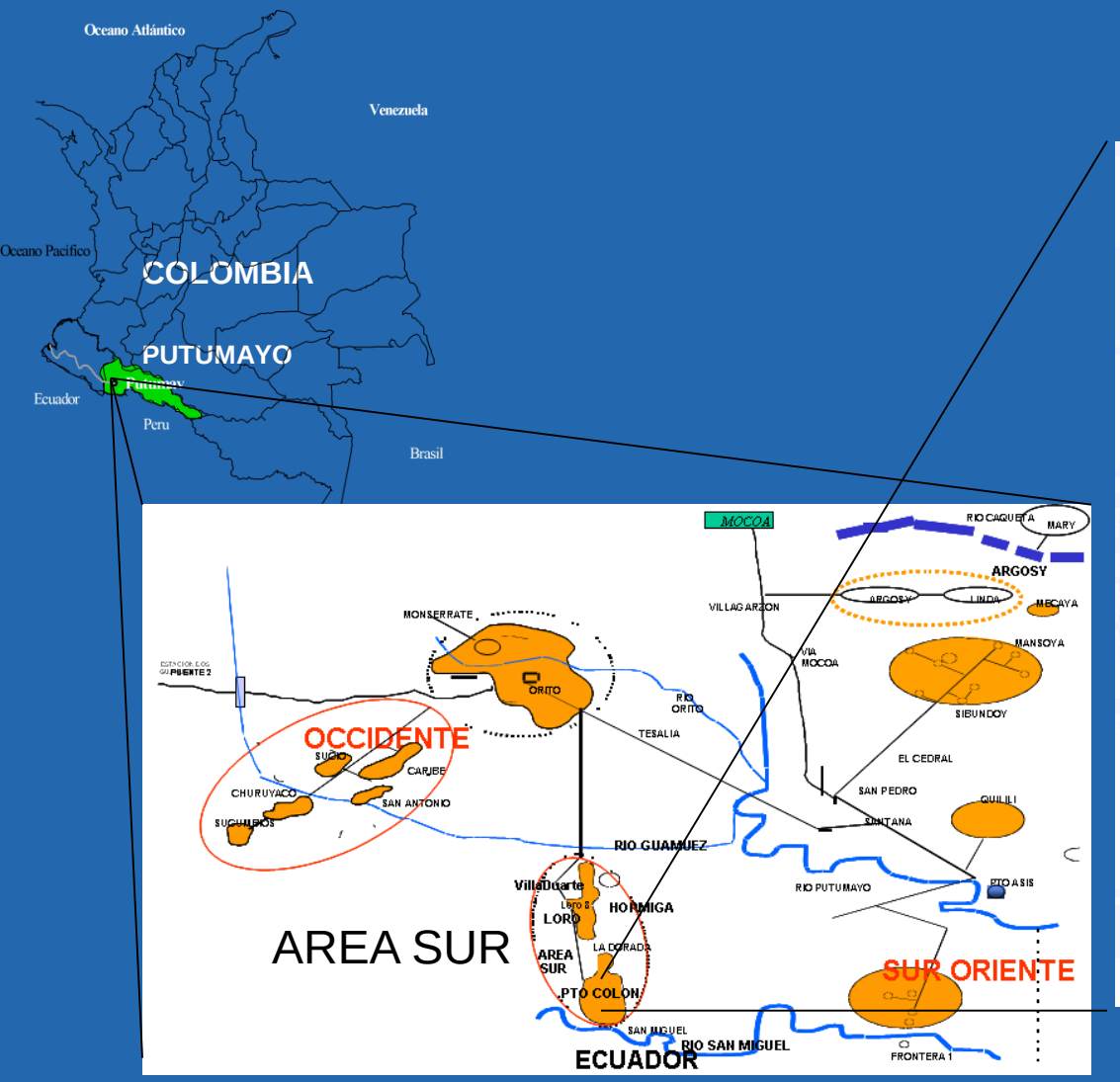
- Well Acae-12D is located in Puerto Colon field.

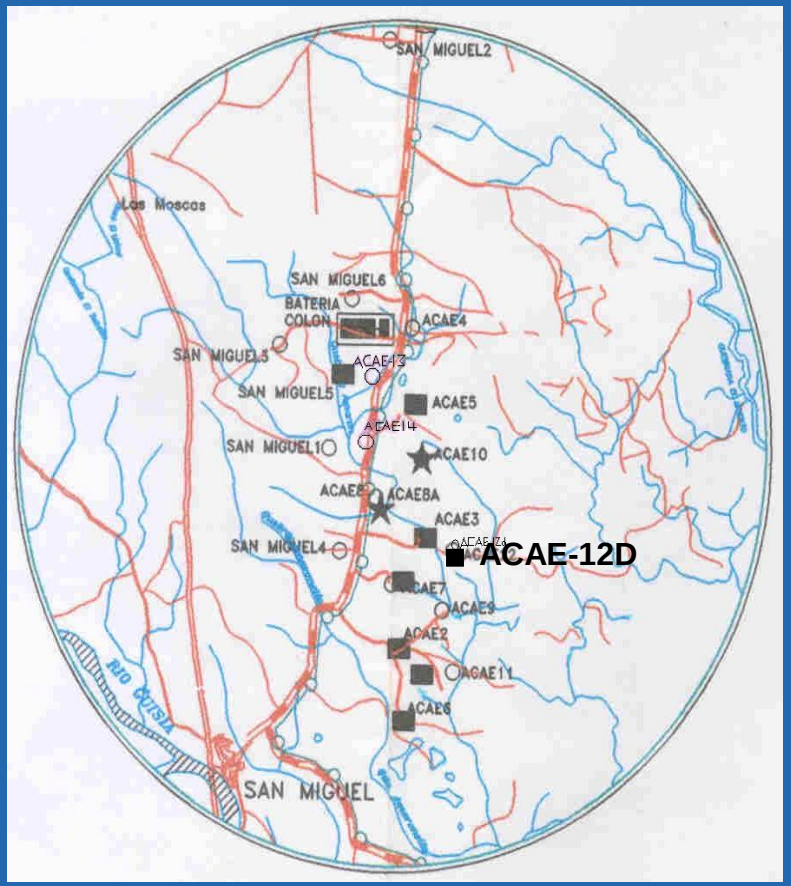
- The Caballos formation is the principal oil crude producing zone and it can be considered to be clean sand.

- The reservoir pressure and gas to oil ratio has been stable during 27 years of production, indicating a strong water drive.

- **Production problems and formation damage in the Colon field have been attributed to:**

  - **Formation of carbonate scale**
  - **Migration of fines**
  - **Asphaltene deposits: during production period.**
  - **Emulsions block: created as early as the completion phase.**





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Caballos Formation Characteristics

Perforations Depth: 10,500 – 10,700 ft ave	Scale: High
CO_2 content: High (60-80%)	Sand: Little
Downhole temperatura: 240 Deg F	Surface temperatura: 85-90 Deg F
Oil Gravity: API 30 Deg	Thickness: 220 ft ave
Type of formation: Clean Sandstone	Permeability: 0.1 – 1200 md
Mechanism drive: Water drive	Porosity: 5% – 16%

Well Acae-12D History

- In December of 2002, Acae-12D was drilled directionally into the Caballos formation using under balanced drilling techniques.

- In open hole drillstem testing the following values were measured:

K = 32-36 md
I.P. = 0.5 y 0.9 bpd/psi
Skin = 0
Qo = 560 y 920 BOPD
BSW = 2% (Water 0%, Sediment 2%)

- The well had been completed for electric submersible lift (ESP), producing negative results.

- A second attempt to produce the well with an ESP resulted in batched production that would have led to premature ESP failure so the ESP was removed.

- A hydraulic lift system was installed in July 2003

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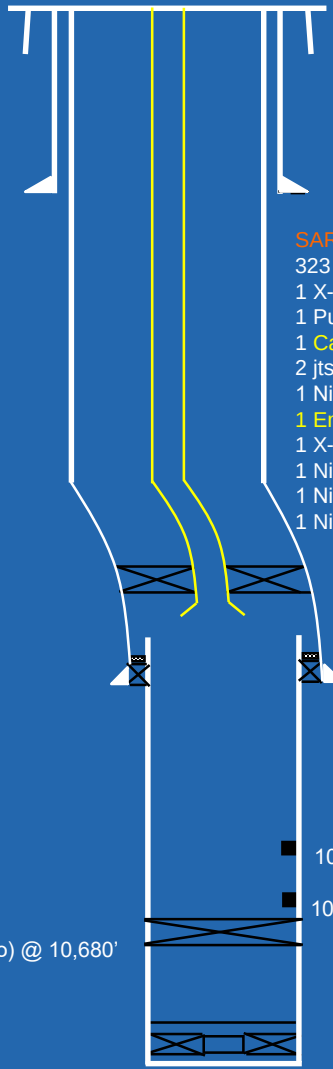
WELL ACAE-12D MECHANICAL STATUS



Revestimiento conductor
Zapato 13-3/8" @ 980'

Revestimiento de Superficie
Zapato 9-5/8" @ 6293'

Revestimiento Intermedio
Zapato 7" @ 10555'

Liner de Producción
Tope Liner 5" @ 10270'

Tipo: **Desviado**
EMR **25 ft**

SARTA DE PRODUCCIÓN
323 jts 3-1/2" EUE, N-80 9.3 #/pie
1 X-Over 3-1/2" X 2-7/8" EUE
1 Pup Joint 2-7/8" X 4 ft
1 Cavidad Tipo A 2-1/2" @ 9984.76 ft
2 jts 2-7/8" EUE N-80 6.5 #/pie
1 Niple NO GO Mod. "R" 2.25
1 Empaque R-3 DG @ 10053.65 ft
1 X-Over 2-3/8" X 2-7/8" EUE
1 Niple ranurado 2-3/8" 24 Orificios
1 Niple NO GO Mod. "R" 1.87
1 Niple campana 2-7/8"

Desviación 15.5°, desde 7650' a 10556'

10,582' - 10,626' (U3)
S.G. 3-3/8", 6 TPP, 60°
(14-06-2003)

10,641' - 10,668' (U2)
S.G. 3-3/8", 6 TPP, 60°
(15-12-2002)
Recañ. SG 3-3/8", 6 TPP, 60°
(14-06-2003)

RBP (Pescado) @ 10,680'

TMD 10835'
TVD 10773'

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Workovers realized:

- **Matrix stimulation and Organic treatment (twice in 2003)**
- **Hydraulic fracturing (twice in 2003) at maximum pressures (12,000 psi). There was no breakdown detected under these conditions.**

Pressure Tests:

- November 2004	**Pwf = 1996 psi** **Q = 562 BFPD**	**PI = 0.238 BFPD/PSI** **BSW = 8%**
- July 2005	**Pwf = 1730 psi** **Q = 328 BFPD**	**PI = 0.125 BFPD/PSI** **BSW = 16%**
- June 2006	**Pwf = 1580 psi** **Q = 265 BFPD**	**PI = 0.095 BFPD/PSI** **BSW = 32%**

PI reduced at 40%
Production reduced at 47%
BSW increased at 300%

Well Data

Pump Depth: 9,984 ft	Casing Pressure: 1,500 psi
Tubing Size: 3-1/2 in	Measured Power Fluid Pressure: 3,650 psi
Casing Size: 7 in	Measured Power Fluid Rate: 1180 bpd
API crude: 30	Nozzle and Throat: 7A
Production Rate: 450 bfpd	Jet Pump size: 2-1/2 in
GOR: 450 scf/bbl	Water cut: 18%
Water specific gravity: 1,02	PI(bpd/psi): 0,0161
Perforating Depth: 10,582 – 10,626 ft, 6 tpp; 10,641 – 10,688 ft, 6 tpp	Flowline pressure: 125 – 195 psi
Bottomhole temperature: 240 Deg F	Bubble point: 1600 psi
Producing Bottomhole Pressure: 1200 psi	Static Bottomhole pressure: 4350 psi

-Well Acae-12D began producing with a jet pump equipped with a 6B combination (An/At of 0.31) During the first three years of operation, production stabilized at 585 BFPD with a 4% BSW.

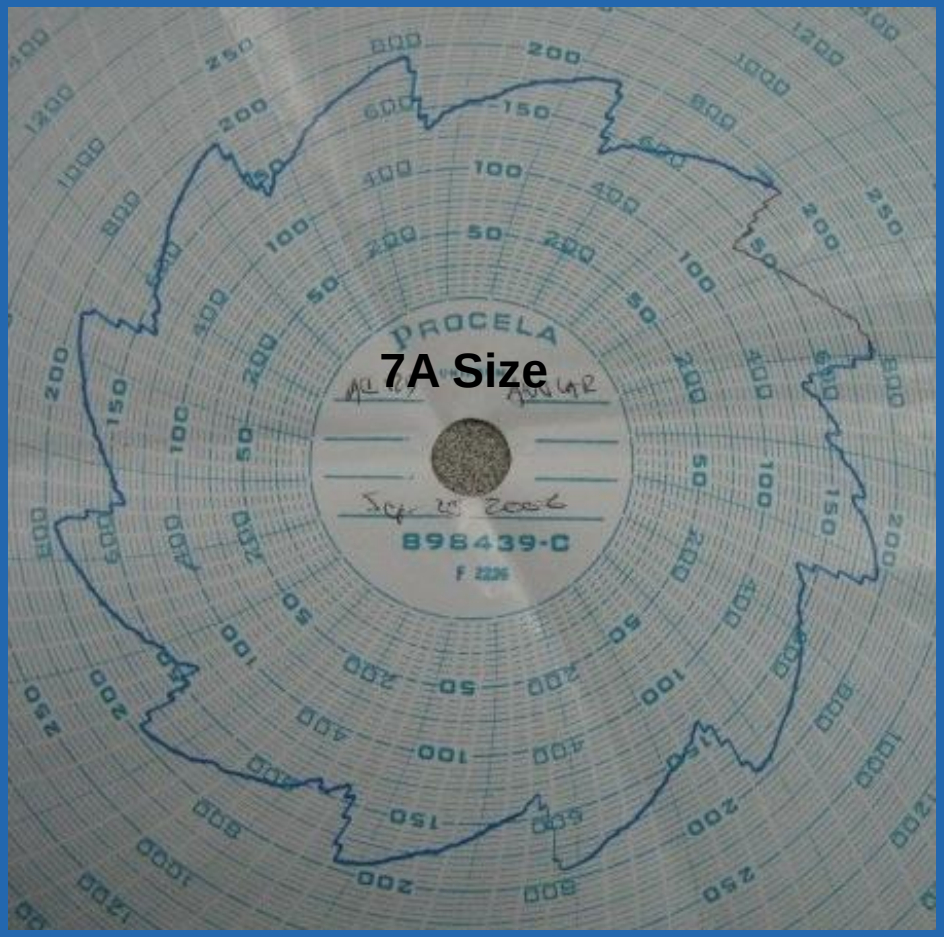
-At the beginning of 2005, the jet pump was equipped with a 7A throat and nozzle combination (An/At = 0.40), production stabilized at 385 BFPD with a 14% BSW.

- In 2006, production began to show continuous unstable flow with flow rates as low as 0 BPH. Remedial cleaning and stimulation had minimal effect.

- These uniform flowline pulsations were similar to those recorded with continuous gas lift.

WELL ACAÉ-12D. AUGUST, 2006 PUMP SIZE: 7-A. THP: 135-195 Psi	
HOUR	**BFPH (Bls)**
1	15
2	115
3	1
4	109
5	74
6	56

	BFPD	**BSW**	**BOPD**	**BWPD**
RETURN	**1480**	**6%**	1391.2	89
INJECTION	**1190**	**0.6%**	1182.9	7
PRODUCTION	290	28.2%	208	82



Well Completion

- In general, wells producing with hydraulic pumps in the area have a high water cut and low gas production.

- The high water cut, low GOR and high dynamic reservoir pressure is best produced with a casing free jet pump well completion.

- The power fluid is crude oil (30° API with 0.5% BSW).

- All produced gas must flow through the jet pump because the tubing is packed off.

- A substantial increase in emulsion content and scale precipitation have been detected when there is more than 2% water in the power oil.

- In order to control scale precipitations, a corrosive chemical is injected at the production facilities and it is carried by the power fluid downhole to mix with well fluids in the jet pump.

Detection and Analysis of Abnormal Condition

- Most wells using jet pumps in Orito have a high water cut and low gas production.

- When a jet pump was installed in a well with higher gas production, the instability in return flow caused confusion.

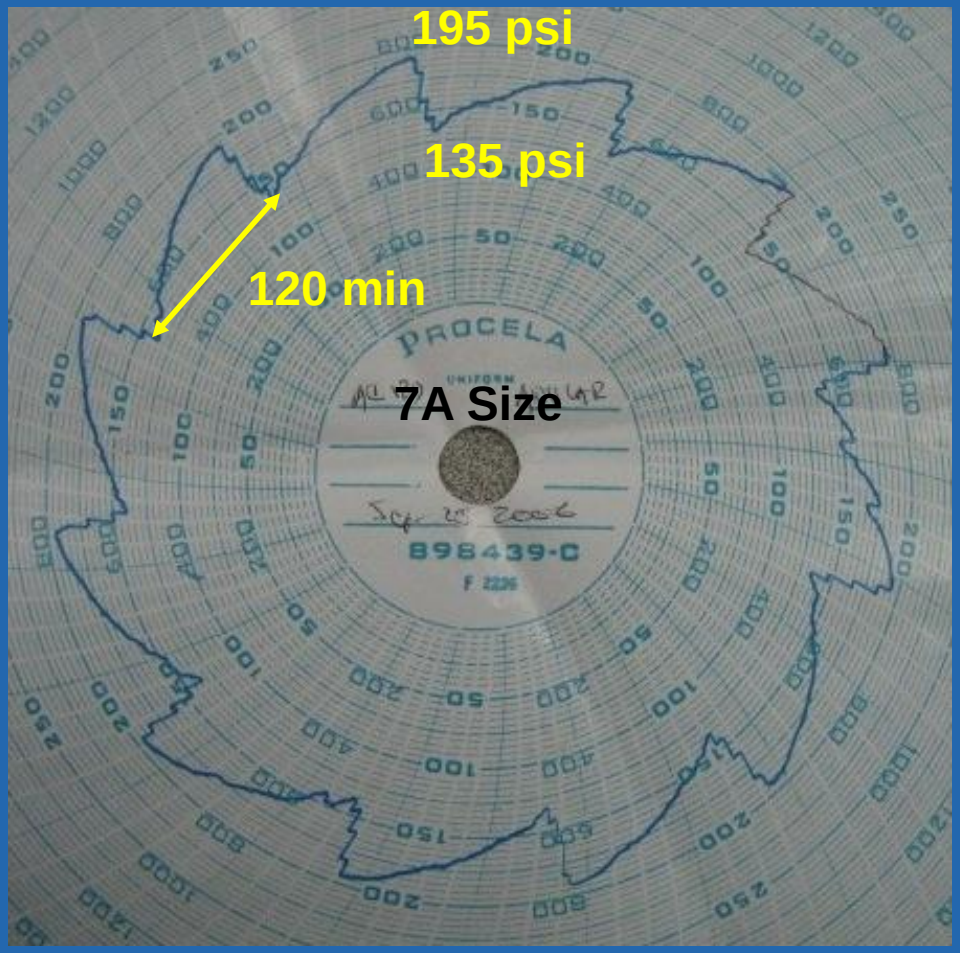
- The characteristics of pulsation recordings in the production flowline confirmed that the formation of gas pockets in vertical gas flow under specific conditions could be uniform.

- These pulsations in the production flow line caused attention, because the well had a history of scale damage.

- A memory gauge was run under the jet pump to monitor producing bottomhole pressure or pump intake pressure.

- The flowline pressure recorder showed repetitive cyclic pulsations similar to those recorded with gas lift valve operation.

- Recordings were measured with 120 minute intervals and variation in tubing pressure (THP) of 135 psi to 195 psi (60 psi differential pressure) as shown in Figure.



-The bottomhole pressure showed pulsations of only 15 – 20 psi. Similar pulsations are seen in most wells so the pulsations in the flow line were not derived from the reservoir.

- The precision in the uniformity of gas bubble amplitude and interval was confirmed with several recordings.

-The next step was to monitor flow line pressure with a pressure recorder.

-The recording showed uniform repetitive pulsations very similar to gas lift valve action.

- The precision of uniform gas pocket pressure amplitude and time intervals caused great confusion.

- The throat and nozzle installed in a jet pump provide a great variety of lift capacity and a variation in the volume of injected high pressure fluid mixed with produced reservoir fluids (oil, water & gas).

- This feature provides a means to vary the gas to liquid ratio (GLR) at the pump discharge which affects vertical multiphase flow conditions.

- This characteristic was used to influence the pulsations measured at the flowline.

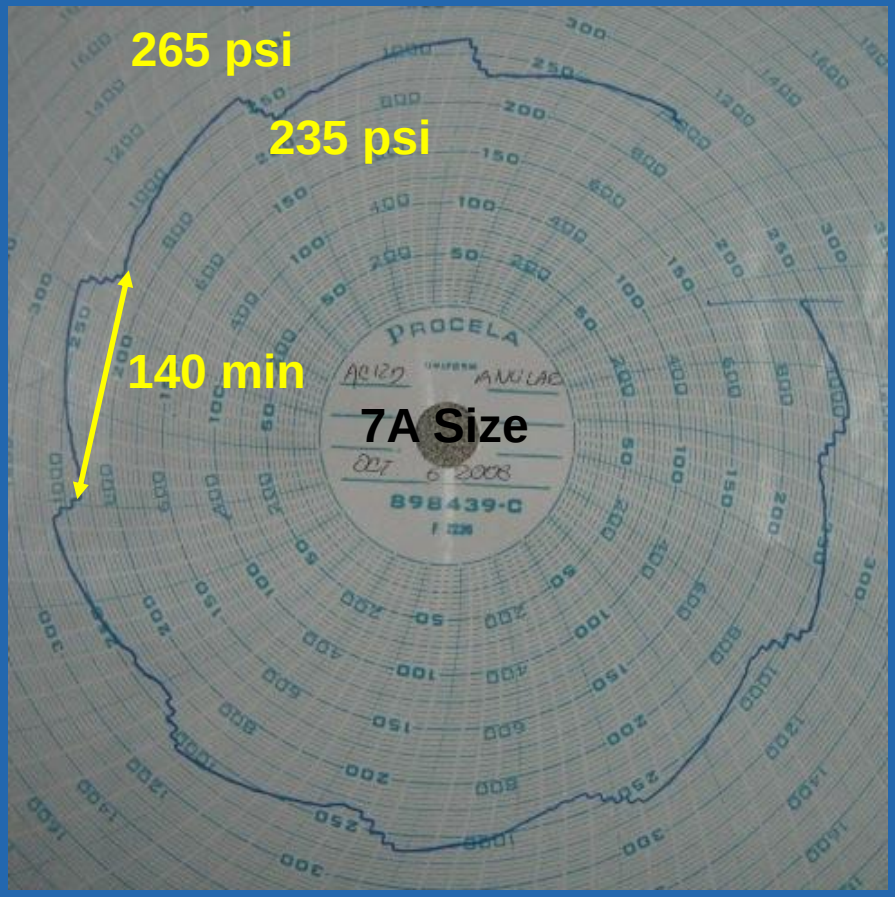
Field test


Upper Valve
Lateral Valve
Master Valve
Power Fluid flowline
Jim pull
Pressure Register
Return flowline

Test number 1

-A valve was choked (60%) on the flowline to apply a backpressure at the wellhead of 100 psi.

- A pressure recorder showed pressure oscillations of 140 minute intervals between 235 psi and 265 psi (pressure differential of 30 psi).

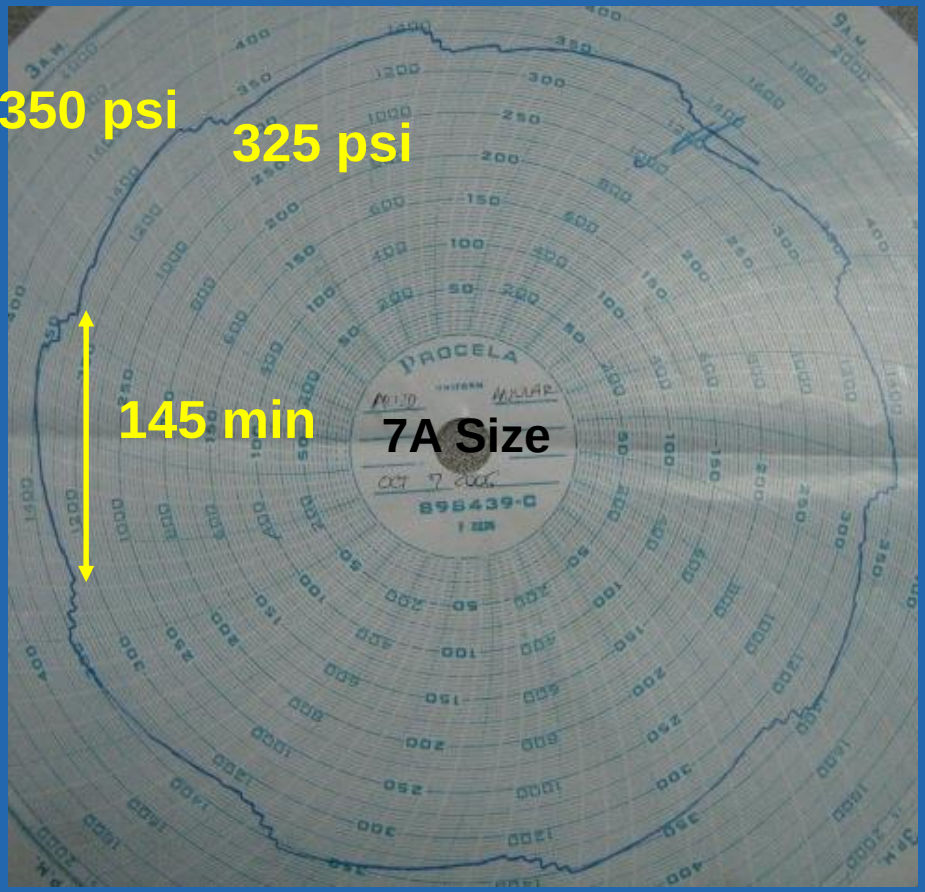


WELL ACAÉ-12D. OCTOBER 6, 2006 PUMP SIZE: 7-A. CHP: 235-265 Psi	
HOUR	**BFPH (Bls)**
1	116
2	7
3	120
4	2
5	122
6	6

	BFPD	BSW	BOPD	BWPD
RETURN	**1492**	**7%**	1388	104
INJECTION	**1195**	**0.5%**	1189	6
PRODUCTION	297	33.2%	199	98

-After 24 hours the flowline backpressure was increased by another 85 psi. Valve was choked at 75%.

- The pressure recorder showed casing head pressure (CHP) between 325 psi and 350 psi (pressure differential of 25 psi) with oscillations of 145 minutes.



WELL ACAÉ-12D. OCTOBER 7, 2006 PUMP SIZE: 7-A. CHP: 325-350 Psi	
HOUR	**BFPH (Bls)**
1	65
2	4
3	133
4	15
5	45
6	108

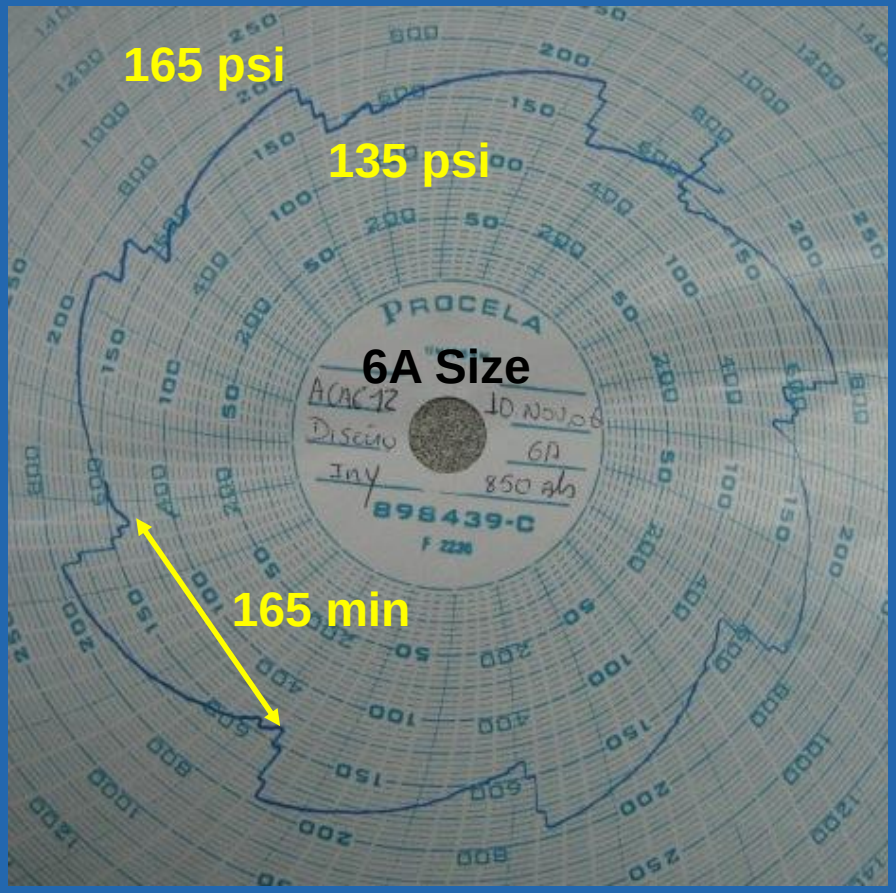
	BFPD	BSW	BOPD	BWPD
RETURN	**1480**	**6%**	1391	89
INJECTION	**1190**	**0.5%**	1184	6
PRODUCTION	290	28.6%	207	83

The production continued in batches very similar to flow rates without backpressure.

Test number 2

-The throat and nozzle combination of the jet pump was changed from a 7A to a 6A.

- The CHP recording indicates an amplitude variation between 135 psi and 195 psi with an oscillation period of 165 minutes.



Results indicate that:

-The differential pressure was the same as with the 7A combination but the oscillation period was increased.

- The pressure drops through a longer time period than with the 7A combination.

Comparison of previous performance of this well with a jet pump equipped with a 7A combination to that obtained with a 6A combination shows that increasing throat and nozzle combination the oscillation period was reduced.

WELL ACAÉ-12D. NOVEMBER, 2006 PUMP SIZE: 6-A. CHP: 135-195 Psi	
HOUR	**BFPH (Bls)**
1	3
2	5
3	127
4	0
5	14
6	115

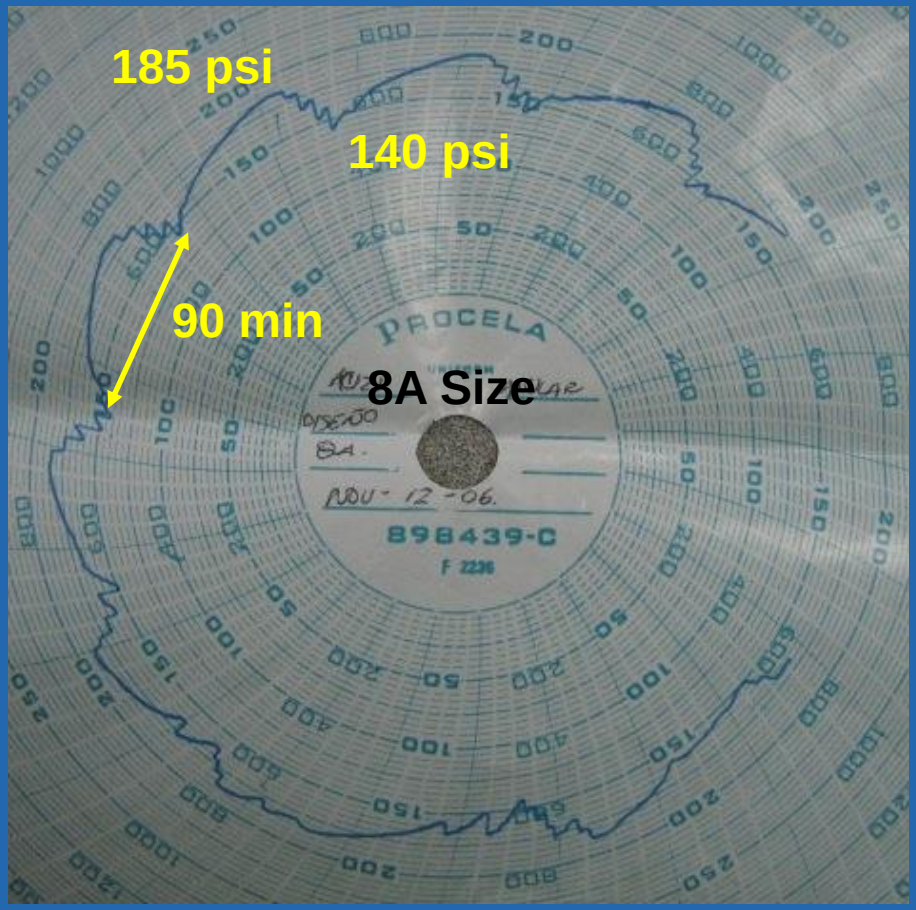
	BFPD	**BSW**	**BOPD**	**BWPD**
RETURN	**1056**	**7.5%**	977	79
INJECTION	**850**	**0.6%**	845	5
PRODUCTION	206	36.0%	132	74

The production was still monitored in batches very similar to flow rates without backpressure.

Test number 3

-The throat and nozzle combination was changed to an 8A with no backpressure on the well.

-The amplitude of the pressure varied between 140 psi and 185 psi with periods of oscillation of 90 minutes.

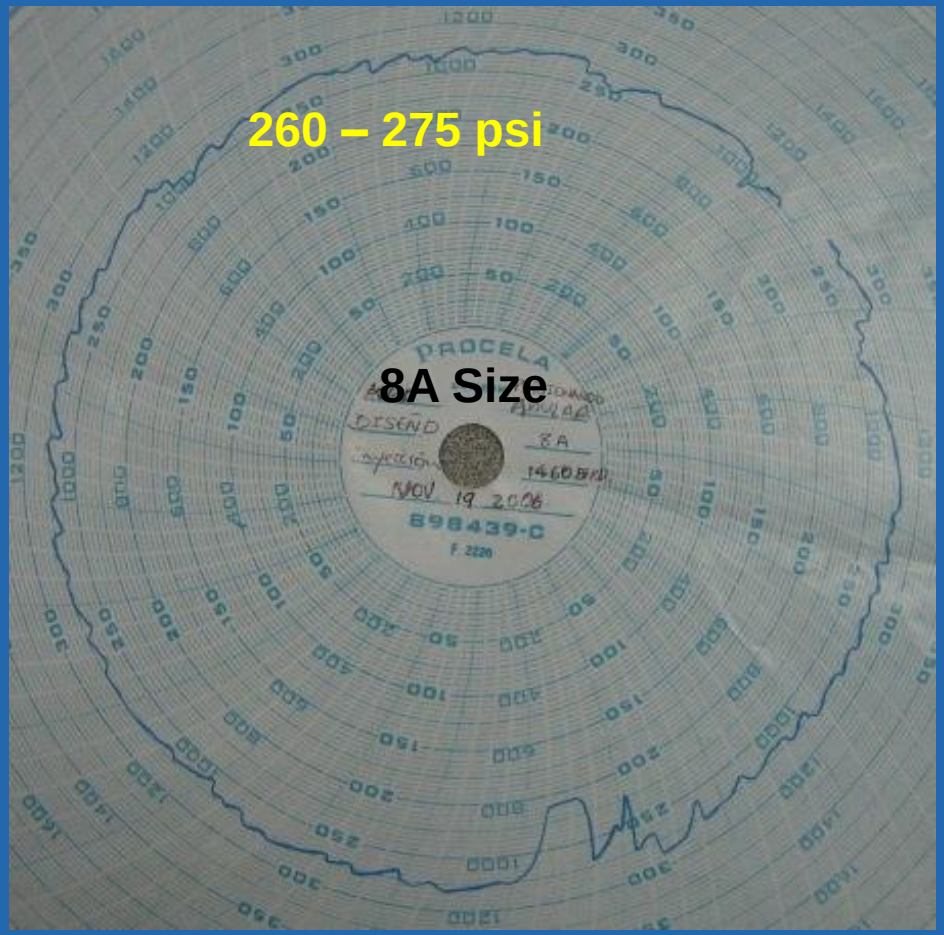


WELL ACAÉ-12D. NOVEMBER, 2006 PUMP SIZE: 8-A. CHP: 140-185 Psi	
HOUR	**BFPH (Bls)**
1	113
2	16
3	137
4	41
5	126
6	8

	BFPD	BSW	BOPD	BWPD
RETURN	1764	7%	1640.5	123
INJECTION	1460	0.6%	1451.2	9
PRODUCTION	304	37.7%	189	115

- Maintaining the same 8A combination, a backpressure of 100 psi was applied over the normal flowline pressure.

- Stable flow was obtained with pressure amplitude variations as low as 15 psi.



WELL ACAÉ-12D. NOVEMBER, 2006 PUMP SIZE: 8-A. CHP: 260-275 Psi	
HOUR	**BFPH (Bls)**
1	33
2	129
3	22
4	117
5	41
6	122

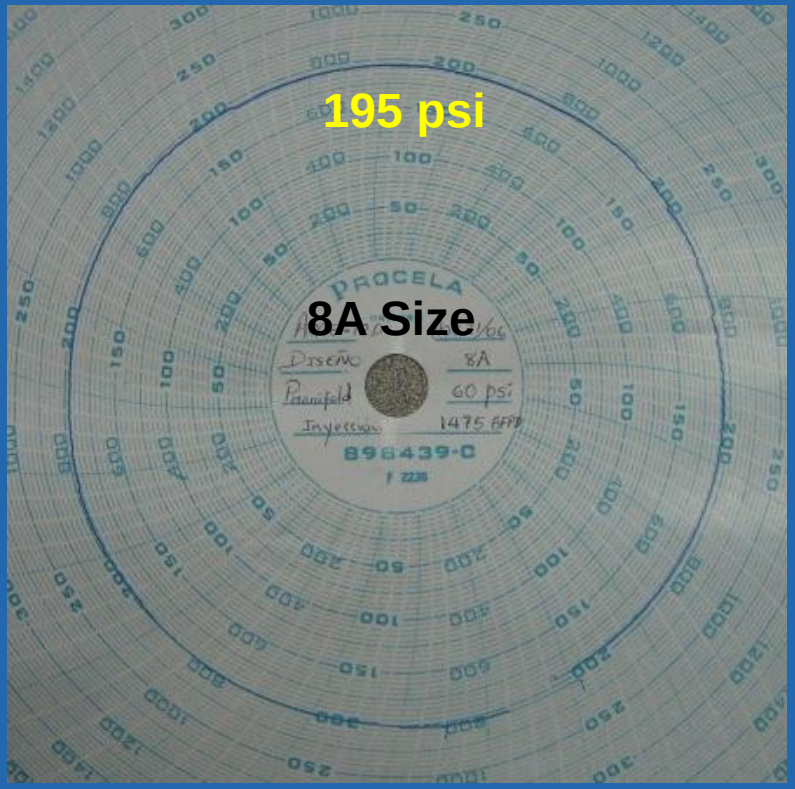
	BFPD	BSW	BOPD	BWPD
RETURN	1856	7%	1726.1	130
INJECTION	1460	0.5%	1452.7	7
PRODUCTION	396	31.0%	273	123

The production performance was still unstable

-Considering stabilization of the pressure upstream with the 8A combination, the final test was to change the choke valve location.

- The well was then choked at the production manifold with 28 psi to 53 psi.

- Results indicate that the wellhead pressure stabilized at 195 psi and the measured production flow rates also stabilized between 72 BFPH and 82 BFPH.



WELL ACAÉ-12D. NOVEMBER, 2006 PUMP SIZE: 8-A. CHP: 195 Psi	
HOUR	**BFPH (Bls)**
1	82
2	80
3	78
4	77
5	81
6	72

	BFPD	BSW	BOPD	BWPD
RETURN	**1880**	**7%**	1748	132
INJECTION	**1475**	**0.5%**	1468	7
PRODUCTION	405	30.7%	281	124

TEST SUMMARY				
TEST	**CHP (Psi)**	**T (Min)**	**PRODUCTION (Bls)**	**REMARKS**
0	135 - 195	120	15 - 115 - 1 - 109 - 74 - 56	Initial production performance. 7A combination.
1	235 - 265	140	116 - 7 - 121 - 2 - 122 - 6	Valve on the flowline was choked to apply a backpressure at the wellhead. CHP was increased at 100 psi. 7A combination.
1.1	325 - 350	145	65 - 4 - 133 - 15 - 45 - 108	Casing head pressure was increased at 185 psi. 7A combination.
2	135 - 195	165	3 - 5 - 127 - 0 - 14 - 115	The throat and nozzle combination of the jet pump was changed from a 7A to a 6A and the backpressure was removed.
3	140 - 185	90	113 - 16 - 137 - 41 - 126 - 8	The throat and nozzle combination was changed to an 8A with no backpressure on the well
3.1	260 - 275	NC	33 - 129 - 22 - 117 - 41 - 122	Valve on the flowline was choked to apply a backpressure at the wellhead. CHP was increased at 100 psi. 8A combination was maintained
3.2	195	NOP	82 - 80 - 78 - 77 - 81 - 72	The final test was to change the choke valve location. The well was then choked at the production manifold. The wellhead pressure stabilized at 195 psi and the measured production flow rates also stabilized.

CHP : CASING HEAD PRESSURE, psi
T : OSCILLATION PERIOD, minutes
NC: No clear
NOP: null oscillation period

Conclusions

1. A viable solution to control the effect of gas pockets flowing up a well is to apply a back pressure on the well at a location downstream of point where the gas pocket can interfere with continuous operation.

2. A change in the jet pump geometry changes the ratio of the more uniform injected power fluid to the multiphase inflow which also affects vertical flow characteristics and potential pulsations at the wellhead.

3. The characteristics of vertical multiphase flow are sufficiently consistent to provide repetitive and uniform pulsations at the wellhead or where ever free gas is released in quantities conducive of bubble formation.