PRODUCTION ENHANCEMENT AND COST REDUCTION OPPORTUNITIES AS IDENTIFIED BY WOOD GROUP ELECTRIC SUBMERSIBLE PUMPS INC.'S SUB MAINTENANCE PROGRAM

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INTRODUCTION

High volume artificial lift through the use of submersible pumps has become common place in the Permian Basin. Many operators have made a significant investment with the use of submersible pumps and, therefore, it is imperative that their submersible pump program attain long runtimes, encounter limited failures, and maintain efficient oil production. To successfully operate submersible pumps, it is critical to have the capability to monitor and evaluate the overall performance on a routine basis utilizing timely, accurate data. One option is the use of Wood Group Electric Submersible Pumps, Inc.'s (WGESP) "Sub Maintenance Program", in which pertinent data is captured and presented in a format where well information can be interpreted so that proactive decisions can be made. Among the opportunities identified by the Sub Maintenance Program are production enhancements, reduction of power costs, reduction of submersible pump failures, and the proper utilization of submersible pump inventory.

THE DEVELOPMENT OF SUBMERSIBLE PUMP MONITORING

WGESP began the early stages of submersible pump monitoring during the 1980's by shooting fluid levels for potential customers to help them decide what kinds of artificial lift methods could most effectively be employed on their wells. In 1994, the "bar was raised" on this process and WGESP began recording monthly fluid level shots and comparing them with production rates. What began, as a very limited service, has now become SmartService. SmartService is a routine, methodical process of viewing a well's performance in relation to the equipment used to produce that well, over time. From the data collected, one can see indications of equipment wear, well decline, and other trends that can potentially impact production, cost, and profitability. This data allows one to make proactive decisions to improve production and/or profitability before catastrophic failures occur. Below are the items of the SmartService report explained (refer to Attachment #1):

HEADER INFORMATION

1. **Company , Lease, Well No, Perforations**
   a. Company name indicates the operator of the well.
   b. Lease name
   c. Well No (number) specifies the well on a given lease.
   d. Perforations indicates the depth at which fluid is entering the wellbore and is used as the pressure datum for calculating pump intake and producing bottom hole. pressure in relationship to the gas-free liquid above the pump calculation.
2. **Casing Size, Tubing Size, Total Joints, Setting Depth**
   a. Casing size indicates the minimum ID in which equipment may be fitted.
   b. Tubing Size indicates the production string. Friction losses may be calculated from this figure.
   c. Total Joints – necessary to get collar count and estimated depth
   d. Setting Depth – the location of the bottom of the motor.
3. **Motor, Pump, Cable Size, Transformers, SB VSD**
   a. Motor indicates the motor rating in HP (horsepower), Volts and Amps
   b. Pump lists the type and number of stages
   c. Cable size lists the wire size and construction (round or flat)
   d. Transformers lists the size and type of transformers used
   e. **SB** VSD (switchboard or variable speed drive) indicates to the user if an across the line starter is used or if a VSD is employed

4. **Base, Run Days, Last Install**
   a. Base indicates that if a motor is re-rated what the original rating of the motor would have been.
   b. Run Days indicates the estimated number of days the unit has operated in this well.
   c. Last install indicates the day in which this unit was last run in the well.
5. **Electrical Operating Conditions**
   a. UL setting – the technician-set underload setting as read on the controller. The relationship of an underload condition to the motor is typically defined by the normal operation of the unit to the wellbore. Initial settings are typically based on 80% of nameplate amps, then are adjusted in accordance to static operating conditions to approximately 80% of normal running amps.
   b. OL setting – the technician-set overload setting as read on the controller. The same relationship as the under load setting. Only for the upper acceptable limits of the motor. Typically initial settings are set at 120% of nameplate amps and then adjusted in accordance with static operating conditions to approximately 120% of normal running amps.
   c. UL % of NP – underload as a percent of nameplate amperage, calculated as the underload setting divided by the nameplate amperage
   d. OL% of NP – overload as a percent of nameplate amperage, calculated as the overload setting divided by the nameplate amperage
   e. Volt % of NP – actual voltage as a percent of nameplate voltage, calculated as the actual voltage per phase divided by the nameplate voltage
   f. Volt Imbalance – calculated as the voltage of each phase divided by the average voltage for all phases.

<u>TABULAR INFORMATION (CURRENT 12 MONTHS)</u>

6. **Test Date –** the month on which the data for this line was taken in the field. For best results, it is recommended that production tests and field data be gathered on the same day, including fluid level shots.
7. **Amp A, Amp B, Amp C –** actual amperage as read in the field with meter usually at the junction box or through the controller. This data can help identify impending cable problems, such as migration, bad insulation on conductors, and loose or bad electrical connections.
8. **Motor Amps –** nameplate or rated amps of the motor.
9. **% Load –** Actual amperage divided by nameplate **amps.** This data allows you to look at possible upside potential and actual rpms on the downhole motor.
10. **Volts AB, Volts BC, Volts CA** – actual readings in the field with meter usually at the junction box or through the controller. This data helps identify phase imbalances, electrical shorts, and ground faults.
11. **Motor Volts** – required voltage to operate the motor at no-load condition.
12. **Hz –** the operating frequency (hertz) of the downhole unit. This is important in determining the calculated production rates. Aids in evaluating upside VSD potential.
13. **BOPD –** Barrels of Oil Per Day furnished by the operator
14. **BWPD –** Barrels of Water Per Day furnished by the operator
15. **MCFD –** One thousand standard cubic feet per day of gas produced furnished by the operator
16. **Ttl Prod. –** total daily production, the sum of the daily oil (13) and water (14) production. For the best results, the fluid level and the production test should be taken on the same day. This information is compared to pump best efficiency point (BEP), as well as actual performance curves.
17. **Best Eff Point (BEP)** – the point at which the pump would operate at peak efficiency – a factor for comparison
18. **GLR –** gas/liquid ratio calculated from the MCFD (15) divided by the total daily production (16)
19. **Oil Cut –** calculated from the oil production (13) divided by the total production (16)
20. **Ttl Liq Above Pump –** reading taken from the Model E Echometer readout and calculated by the Echometer software. This data helps determine upside potential and aids in evaluating pump performance.
21. **GFLAP –** gas-free liquid (fluid level) above pump – reading taken from the Model **E** Echometer readout calcu lated by the Echometer software
22. **Jts To Fluid –** tubing joints to fluid, the distance from the surface to the fluid level as calculated by the Echometer software
23. **PIP –** pump intake pressure as calculated by the Echometer software
24. **TBP –** tubing pressure as indicated on the tubing pressure gauge
25. **CSP –** casing pressure as indicated on the casing pressure gauge
26. **Power Cost –** monthly power cost at a given rate for said power in dollars per kilowatt-hour ($/kWh), as provided by operator. The calculation takes the motor at a given frequency and calculates the % load and power factor on the motor, adds cable losses and controller inefficiencies to determine the estimated cost of operation assuming 24/7 operation.

27. **Comments** – notes to the operator of field observations while taking the readings.
28. **Well History** – a list of pull and runs by date with a brief indication of the reason for the activity. This allows the operator to view the history of the well to better determine a course of action in the future.

GRAPHICAL INFORMATION

29. **Gas Free Fluid Above Pump** – graphed monthly over time, this gives an indication of the relative fluid level with regards to production. More importantly, it is used to indicate graphically the pump intake and producing bottom hole pressure as well as indicating the liquid level above the unit.
30. **Total Production vs Best Eff Point** – graphed monthly over time, it allows the operator to determine if pump is working within its recommended limits.
31. **Graphic of Fluid Level Relative to Setting Depth** – strictly a guide to allow the operator to visualize his well in operation.
32. **Pump Performance Curve** – a catalog curve of the pump in the well with the exact number of stages. This graphic allows the operator to see if the unit has room for improvement or should be resized, replaced, or have the speed changed.

In order to improve your performance, you must first gather data to build a submersible pump database on your wells. Once this is accomplished, you can benchmark your performance against known criteria. WGESP developed a process that gathers pertinent well information and presents it in such a manner that each individual submersible pump can be evaluated. This data provides a snapshot of the downhole unit's operating characteristics as well as production information. Qualified maintenance technicians, who perform a series of checks at each location on a monthly basis, gather the data.

Once the data has been collected, WGESP personnel evaluate it for anomalies. All of the afore-mentioned leading indicators from the sub maintenance report are used to determine whether a submersible pump is operating correctly or whether it becomes a well of concern. This information is often used in combination with other data in monthly failure analysis meetings. For example, the chemical company may be treating a paraffin problem that could have an effect on the pump performance. Armed with **this** data, the operator and WGESP can determine a plan of action for the well. The proactive decisions can range from slowing down a VSD to pulling and resizing the complete unit in order to salvage the existing system.

For best results, **this** report should be viewed monthly to look for changes in production or well conditions, along with changes in the downhole or surface readings. As this data is tracked over time, indications of equipment wear or changing reservoir conditions can be noticed. With experience using this report, an operator can make intelligent decisions about their well and equipment performance, which may lead to improved runtimes, increased production, or reduced costs.

WELLS OF CONCERN OR OPPORTUNITY

If a submersible pump is determined to be operating in such a way that could cause a premature failure or the sub maintenance report shows possible upside potential, the well is identified as a well of concern or opportunity, respectively. These wells are flagged for some type of preventative or proactive work. If a producer operates in the reactive mode and makes no attempts to remedy the situation, they have increased the chances of escalating their operating costs. For example, if the producer knows that a pump is operating outside normal conditions and does not pull the submersible equipment, the motor may be put at risk of failure. More than likely the pump will show signs of irreversible wear, but the motor may still be re-runable. By pulling **this** unit before a failure occurs, the producer does not compound the problem and allow a bad pump to destroy the motor, as might be the case if the unit was run to failure.

APACHE FOCUS AREAS/CASE STUDIES

Apache currently operates approximately 2100 active producers in the Permian Basin, 130 of which are submersible pump installations. The Texaco acquisition in 1995 added significantly to its submersible pump well count and further required a program to effectively monitor the performance of its submersible pumps. These 130 wells produce about **20%** of Apache's total Permian Basin oil production from only 6% of its active producers, with the average submersible pump well producing 38 BOPD and 1400 BWPD. This represents a significant portion of Apache's production, operating costs, and cashflow in the Permian Basin. In 1997, Apache and WGESP implemented a submersible pump maintenance program to monitor Apache's wells on a monthly basis with the objective of reducing the failure frequency and associated failure costs of its submersible pumps, lowering the operating costs of its submersible pumps by using efficient downhole equipment, identifying production enhancement opportunities, and lowering the capital investment required by properly utilizing its submersible pump inventory.

Failure Reduction – When Apache initiated its sub maintenance program in 1997 with WGESP, the failure frequency of its submersible pump wells was 0.6 failures/well/year. By all benchmarks, this failure rate needed to drastically improve considering each submersible pump failure required an investment of $20,000 on average. By the end of 1997, the failure frequency had been reduced to 0.34 failures/well/year (see Attachment #2), resulting in savings of $650,000. Furthermore in 1998, this trend continued downward resulting in a failure frequency of 0.31 by year-end, with additional savings of $85,000. Due to the low oil price environment during 1998, Apache made a conscious decision to use existing submersible pump equipment in inventory, rather than purchase new equipment with its limited capital budget. This approach led partially to a higher failure frequency of 0.52 failures/well/year by year-end 1999, mainly due to re-running marginal equipment. Another factor contributing to this higher failure frequency was related to a hotter-than-normal summer, which led to more power interruptions and caused more downhole failures, especially cable failures. Through October 2000, the failure rate has returned to a more acceptable level of 0.33 failures/well/year.

Apache's prime motivation in instituting a sub maintenance program was to track the submersible pump failure rate and implement proactive measures to reduce the failure rate and associated failure costs. With the exception of 1999, this program has been very successful over the past four (4) years.

Cost Reduction – As determined by information from the sub maintenance report (see Attachment #3) in September 1999, the Good A #19 was producing 19 BOPD, 1020 BWPD, and 20 MCFD with a gas-free fluid level above pump (GFLAP) of 1250 feet. Furthermore, the fluid level had been steadily increasing over the past few months. A review of the production history (see Attachment #4) indicated the well had declined significantly since November 1998 when the well was producing 36 BOPD, 1312 BWPD, and 45 MCFD. It was suspected that pump wear was occumng causing the submersible pump to lose efficiency, as well as the likelihood of calcium carbonate scale buildup, resulting in decreasing total fluid volumes and increasing fluid levels. Also, the sub maintenance report indicated abnormally high power costs as compared to other submersible pump installations in the same field. The submersible pump equipment was pulled in September 1999 and the equipment was sent in for testing. Excessive pump wear was indicated from the teardown. During the workover operations, the Good #19 was stimulated with 1500 gallons of 15% hydrochloric acid. Subsequently, the well was returned to production with a pump design change using 1200 BFPD pumps, resulting in total expenditures of $23,200. The post-workover rates showed flush production of 45 BOPD, 1420 BWPD, and 110 MCFD with a fluid level above pump (FLAP) of 941 feet. Production stabilized at 28 BOPD, 1423 BWPD, and 35 MCFD with a GFLAP of 426 feet four months after the workover, an increase of 9 BOPD and 15 MCFD. Since this well is metered separately for power consumption, the power bills were compared pre- and post-workover to determine if a reduction in power costs was actually seen. The power bill averaged $9,587 per month for the period of January to August 1999, while it averaged $8762 per month for the period of November 1999 to July 2000 after the workover, a reduction of $825 per month or 8.6% was realized (see Attachment #5 & #5a). The post-workover economics for this project realized a payout of 3.1 months while generating incremental net cashflow of $7,400 per month at oil and gas pricing of $24.00/BO and $3.30/MCF.

This type of project shows the real value of a sub maintenance program by tracking well parameters on a monthly basis (production, corresponding fluid levels, power costs), looking for anomalies in the trend data, and identifying project candidates. The Good A #19 project not only resulted in a reduction in operating costs, but also proved to have production upside. Furthermore, with increasing gas prices and electrical deregulation in Texas on the horizon, it is imperative that operators have more power-efficient submersible equipment to help save money on their electric utility bills.

Production Enhancement – The well tests for the North McElroy Unit #4755 (see Attachment #6) had dropped from 140 BOPD and 2129 BWPD in January 1997 to 117 BOPD and 1708 BWPD in April 1997, a total fluid drop of 444 BFPD. In addition, the sub maintenance report (see Attachment #7) indicated that the fluid levels were staying fairly constant at around 300 feet above pump. A check of the submersible pump equipment indicated everything was running normal. Based on the drop in total fluid, it was surmised that the perforations were restricted by calcium carbonate scale. A dump acid job down the casing using 2000 gallons of 15% hydrochloric acid was performed in July 1997 at a cost of $3,400. After leaving the well shut in 1-1/2 hours, the well was returned to production. An immediate response was seen within two days as the well tested at 192 BOPD and 2299 BWPD. The NMU #4755 showed stabilized production of 172 BOPD and 2249 BWPD with a GFLAP of 195 feet in October 1997, an incremental gain of 55 BOPD. The post-workover economics realized a payout of just over four (4) days and incremental net cashflow of $23,900 per month at an oil price of $17.60/BO.

This example really points out that information gathered from the sub maintenance report does not necessarily mean that it is necessary to pull the submersible pump equipment in order to return the well to its normal production trend.

In **this** case, incremental production was realized which displays that the sub maintenance report can be a great tool for identifying production enhancement opportunities.

Inventory Utilization – In March 2000, Apache drilled and completed the North McElroy Unit #3933F. Upon initial completion, well test submersible equipment was run to test the productivity of the well and to properly size the submersible pump. The initial rate of the well was 94 BOPD and 2064 BWPD with a FLAP **of** 738 feet (see Attachment #8). After two weeks, the 3933F was pumped down testing at 61 BOPD and 1727 BWPD. The well was produced long-term with the test submersible pump since this area of the waterflood had previously experienced direct channeling from offset injection wells and it was necessary to determine the stabilized producing characteristics of the well. In August 2000, permanent submersible equipment was run, installing a 30 HP motor and a 1000 BFPD pump. Fortunately, Apache had the submersible pumping equipment in inventory except for the purchase of two (2) new seals. By utilizing its inventory, Apache was able to save $5,250 for the pump, motor, protector, and cable on this submersible pump installation. In October 2000, the NMU #3933F was producing at a stabilized rate of 19 BOPD and 1018 BWPD.

This example really shows the value **of** tracking your submersible pump inventory so that it can be properly utilized in applications as they arise. It should be noted that this equipment is tested when placed in inventory and must meet certain criteria before it is considered re-runable. Furthermore, Apache has extensively used well test submersible equipment to properly size its permanent installations.

CONCLUSIONS

1. For operators of submersible pump installations, it is imperative to have a tool to effectively monitor and bench mark your individual well, field, or area performance. An option is Wood Group Electric Submersible Pumps Inc.'s sub maintenance program.
2. WGESP's sub maintenance program is an effective tool in tracking and improving your submersible pump failure frequency, identifying candidates to reduce power costs, identifying production enhancement opportunities, and properly utilizing your submersible pump inventory.
3. With increasing gas prices and the advent of electrical deregulation in Texas, it is imperative that operators use more-efficient downhole submersible pump equipment to help reduce their power costs.

ACKNOWLEDGMENT

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BIBLIOGRAPHY

1. Echometer Company: "Well Analyzer and TWM Software Operating Manual." (Copyright 1998,1999)

Attachment 1

1 COMPANY: Customer
LEASE: Lease Name
WELL NO: #12
PERFORATIONS: 5342 5456

2 CSG. SIZE: 5 1/2"
TUBING SIZE: 2 3/8"
TOTAL JOINTS: 170
SETTING DEPTH: 5242

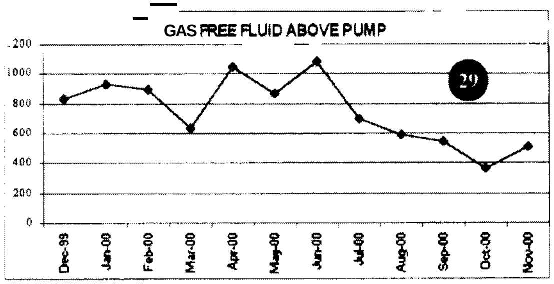
3 MOTOR: 60 HP 1150 / 33
PUMP: 286 STG TD450
CABLE SIZE: 4R
TRANSFORMERS: 3x375
S.B VSD: 480 VSD

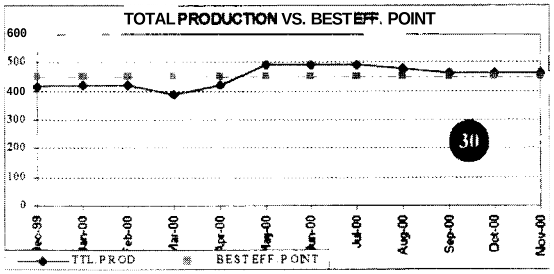
4 BASE
RUN DAYS: 801
LAST INSTALL: 09/12/1998

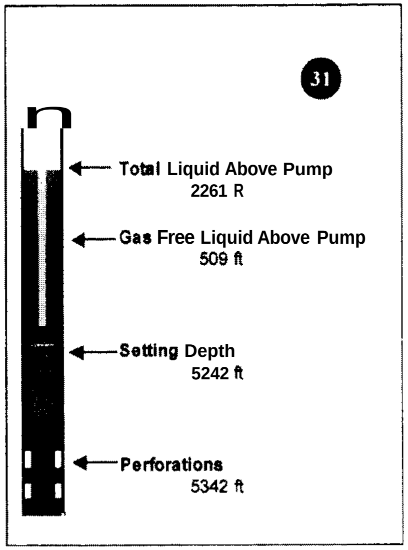
5 Electrical Operating Conditions

					A	B	C
U.L. Setting		U.L. % of KP.	0%	VOLT. % of NP.	102%	102%	102%
O.L. Setting		O.L. % of N.P.	0%	VOLT. Imbalance	1%		

6 TEST DATE	AMP A	7 AMP B	AMP C	8 MOTOR AMPS	9 % LOAD	A-B	10 B-C	C-A	11 MOTOR VOLTS	12 HZ	13 BOPD	14 BWPD	15 MCFD	16 TTL. PROD.	17 BEST EFF. POINT	18 GLR	19 OIL CUT	20 TTL. LIQ. ABOVE PUMP	21 GFLAP	22 JTS TO FLUID	23 PIP	24 TBP	25 CSP	26 POWER COST	27 COMMENTS
Dec-99	36	36	16	33	109%	1050	1053	1061	1150	56.3	113	306	644	419	450	1537	270%	4123	834	35.5	401	150	110	$1,989.92	NDT
Jan-00	36	36	36	33	109%	1050	1053	1061	1150	5b4	115	305	632	420	450	1505	214%	4685	935	17.1	439	150	109	$1,989.92	NDT
Feb-00	36	36	36	33	109%	1050	1053	1061	1150	55	115	305	632	420	450	1505	27.4%	4478	896	239	434	155	117	$1,989.92	NDT
Mar40	23	23	23	33	70%	1096	1097	1095	1150	57.5	106	281	273	381	450	705	27.4%	3153	640	614	355	170	118	$1,321.16	New Chart
Apr-00	23	23	23	33	10%	1117	1115	1109	1150	115	115	305	303	420	450	121	27.4%	4955	1052	8.2	496	170	129	$1,342.46	NDT
May-00	22	22	22	31	61%	1120	1123	1121	1150	58	117	316	465	493	450	943	217%	3714	871	48.3	412	150	99	$1,292.93	New Chart
Jun-00	21	21	22	33	65%	1130	1127	1129	1150	58	117	376	461	493	450	943	137%	4511	1080	221	480	180	98	$1,261.95	Dn 1 Hr 6/20
Jul-00	23	22	22	33	61%	1131	1133	1134	1150	575	101	391	460	494	450	931	20.4%	1423	7U2	58.5	332	162	97	$1,325.78	NDT
Aug-00	22	22	22	33	67%	1143	1137	1131	1150	19	104	376	320	480	450	667	21.7%	2689	581	83	311	160	98	$1,311.76	NDT
Sep-00	23	21	23	33	10%	1143	1138	1133	1150	59	IU2	360	311	461	450	116	22.1%	2519	547	88.1	299	155	99	$1,371.79	NDT
Oct-00	23	23	23	33	70%	1130	1133	1127	1150	57	9%	365	332	463	450	117	21.2%	1807	361	111.6	249	120	98	$1,362.14	NDT
Nov-00	23	22	23	33	69%	1130	1133	1121	1150	59	95	370	329	465	450	108	204%	2261	509	96.1	290	133	100	$1,342.40	NDT



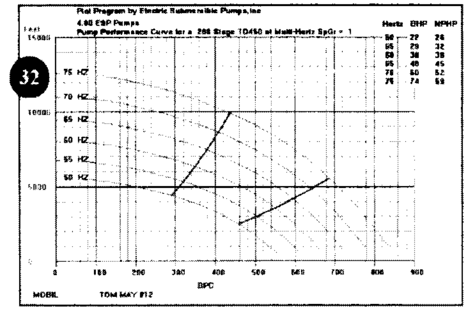




WELL HISTORY

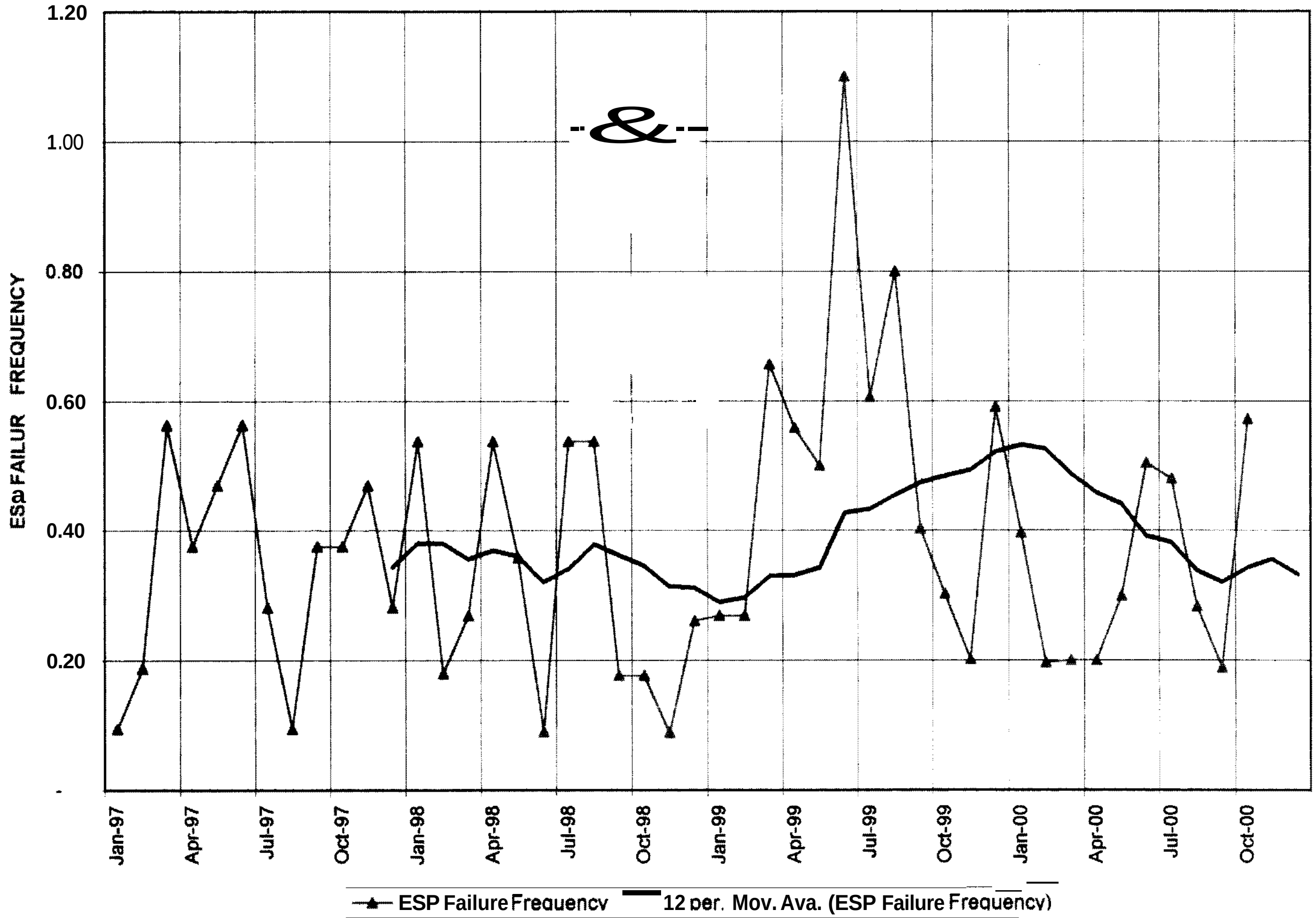
ACTIVITY	DATE	REASON PULLED	DAYS RUN
RUN	04/11/1995	RUN	
PULL	06/04/1996	BURNT MOTOR	420
RUN	06/05/1996	RUN	
PULL	06/06/1998	CABLE GROUNDED	731
RUN	06/09/1998	RUN	
PULL	09/08/1998	LOW PROD/PARAFFIN	91
RUN	09/12/1998	RUN	

28



Attachment 2

APACHE MIDLAND DISTRICT
ESP FAILURE FREQUENCY



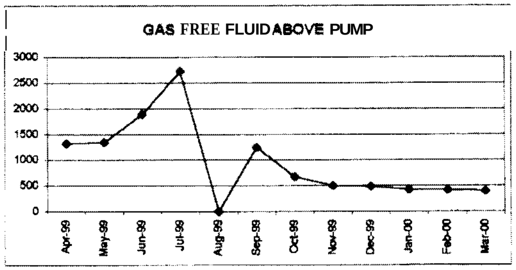
Attachment 3

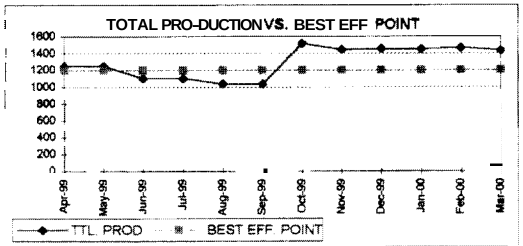
COMPANY:	Apache	CSG. SIZE:	4 1/2"	MOTOR	160 HP 2996 / 40	BASE	
LEASE:	~~TJ Good~~	TUBING SIZE:	2 3/8" 8 rd	PUMP:	450 STG TA1200	RUN DAYS	
WELL NO:	#19	TOTAL JOINTS:	250	CABLE SIZE:	4F	LAST INSTALL:	9/17/99
PERFORATIONS:	7927 8158	SETTING DEPTH:	7829	TRANSFORMERS:	3x100		
				S.B. VSD:	480 VSD		

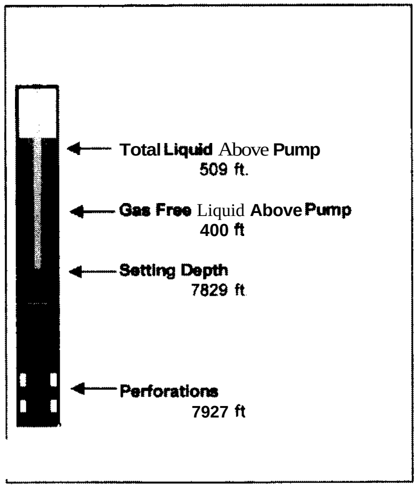
Electrical Operating Conditions

						A	B	C
U.L. Setting		U.L. % of N.P.	0%	VOLT. % of N.P.		87%	67%	87%
O.L. Setting		O.L. % of N.P.	0%	VOLT. Imbalance		0%		

TEST DATE	AMP A	AMP B	AMP C	MOTOR AMPS	% LOAD	A-B	B-C	C-A	MOTOR VOLTS	HZ	BOPD	BWPD	MCFD	TTL. PROD.	BEST EFF. POINT	GLR	OIL CUT	TTL. LIQ. ABOVE PUMP	GFLAP	JTS TO FLUID	PIP	TBP	CSP	POWER COST	COMMENTS
Apr-99	38	37	38	40	94%	3800	3800	3800	2996	73	29	1222	32	1251	1200	26	2.3%	1365	1322	212.2	536	70	67	$9,752.17	NDT
May-99	39	39	40	40	98%	3570	3570	3570	2996	72	29	1222	29	1251	1200	23	2.3%	1671	1351	202.3	545	80	66	$9,567.30	NDT
Jun-99	39	39	40	40	98%	3570	3570	3570	2996	72	24	1081	27	1105	1200	24	2.2%	2086	1866	188.8	716	80	52	$9,567.30	Dn. 4 hrs. Stormy
Jul-99	40	40	39	41	97%	3550	3550	3550	2996	71	24	1081	27	1105	1200	24	2.2%	2724	2724	168.1	1006	80	53	$9,594.33	NDT
Aug-99				40	0%				2996	71	19	1020	20	1039	1200	19	1.8%					80	53	$0.00	Off. Diap. Problems
Sep-99	34	35	33	40	85%	3220	3220	3220	2996	73	19	1020	20	1039	1200	19	1.8%	1611	1250	199.2	513	90	67	$7,458.25	
Oct-99	34	34	34	40	85%	3260	3260	3260	2996	73	33	1485	50	1518	1200	33	2.2%	723	677	228	309	90	58	$7,551.91	Dn. 3 hrs. 10/30
Nov-99	35	35	36	40	88%	3470	3470	3470	2996	73	27	1416	40	1443	1200	28	1.9%	614	503	233.8	262	90	68	$8,353.62	NDT
Dec-99	35	36	36	40	89%	3470	3470	3470	2996	73	28	1427	34	1455	1200	23	1.9%	601	481	231.2	183	70	7	$8,432.42	NDT
Jan-00	36	36	36	40	90%	3470	3470	3470	2996	73	28	1423	35	1451	1200	24	1.9%	426	426	236.1	234	80	64	$8,511.23	NDT
Feb-00	36	36	36	40	90%	3470	3470	3470	2996	73	29	1436	36	1466	1200	25	2.0%	518	415	234.3	244	90	75	$8,511.23	NDT
Mar-00	35	37	36	40	90%	3460	3460	3460	2996	73	28	1403	33	1431	1200	23	2.0%	509	400	235	219	70	69	$8,486.70	NDT

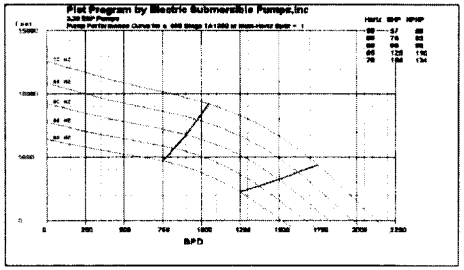




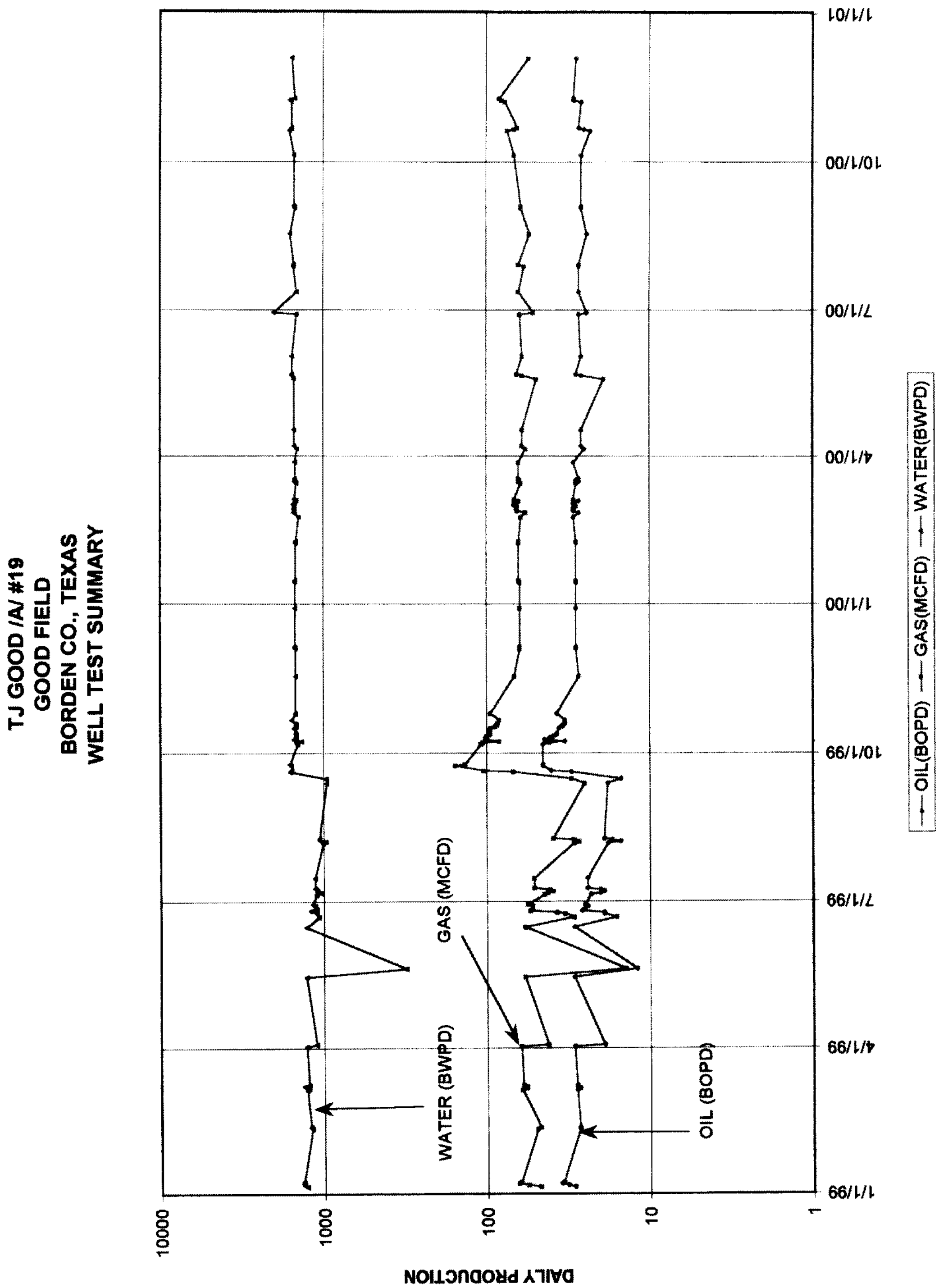


WELL HISTORY

ACTIVITY	DATE	REASON PULLED	DAYS RUN
RUN	7/15/97	RUN	
PULL	3/4/98	WELLWORK	232
RUN	3/6/98	RUN	
PULL	9/29/98	TUBING LEAK	207
RUN	9/30/98	RUN	
PULL	10/1/98	BURNT MOTOR	1
RUN	10/2/98	RUN	
PULL	9/15/99	DOWN-SIZE	348
RUN	9/17/99	RUN	



T.J. GOOD #19

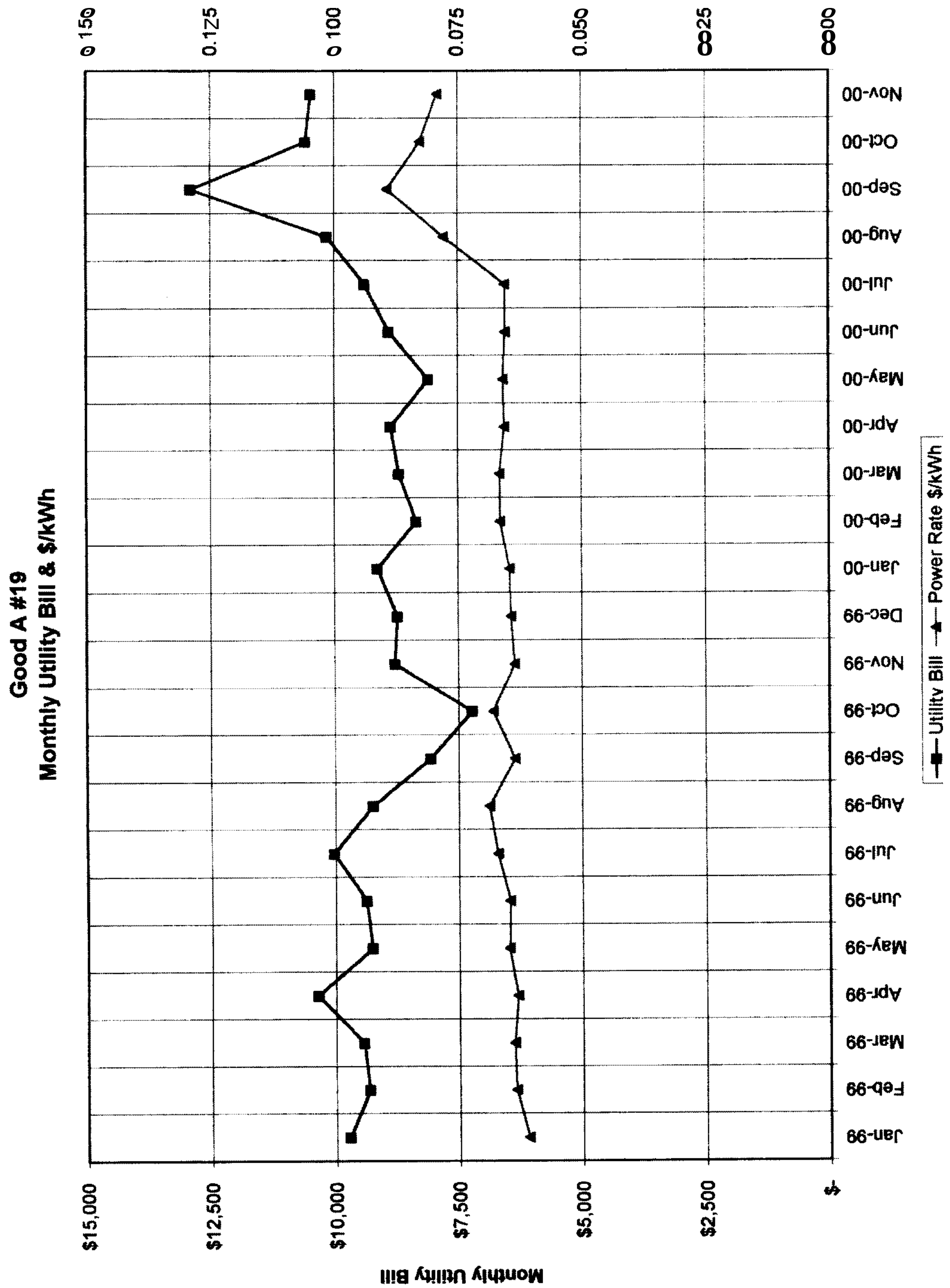


Attachment 4

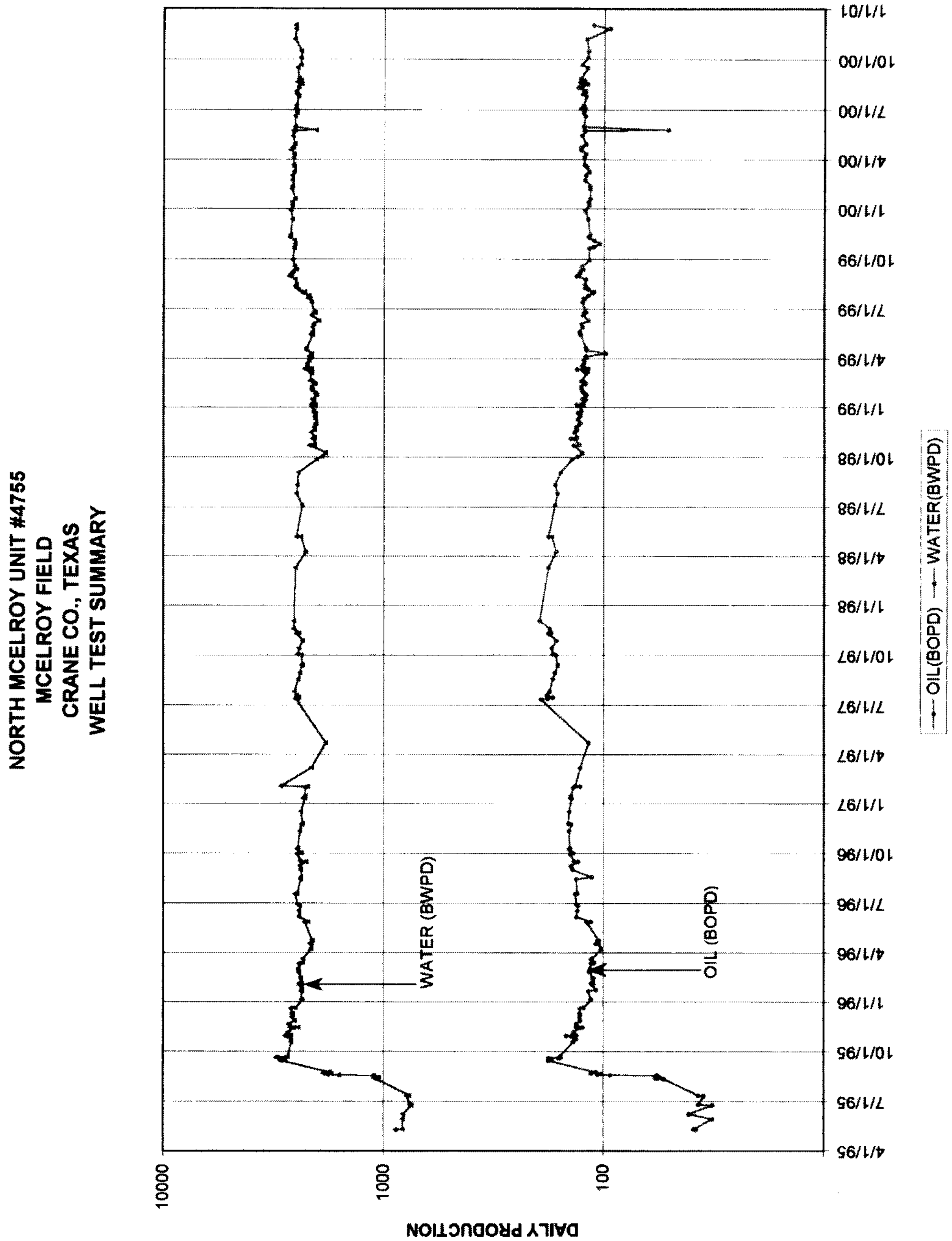
Good A #19 Electric Utility Costs			
Billing Date	**kWh Used**	**Utility Bill**	**Power Rate $/kWh**
Jan-99	159480	$ 9.719.95	0.0609
Feb-99	146640	$ 9.312.56	0.0635
Mar-99	147840	$ 9.431.96	0.0638
Apr-99	164040	$ 10,357.30	0.0631
May-99	142800	$ 9,252.10	0.0648
Jun-99	144960	$ 9,365.22	0.0646
Jul-99	149520	$ 10,025.54	0.0671
Aug-99	134280	$ 9,233.58	0.0688
Sep-99	126720	$ 8,057.08	0.0636
Oct-99	106080	$ 7,214.11	0.0680
Nov-99	138000	$ 8.778.60	0.0636
Dec-99	135840	$ 8.727.84	0.0643
Jan-00	141360	$ 9.124.72	0.0645
Feb-00	125520	$ 8,337.50	0.0664
Mar-00	130680	$ 8.691.65	0.0665
Apr-00	135000	$ 8,850.45	0.0656
May-00	122880	$ 8.087.63	0.0658
Jun-00	135960	$ 8,885.51	0.0654
Jul-00	143280	$ 9.375.00	0.0654
Aug-00	130440	$ 10,143.92	0.0778
Sep-00	144480	$ 12,894.46	0.0892
Oct-00	127920	$ 10,568.17	0.0826
Nov-00	132360	$ 10,465.80	0.0791
Jan-Aug 99 Avg	**148,695**	**$ 9,587.28**	**0.0645**
Nov 99-Jul 00 Avg	**134,280**	**$ 8,762.10**	**0.0653**
Savinas	**14.415**	$ **825.18**	**0.0572**

Note: **Well site is metered separately, thus reflecting kWh and electric costs as determined by Cap Rock Electric**

Attachment 5



Attachment 5A



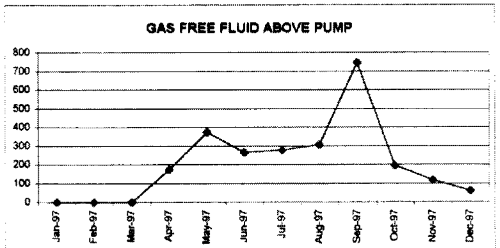
Attachment 6

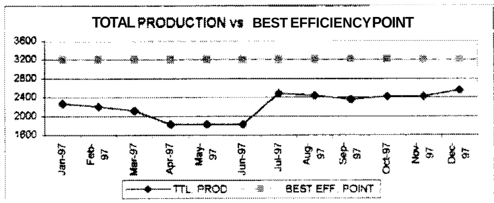
COMPANY:	Apache	CSG. SUE:	6 5/8"	MOTOR	125 HP 2525 / 32	BASE	
LEASE	North McElroy	TUBINGSUE:	2 3/8"	PUMP:	67 STG GN2200	RUN DAYS:	637
WELL NO:	#4755	TOTAL JOINTS:	85 / 2895	CABLE SUE:	#6	LAST INSTALL:	3/18/99
PERFORATIONS:	P7M 2938	PUMP INTAKE:	2908	TRANSFORMERS:	3 X 50		
				S.B. VSD:	2500 V SB		

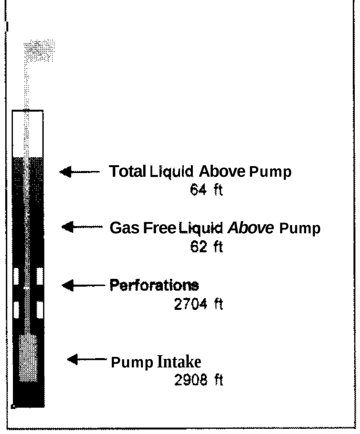
Electrical Operating Conditions

					A	B	C
U.L. Setting	19	U.L. % of N.P.	59%	VOLT. % of N.P.	97%	97%	97%
O.L. Setting	27	O.L. % of N.P.	84%	VOLT. Imbalance	0%		

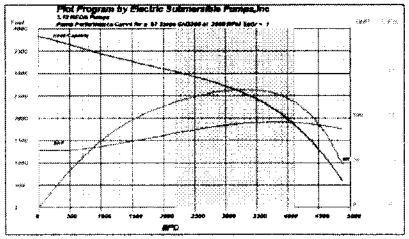
TEST DATE	AMP A	AMP B	AMP C	MOTOR AMPS	% LOAD	A-B	B-C	C-A	MOTOR VOLTS	HZ	BOPD	BWPD	MCFD	TTL. PROD.	BEST EFF. POINT	GLR	OIL CUT	TTL. LIQ. ABOVE PUMP	GFLAP	JTS TO FLUID	PIP	TBP	CSP	POWER COST	COMMENTS
Jan-97											140	2129	0	2269	3200	0	6.2%								
Feb-97											127	2076	0	2203	3200	0	5.8%								
Mar-97											127	1995	0	2122	3200	0	6.0%								
Apr-97	22	24	22	32	71%	2500	2500	2500	2525	60	117	1708	0	1825	3200	0	6.4%	182	174	66.1	108	130	13	$1,781.95	NDT
May-97	22	24	22	32	71%	2400	2400	2400	2525	60	117	1708	0	1825	3200	0	6.4%	379	373	79.9	171	180	15	$1,710.67	NDT
Jun-97	20	24	24	32	71%	2500	2600	2500	2525	60	117	1708	0	1825	3200	0	6.4%	265	265	83.5	110	100	14	$1,781.95	NDT
Jul-97	20	24	24	32	71%	2500	2500	2500	2525	60	192	2299	0	2491	3200	0	7.7%	297	278	74.9	112	150	12	$1,781.95	NDT
Aug-97	22	26	26	32	77%	2500	2500	2500	2525	60	170	2267	0	2437	3200	0	7.0%	356	306	74.7	128	200	18	$1,939.18	NDT
Sep-97	27	28	28	32	86%	2500	2500	2500	2525	60	161	2195	0	2356	3200	0	6.8%	746	746	62.1	274	200	9	$2,175.03	NDT
Oct-97	26	26	26	32	81%	2600	2600	2600	2525	60	172	2249	0	2421	3200	0	7.1%	198	195	77.7	94	190	21	$2,125.76	NDT
Nov-97	26	26	26	32	81%	2600	2600	2600	2525	60	173	2244	0	2417	3200	0	7.2%	119	117	80	97	140	22	$2,125.76	NDT
Dec-97	26	26	26	32	81%	2600	2600	2600	2525	60	195	2356	0	2551	3200	0	7.6%	64	62	61.6	95	131	22	$2,125.76	NDT





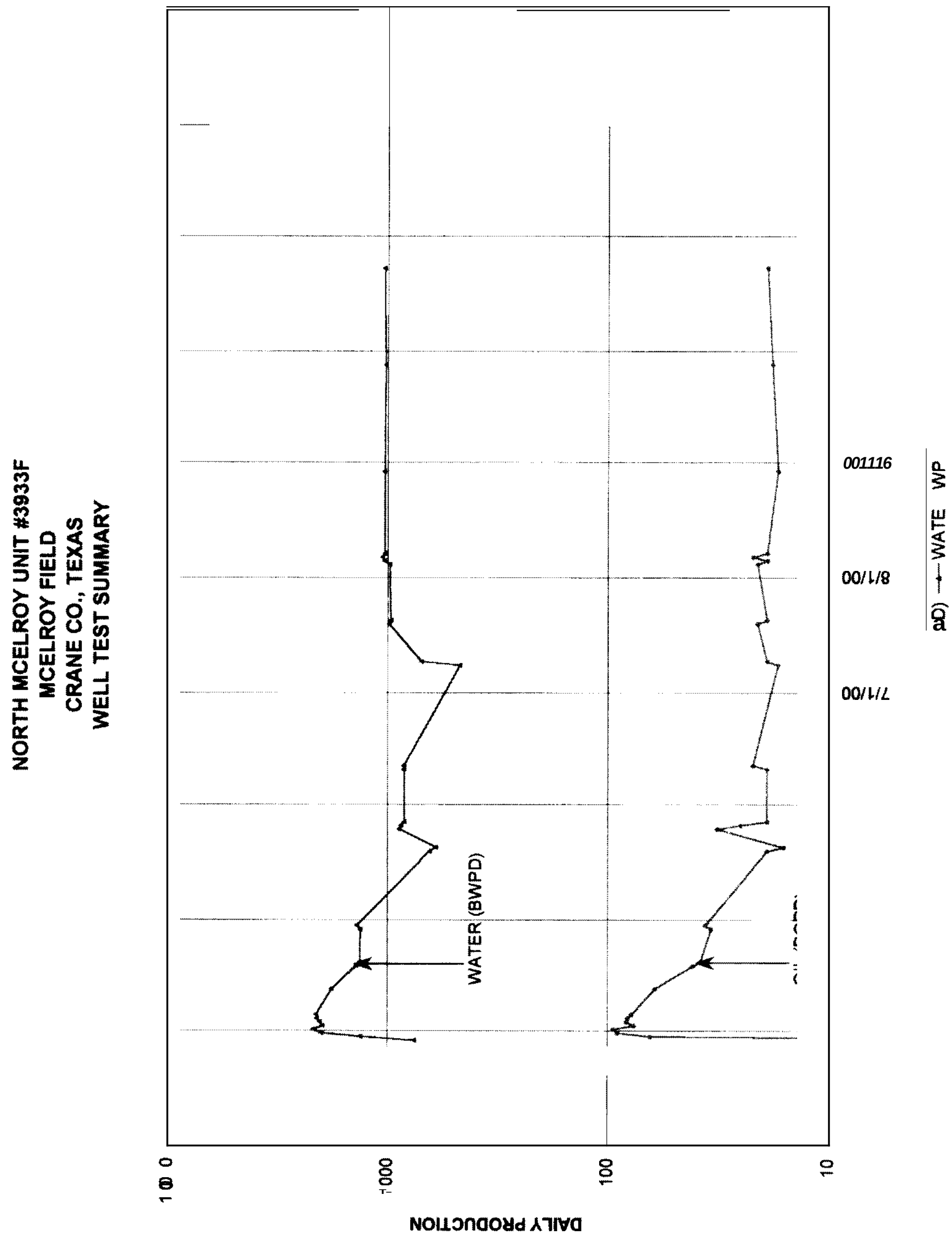


ACTIVITY	DATE	REASON PULLED	DAYS RUN
PULL	5/21/98		4755
RUN	5/25/98	RUN	



NORTH McELROY #4755

Attachment 7



Attachment 8