11/30/04 1 of 2

FIELD TESTING & OPTIMIZATION OF CO_2/SAND FRACTURING TECHNOLOGY

Final Report

County	State	Date	Wells	Stage	Grp #
Crockett	TX	12/95	3	6	1A
Crockett	TX	12/95	6	3	1B
San Juan	NM	01/96	3	3	2
Phillips	MT	07/98	3	3	5
Blaine	MT	09/02	4	4	7
		Total	16	19	

By

RAYMOND L. MAZZA

Period of Performance
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Work Performed Under Contract No.: Contract #DE-AC21-94MC31199
"Field Testing & Optimization of CO_2/Sand Fracturing Technology"

For:
U. S. Department of Energy
National Energy Technology Laboratory
Morgantown, West Virginia

By
Petroleum Consulting Services
Canton, Ohio

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DISCLAIMER

EXECUTIVE SUMMARY

These contract efforts involved the demonstration of a unique liquid free stimulation technology which was, at the beginning of these efforts, in 1993 unavailable in the U.S. The process had been developed, and patented in Canada in 1981, and held promise for stimulating liquid sensitive reservoirs in the U.S. The technology differs from that conventionally used in that liquid carbon dioxide (CO_2), instead of water is the base fluid. The CO_2 is pumped as a liquid and then vaporizes at reservoir conditions, and because no other liquids or chemicals are used, a liquid free fracture is created. The process requires a specialized closed system blender to mix the liquid CO_2 with proppant under pressure.

These efforts were funded to consist of up to 21 cost-shared stimulation events. Because of the vagaries of CO_2 supplies, service company support and operator interest only 19 stimulation events were performed in Montana, New Mexico, and Texas.

County	State	Date	Wells	Stages	Grp #
Crockett	TX	12/95	3	6	1A
Crockett	TX	12/95	6	3	1B
San Juan	NM	01/96	3	3	2
Phillips	MT	07/98	3	3	5
Blaine	MT	09/02	4	4	7
		Total	16	19	

Final Reports have been prepared for each of the four demonstration groups, and the specifics of those demonstrations are summarized therein.

Crockett County, Texas

The first demonstrations were in Crockett County in the Canyon sands and consisted of two groups of three wells. The placed proppant volumes with the CO_2/sand process were much lower than the design volumes do in part to reduced pump rates because of pressure limitations. The production responses were poor, and it was concluded that the fracture lengths generated by the liquid CO_2 stimulations were insufficient.

San Juan Co, New Mexico

Three Candidate Wells completed in the Fruitland Coals were stimulated with the CO_2/Sand process and minimal proppant volumes were placed believed to be a result of an unusually large number of perforations. The projected five year cumulative production ranged from the three Candidate Wells ranged from 65.3 to 141.9 MMcf and averaged 91.3 MMcf while that from the six Control Wells ranged between 15.6 and 445.2 MMcf averaging 231.3 MMcf or 2.5 times that from the wells.

These poor responses from the wells stimulated with the CO_2/sand process are unquestionably related to a number of factors regarding the formation characteristics of permeability, and pressure, but to a larger extent to the reduced proppant volumes placed by the liquid-free treatments

Phillips County, Montana

Full proppant volume (40,000 pound) CO_2/sand stimulations were easily executed in three Candidate Wells completed in the Phillips Sand in the Phillips Co, Montana test area, but the production from the Candidate Wells failed to meet those required by the criteria for success.

The twenty-four month cumulative production volumes from the wells stimulated with the liquid-free CO_2/sand process are essentially the same as that from the Control Wells treated with N_2 Foam and utilizing the same 40,000 pound proppant volume, and there is a suspicion that the wells which were stimulated with CO_2/sand are being choked by limited conductivity in the hydraulically created fracture, probably as a consequence of the smaller proppant size used (20/40 vs. 12/20). This is based on the observation of the nearly identical monthly production volumes from all three Candidate Wells. And, also on the production comparisons of twenty nearby wells which utilized larger proppant.

Blaine County, Montana

Full proppant volume CO_2/sand stimulations were successfully pumped in three of four Candidate Wells which were completed in the Eagle Sands. All four Candidate Wells had production improvements which through July, 2004 (22 months following the stimulation) ranged from 3.1 to 54.1 MMcf and averaged 19.5 MMcf. The total incremental improvement is 77.8 MMcf.

One well, Blackwood 06-09, accounted for the majority – 70% (54.1/77.8) of the incremental production increase, and it is the only well which exceeded the success criteria.

SUMMARY

The liquid free CO_2/Sand stimulation technology results in a liquid free propped fracture and is the only known process which provides this benefit. Because the viscosity of CO_2 is low (0.1cp) the fracture lengths are limited, but the benefits of a non-damaging fracture can prove beneficial to liquid sensitive formations especially as the reservoir pressure diminishes.

ABSTRACT

A summary of the demonstrations of a novel liquid-free stimulation process which was performed in four groups of "Candidate Wells" situated in Crockett Co, TX, San Juan Co, NM, Phillips Co, MT, and Blaine Co, MT. The stimulation process which employs carbon dioxide (CO_2) as the working fluid and the production responses were compared with those from wells treated with conventional stimulation technologies, primarily N_2 foam, excepting those in Blaine Co, MT where the reservoir pressure is too low to clean up spent stimulation liquids.

A total of 19 liquid-free CO_2/sand stimulations were performed in 16 wells and the production improvements were generally uneconomic

I. ABSTRACT

A summary of the demonstrations of a novel liquid-free stimulation process which was performed in four groups of "Candidate Wells" situated in Crockett Co, TX, San Juan Co, NM, Phillips Co, MT, and Blaine Co, MT. The stimulation process which employs carbon dioxide (CO_2) as the working fluid and the production responses were compared with those from wells treated with conventional stimulation technologies, primarily N_2 foam, excepting those in Blaine Co, MT where the reservoir pressure is too low to clean up spent stimulation liquids.

A total of 19 liquid-free CO_2/sand stimulations were performed in 16 wells and the production improvements were generally uneconomic

II. INTRODUCTION

The demonstration of a unique liquid-free stimulation treatment technique which utilizes carbon dioxide (CO_2) as the working fluid and which was previously unavailable in the U.S. was initiated and performed in the eastern U.S. under another contract (#DE-AC21-90MC26025 – "Production Verification Tests") and extended under this contract to demonstrations in the western states.

The technology held promise for stimulating liquid-sensitive reservoirs in that the CO_2 is pumped as a liquid to hydraulically create fractures, and then will vaporize at reservoir conditions and flow from the reservoir as a gas, resulting in a liquid-free induced fracture. Additionally, the process which had been developed in Canada utilized specialized equipment to enable proppant to be mixed with and transported by the liquid CO_2 thereby resulting in a propped fracture to prevent it from closing.

These efforts required the cooperation of gas well operators to provide "Candidate Wells" wells for the demonstrations, and in return they received financial cost-shared support for this DOE sponsored program. The operators provided the Candidate Wells, the specifics on nearby "Control Wells", and the production data from the Candidates for five years following the stimulations. The production responses from the Candidate Wells, which were stimulated with the CO_2/Sand process were then compared to that from the conventionally stimulated Control Wells to determine if any advantage would be realized from this process.

These efforts were funded to consist of up to 18 cost-shared stimulation events, another 3 were subsequently added bringing the total to 21 demonstrations.

Difficulties in procuring CO_2, service company dispositions, and a lack of operator interest resulted in only 19 events being executed. The unexpended funds were returned to the DOE. These difficulties would likely have been less of an encumbrance had a service company with a nationwide sales group been involved. The small Appalachian-based service company that provided the blender did not have the resources to provide services in the western U.S. on a regular basis, and there were also reluctances by the larger service companies with pumping equipment in the western U.S. to provide a seamless field experience for the operator.

The contract also specified that each demonstration group of Candidate Wells was to include a minimum of three wells. By design this requirement was to enable the statistical confidence in the results to be elevated.

III. BACKGROUND

The first demonstrations of the CO_2/Sand stimulation process were initiated through a DOE sponsored project and were conducted in eastern Kentucky's Big Sandy gas field in January, 1993. Significant successes resulted in that considerably larger gas volumes were produced from wells which were stimulated with the liquid-free CO_2/Sand stimulation process than from nearby wells which had been hydraulically fractured with other treatment types namely, N_2 gas and especially N_2 foam. The five year per well incremental benefit (two stages) of the production from the CO_2/Sand stimulations resulted in an improvement of 135.4 MMcf over that from N_2 foam stimulations and 110.4 MMcf improvement over N_2 gas stimulations.

Because of these favorable responses the DOE solicited other liquid sensitive reservoirs in the western U.S. to further apply the CO_2/Sand technology. The subject contract and this Report are the results of that solicitation.

IV. IDENTIFICATION AND SELECTION OF CANDIDATE WELLS

There were a total of 15 groups which preliminary information was submitted to the DOE for review and comment. Of those 8 complete Candidate Well packages were upon DOE request further prepared and resubmitted. Five of those well groups were approved for treatment. There were 7 rejected by the DOE, and 3 from which the operator elected not to participate.

Submittals	No
Preliminary Proposals	15
Rejected by DOE	-4
	11
Operator Withdrew	-3
Formal Proposals	8
Rejected by DOE	-3
Executed	5

The DOE approvals of these 5 groups have resulted in 19 Stages (16 wells) being stimulated with the CO2\Sand process with cost shared participation under the subject contract.

Pkg #	Opr	Form	Depth	County	St	DOE ?	#	Stg	Date	Status
1A	UPR	Canyon	6,700	Crockett	TX	Y	3	6	Dec-95	Executed
1B	UPR	Canyon	7,300	Crockett	TX	Y	3	3	Dec-95	Executed
2	Amoco	Fruitland	2,100	San Juan	NM	Y	3	3	Jan-96	Executed
3	Chevron	Wolfcamp	9,500	Terrel	TX		2	2	Aug-97	DOE-Rej
4	Ultra Petr	Lance	12,500	Sublette	WY		3	15	Feb-98	DOE-Rej
5	WBI	Phillips	2,200	Phillips	MT	Y	3	3	May-98	Executed
6	WBI	Eagle	1,400	Fallon	MT		3	3	May-98	OP-Withdrew
7	Ocean Engy	Eagle	1,400	Blaine	MT	Y	4	4	Sep-02	Executed
	Evergreen	Niobrara	1,600	Yuma	CO		2	2		DOE-Rej
	Thermo CoGn	Niobrara	1,600	Cheyene	KS		2	2		DOE-Rej
	Amoco	Mary Lee	2,200	Tuscaloosa	AL		8	8		OP-Withdrew
	Cedar Ridge	Fruitland	2,200	LaPlata	CO		3	3		OP-Withdrew
	Chandler	Mancos	2,400	Blanco	CO		3	3		DOE-Rej
	Crescendo				TX		1	1		DOE-Rej
	Burlington	Lewis Sh	3,800	San Juan	NM		6	6		DOE-Rej

V. METHODOLOGY

The evaluation of the CO_2/sand stimulations was done through the comparison of the five-year cumulative produced gas volumes from the Candidate Wells which were stimulated with CO_2/sand with that from nearby Control Wells which had been stimulated with other processes. These other stimulation processes included nitrogen (N_2) foam, and gelled water processes.

The wells with the larger projected five-year cumulative produced gas volumes, after the flush production was removed, were considered to be superior.

A. Mathematical Analog of Production Data

The procedure to remove the flush production volumes utilizes a fit of a mathematic equation of the later time production, and then utilizing that relationship to extrapolate the early production if the flush production rates had not occurred.

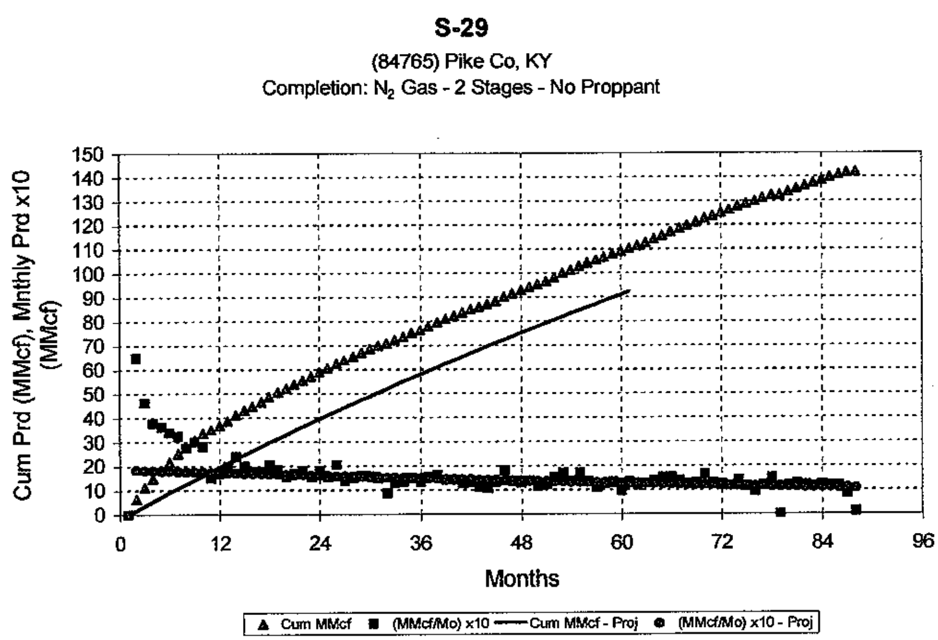
There were some instances where the flush production volumes were minimal which reinforces the benefit of being able to more acutely focus in on the reservoir characteristics through the elimination of this bias. This process can also provide a significant benefit when there is missing production data.

C. Missing Data

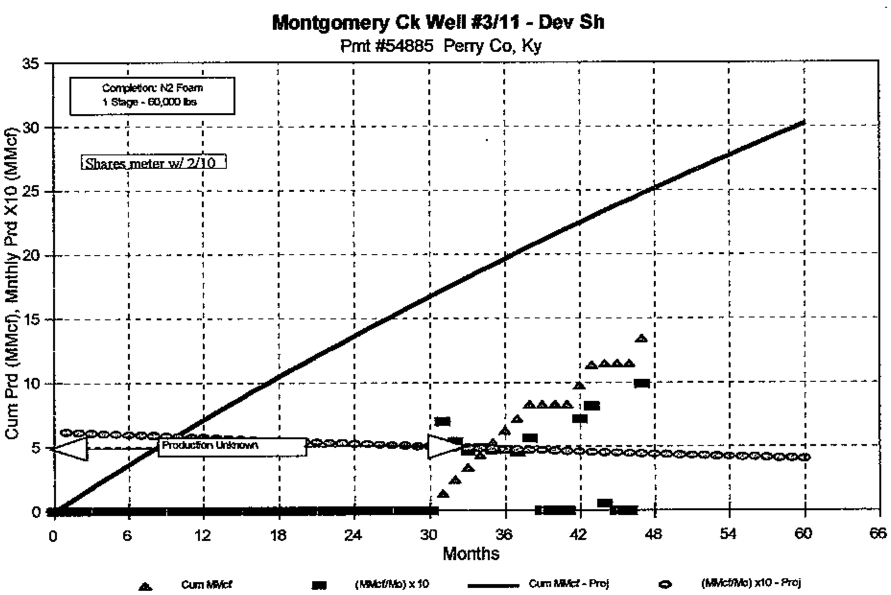
This process can also provide a significant benefit when there is missing production data.

D. Examples

The following examples demonstrate the procedure utilized to remove the gas produced during the flush production period which in this case lasted approximately 13 months. The actual produced gas volume was 41 MMcf while the projected volume was 23 MMcf or a difference of 18 MMcf. The projected five year cumulative production is 92 MMcf whereas the actual production volume measured was 110 MMcf.



In the second example there was no production data available for the first 29 months, additionally the available data included two shut in periods which are followed by flush production periods. By utilizing a mathematic fit of the steady state production data a realistic projection of the production resulted. The limited data set was then utilized, and the bias resulting from the flush production periods following the shut in periods was removed.



In removing the effects of the flush production volume a more realistic assessment of the response to the different stimulation types resulted. The production plots for each well including the actual and projected values are included in this report.

VI. CO_2/SAND STIMULATION TREATMENTS

A. Design

A stimulation design was prepared and presented to the operators. Because of prior successes in placing full blender volumes, it was concluded that the first effort would be to attempt a maximum quantity of 47,500 lbs. This recommended stimulation design was;

PROPPANT FLUID SCHEDULE					
	Cum (bbl)	Stage (bbl)	Proppant (ppg)	Proppant (lb)	Cum (lb)
Stage					
Hole Fill (Liquid CO_2)	53	53		0	0
Pad (Liquid CO_2)	190	115		0	2310
Start Sand	55	55	1.0	2,310	2,310
Increase Sand	110	55	2.0	4,620	6,930
Increase Sand	165	55	3.0	6,930	13,860
Increase Sand	383	218	3.5	32,046	45,906
Flush (Liquid CO_2)	615	44		0	45,906
	Total	615			

TREATMENT FLUID REQUIREMENTS						
	Hole +	Prop	Flush	Tot Pumped	Bottom	Total
Liquid $_{CO2}$ (bbl)	168	403	44	615	10	625
CO_2 (T)						120
Nitrogen (Mscf)						74

VII. DOE APPROVALS

A formal submittal package was prepared for each of the 7 groups and submitted to the DOE for consideration. After their review and some additional information provided, some of the treatments were approved for the cost-shared demonstration.

VIII. FIELD ACTIVITIES

A. Preparations

Preparations for the field activities included perforating the Candidate Wells and the placement of two 60 to 80 ton CO_2 storage vessels on the location and then filling them with liquid CO_2 during the 24 hour period prior to the treatment.

B. Stimulations

A summary of the perforation, stimulation specifics (volumes, rates, pressures) for all of the Candidate Wells is presented in the Final Report for each group.

IX. IS THE PROPOSED RESERVOIR LIKELY TO BENEFIT FROM THE CO_2/SAND TECHNOLOGY?

Because the CO_2/sand stimulation utilizes CO_2 as the working fluid which is pumped as a liquid and subsequently vaporizes at formation temperature and flows from the reservoir as a gas, no liquid remains behind and the gas can flow from the reservoir unimpeded.

X. OPERATORS

The following questions were considered by each of the operators, and each of the test areas provided or afforded:

A. An interest in CO_2/Sand technology?

B. An adequate test opportunity?

C. A presently active drilling program?

D. A future for successful results? Is the operator likely to continue implementing this technology without DOE cost support?

E. An interest in DOE cost-supported participation?

F. Share production data for five years?

G. Letter of Intent

The operator provided a letter of intent agreeing to:

1. Provide legitimate well opportunities for three mutually agreed upon wells,
2. Provide acceptable background information on the nearby wells including the drilling, completion, and production specifics,
3. Bear the normal additional expenses of cement bond logging, perforating, bull dozers, and other normally occurring expenses associated with stimulation events,
4. Participate in the demonstration project and the anticipated treatments specifics, and
5. Provide the production and flowing pressure information from the Candidate Wells for five years.

XI. TEST AREAS

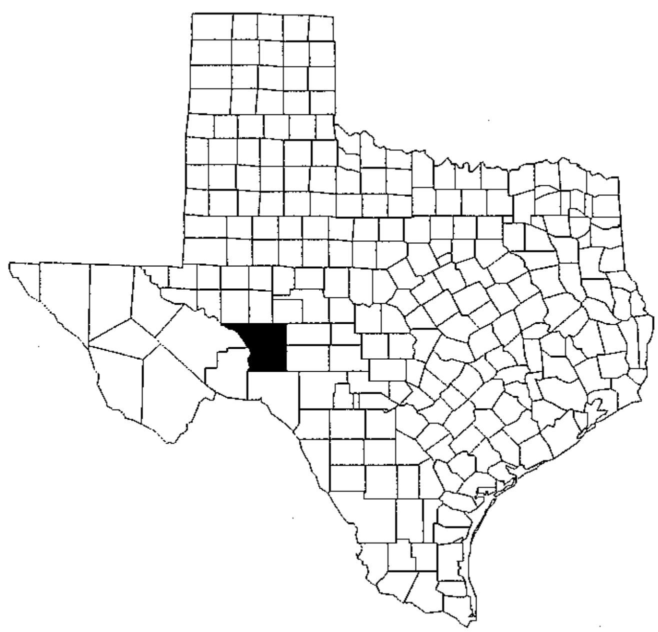
A. TEST AREA #1 – Crockett Co, Tx – Package #'s 1A & 1B - 9 Stages / 6 Wells

1. Location

Two Test Areas:

1A – Block NG (Montgomery)

1B - Block MM (Hoover-Hatton)



The first demonstrations under the contract were executed in December, 1995 in two characteristically separate groups each containing three wells.

They are situated in the Val Verde Basin of South Texas in Crockett County near the town of Ozona, and produced from the Canyon Sands at depths ranging from 6,428 to 7,420 feet. The production is primarily gas with minimal condensate - approximately one barrel per million cubic feet of gas (1 bbl/MMcf).

The major differences between the two areas, 1A-Block NG (Montgomery) and 1-BBlock MM (Hoover-Hatton) are that the Canyon Sand interval in Block NG contains an increased pay thickness.

2. Operator

The operator was at the time was Union Pacific Resources (UPR) formerly Union Pacific Resources Corporation (UPRC). UPR has since been purchased by Anadarko Petroleum.

3. Reservoir

The target formations are the Canyon Sands which are complex deep water turbodite deposits that contain numerous gas productive members. They are approximately 1,200 feet thick and contain eight individual sand members which are designated A (shallowest) through H, and some may not be present in offset wells. Consequently the perforated intervals vary and ranged in depth from 6,428 to 7,420 feet in the Candidate Wells. Because of this variation, the per-well reserves can vary considerably within an area and range from 0.2 to 1.2 billion cubic feet (Bcf) of gas.

4. Producing Horizon

The Canyon Sands are known for the capillary retention of liquids and these Candidate Wells were considered to be good candidates for demonstrating the liquid-free CO_2/Sand technology. Historically, a number of these sand members were stimulated and the production co-mingled.

The unique combination of the zones within individual wells complicated attempts at fracture analysis. Numerous studies performed by UPR were unsuccessful in identifying a relationship between treatment size (proppant volume) and the post-fracture well performance.

5. Test Area #1A - Block NG (Montgomery) - Two Stage Completions

Block NG occupies approximately four sections and contained seventeen active wells. The three Candidate Wells were completed in the C (Lower) & E (Middle) Sands and were stimulated with two stage CO_2/sand treatments.

The reservoir pressure was about 50% of the original (when they were drilled on 320 acre spacing) and the estimated ultimate recoveries (EUR's) generally range between 1,500 and 4,500 MMcf.

a. Permeability

The permeability's range from 0.001 to in excess of 0.10 millidarcy.

b. Reservoir Pressure and Temperature

The reservoir temperatures and pressures were:

Well	Press (psig)	Temp (°F)	Total Depth (ft)
Hoover 7C-7	760*	155	7,585**
Hatton 8C-4	760*	181	7,613
Hatton 13-14	760*	182	7,515
* Calculated			
** The total depths are deeper than the lowermost perforation; for instance the deepest perforation in the Hoover 7C-7 well is 7,420 feet			

A review of the phase behavior at these temperatures and pressures confirmed that the CO_2 would vaporize under these conditions. A phase diagram for each well group was prepared and is not included here, but accompanies the report for that group

c. Sensitivity to Stimulation Liquids

The wells in these areas require some time to clean up following the liquid based stimulations and appeared to be excellent candidate opportunities for this technology.

The Canyon Sands are known for the capillary retention of liquids, and each of the two groups of three Candidate Wells were considered to be viable opportunities for demonstrating the liquid-free CO_2/Sand technology. Primarily, because of the suspicion that formation damage was resulting from the formations sensitivity to stimulation liquids, and also through the interest that UPR indicated in the process and their ability to effectively evaluate the results through their in-house knowledge and large data set.

d. Control Wells

There were 7 Control Wells:

	Well	Pmt # 42-105-xxxx	5 Yr Prod (MMcf)
1	Montgomery 02-17	10786	1,695.2
2	Montgomery 01-17	10785	1,100.2
3	Montgomery 03-15	30742	814.4
4	Montgomery 07-16	31725	662.0
5	Montgomery 04-15	31021	510.9
6	Montgomery 05-18	31727	370.8
7	Montgomery 01-16	10101	65.8

e. Candidate Wells

There were three Candidate Wells. They were infill wells which were drilled on 40 acre spacing and the initial plan was to stimulate them with conventional stimulations with an anticipated performance of approximately 70% that of the 80 acre wells drilled previously.

	Well	Pmt # 42-105-xxxx	5 Yr Prod (MMcf)
1	Montgomery 13-18	36988	26.7
2	Montgomery 12-18	36989	120.8
3	Montgomery 14-18	36987	153.6

(1) Stimulation #1 - Candidate Well # 1 – Montgomery 13-18 (36988)

(a) Stage #1

A total of 24,200 pounds of sand were placed in zone, in the first stage. The maximum acceptance sand concentrations were unknown and screened out as the 3.0 ppg sand concentration started into the formation.

(b) Stage #2

The treatment consisted of 26,100 lbs of proppant were pumped at an average rate and pressure of 40.0 barrels per minute and 5,230 psi respectively. It screened out with 20,800 pounds of proppant in zone for an average in zone proppant concentration of 1.37 ppg.

(2) Stimulation #2 - Candidate Well #2 – Montgomery 12-18 (36989)

(a) Stage #1

The first stage was stimulated with 25,000 lbs of proppant pumped at an average rate and pressure of 40.0 barrels per minute. The treatment screened out with 10,400 pounds of proppant in zone for an average in zone proppant concentration of 0.73 ppg. The treatment was compromised by significant CO_2 leaks around the piston rod packings. The leakage was estimated to be at least five (5) barrels per minute. The resultant injection rate after the leaks would be 35 barrels per minute and is believed to be the explanation for the screen out.

(b) Stage #2

The second stage treatment consisted of 20,700 lbs of proppant pumped at an average rate and pressure of 43.0 barrels per minute. The in zone proppant volume was estimated 19,800 pounds.

(3) Stimulation #3 - Candidate Well #3 -- Montgomery 14-18 (36987)

(a) Stage #1

11,500 lbs of proppant were pumped at an average rate and pressure of 39.6 barrels per minute and 5,590 psi respectively. The treatment had to be temporarily discontinued after pumping 39 barrels of CO_2 because of a leaking wellhead isolation tool. The pumping was halted and the pressure bled from the well head to replace a leaking element. The pumping was resumed after approximately two hours. The in zone proppant volume was an estimated 8,100 pounds.

(b) Stage #2

The treatment consisted of 13,700 lbs of proppant pumped at an average rate and pressure of 43.0 barrels per minute and 5,100 psi respectively. The in zone proppant volume was estimated 12,900 pounds.

(4) Stimulation Summary

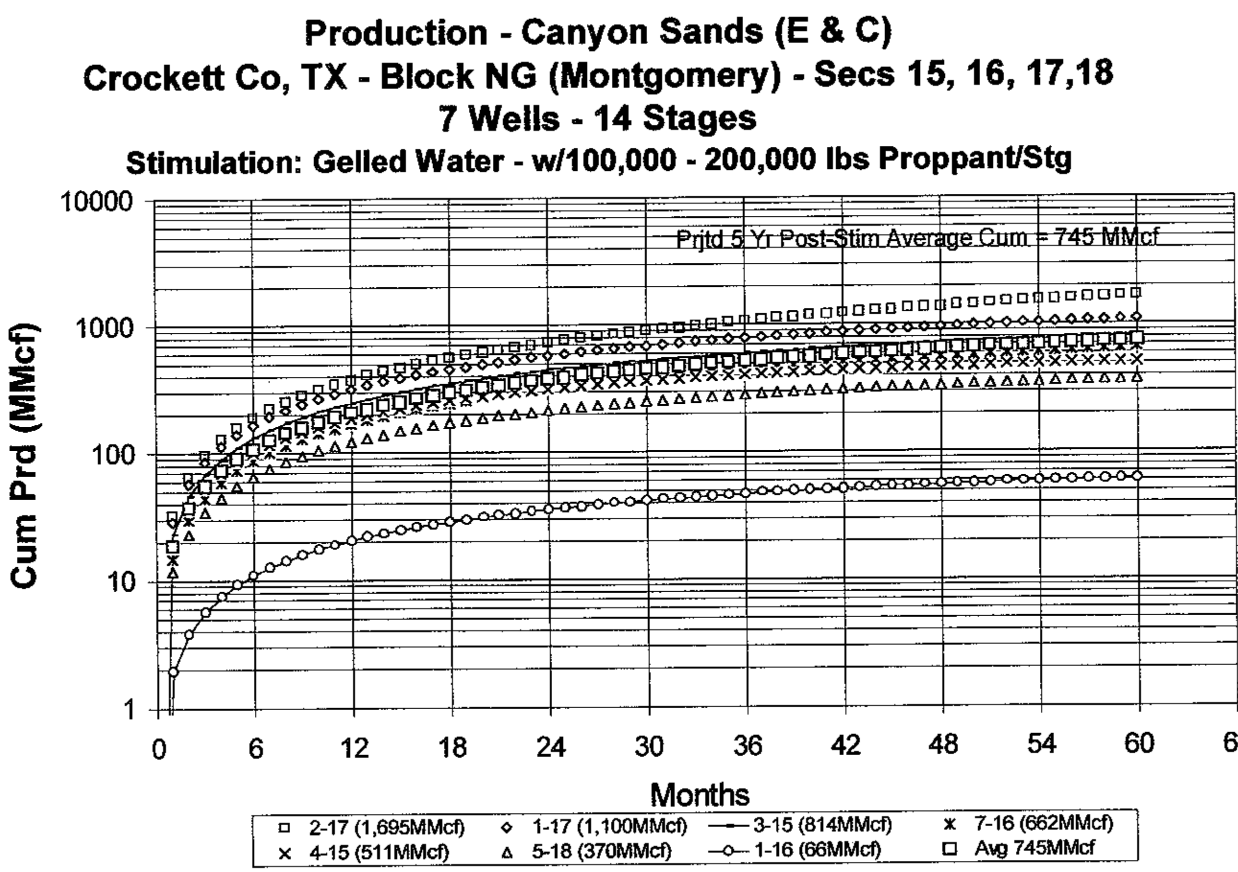
Summary							
		Sand (sacks)		Max Tr Press	Avg Rate	Sand Conc	
Well	St	Pumped	In-Zone	(psi)	(BPM)	Max	Avg
M#13	1	265	242	6,200	47.0	3.0	2.0
M#13	2	261	208	5,796	40.0	3.0	1.5
M#12	1	250	104	6,500	40.0	2.0	1.4
M#12	2	207	198	6,100	43.0	2.0	1.6
M#14	1	115	81	5,590	39.6	2.0	0.9
M#14	2	137	129	5,600	43.0	2.0	1.2

f. Results

(1) Production Comparisons

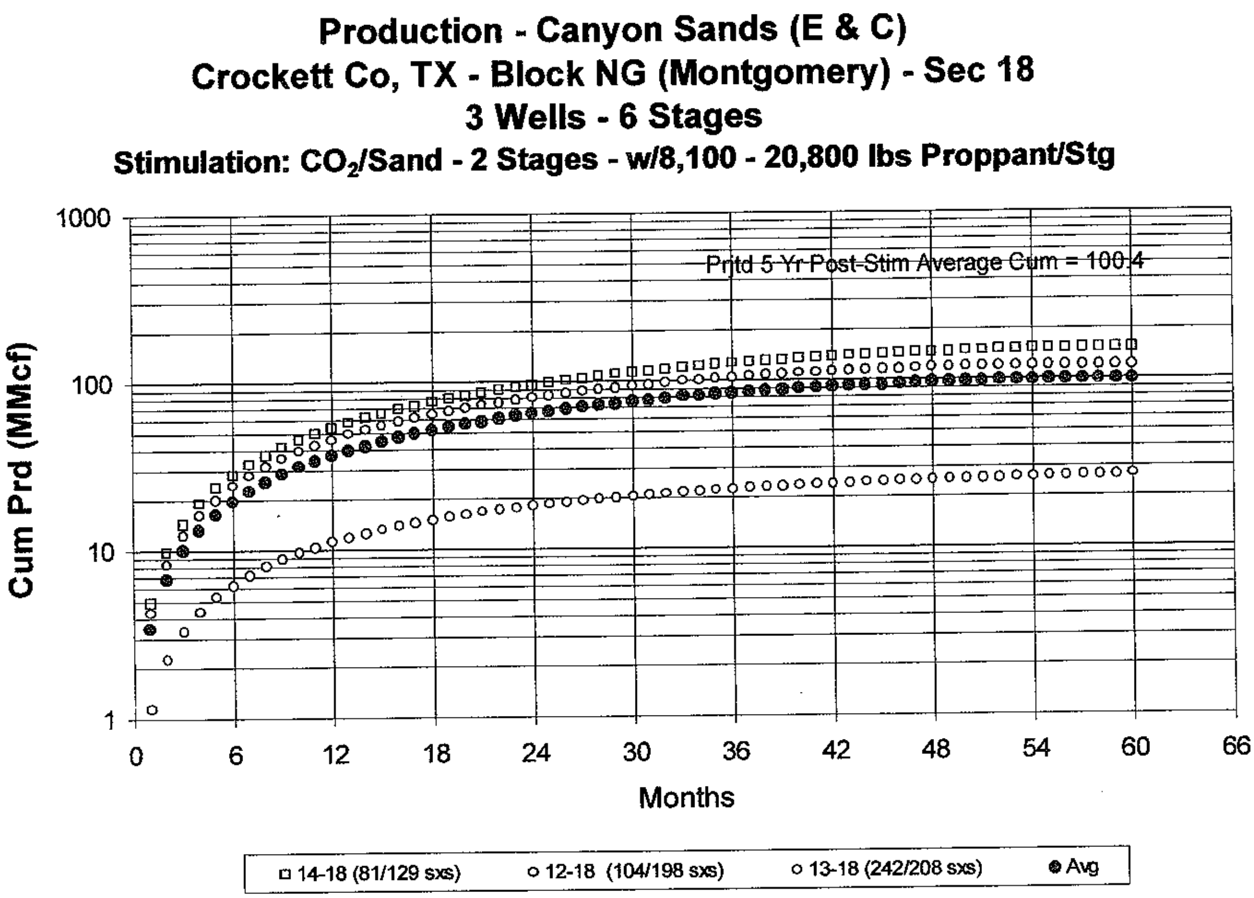
(a) Summary – Control Wells

The five year cumulative production volumes from the seven Control Wells ranged from 65.8 to 1,695.2 MMcf and averaged 745 MMcf.



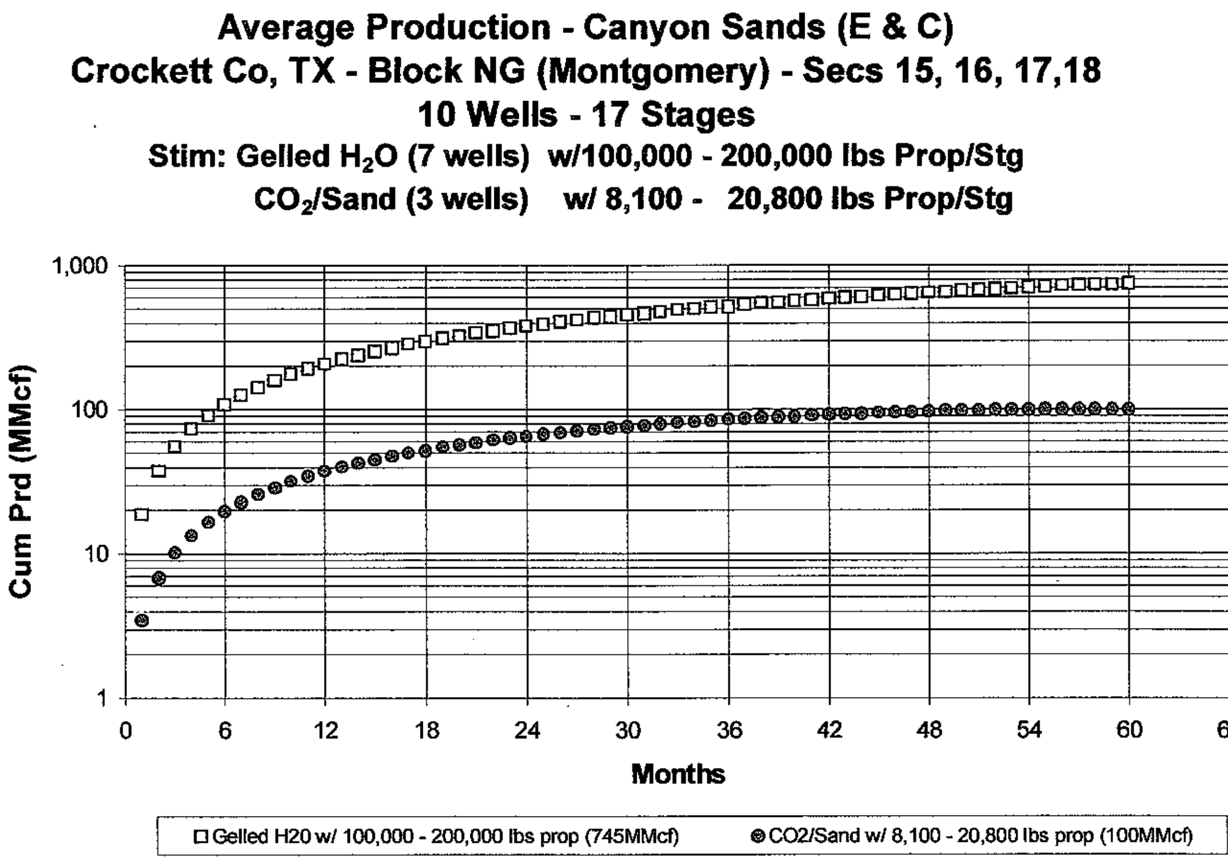
(b) Summary – Candidate Wells

The five year cumulative production from the three Candidate Wells ranged between 26.7 and 153.6 MMcf and averaged 100.4 MMcf.



(c) Summary Control and Candidate Wells

The projected five year cumulative production from the Candidate Wells averaged 100.4 MMcf while that from the seven Control Wells averaged 745.0 MMcf or 7.4 times that from the wells stimulated with the liquid CO_2/sand process.



g. Conclusions - Test Area #1A

(1) The liquid CO_2/sand stimulations were somewhat successfully pumped in the Canyon Sands. Although it had not been conclusively established that they could be successfully pumped they were, but at considerably reduced proppant volumes than the design.

(2) The production from the three Candidate Wells was considerably less than that from the Control Wells.

The projected five year cumulative production averaged 100.4 MMcf while that from the seven Control Wells averaged 745.0 MMcf or 7.4 times that from the wells stimulated with the liquid CO_2/sand process.

(3) These poor responses from the wells stimulated with the CO_2/sand process are unquestionably related to a number of factors regarding the formation characteristics of permeability, and pressure, <u>but to a larger extent to the reduced proppant volumes placed by the liquid-free treatments</u>

The conventional stimulations in both Test Areas #'s, 1A & 1B were stimulated with either borate cross-linked guar gum or HPC gels containing 100-200 thousand pounds of 20/40 mesh proppant whereas the proppant volumes placed with the liquid CO_2/Sand process were much less.

The proppant volumes in the liquid CO_2/sand treatments ranged from 8,100 to 24,200 pounds per stage. If the lowest volume, 8,100 pounds is removed, the five stage range was 10,400 to 24,200 and averaged

17,600 pounds or only 9 to 18 percent of that placed in the conventional treatments.

The actual volumes placed in zone were:

Stage 1			
	Pumped	Removed from well	Net in zone
Well	(K lbs)	(K lbs)	(K lbs)
Montgomery 13-18	26.5	2.3	24.2
Montgomery 12-18	25.0	14.6	10.4
Montgomery 14-18	11.5	3.4	8.1

Stage 2			
	Pumped	Removed from well	Net in zone
Well	(K lbs)	(K lbs)	(K lbs)
Montgomery 13-18	26.1	5.3	20.8
Montgomery 12-18	20.7	0.9	19.8
Montgomery 14-18	13.7	0.8	12.9

And, the ability to place the design quantities was obviously limited by

(a) The reduced pump rate of 40 barrels per minute, which was driven by a maximum tubular strength limitation of 6,500 psi.

(b) High leak off rates into the formation.

(c) In retrospect the inability of Halliburton to provide the design pump rate primarily because of the significant CO_2 leaks and the utilization of small diameter plungers compromised the ability to place proppant.

h. Significant equipment problems with CO_2 leakage around the piston rods was experienced. There were twelve Halliburton pumpers and the leakage became so severe that they were not visible from the blender operators position. They were shut down and partially remediated.

i. Costs

The costs for the CO_2/sand stimulations (6 wells - 9 stages) was $407,462 or $45,274 per stage. Cost advantages resulted from a major reduction in pumping costs through the utilization of a locally available service company, Halliburton Energy Services (HES). The original bid was much greater and also required a significant mobilization charge. To a lesser extent, a cost savings for CO_2 of $7,380 was realized by utilizing another supplier.

j. Well specific data

Well	Pmt # 42-105-xxxx	5 Yr Prod Projt'd	Stim Type, Sxs, Bbls
Montgomery 02-17	10786	1,695.2	
Montgomery 01-17	10785	1,100.2	
Montgomery 03-15	30742	814.4	
Montgomery 07-16	31725	662.0	
Montgomery 04-15	31021	510.9	
Montgomery 05-18	31727	370.8	
Montgomery 14-18	36987	153.6	CO_2 81, 635 CO_2 129, 538
Montgomery 12-18	36989	120.8	CO_2 104, 630 CO_2 198, 604
Montgomery 01-16	10101	65.8	
Montgomery 13-18	36988	26.7	CO_2 242, 588 CO_2 208, 583

6. <u>Test Area #1B - Block MM (Hoover-Hatton) – Single Stage Completions</u>

Block MM has approximately the same areal extent and the productive intervals are the lower G & H Canyon Sand intervals.

The previous spacing was 80 acres which was, at the time, reduced to 40 subject to a pending request. There were 25 producing wells in Block MM. Four CO_2/Sand stimulation sites were offered.

a. Control Wells

There were 10 Control Wells:

	Well	Pmt # 42-105-xxxx	5 Yr Prod Projt'd
1	Hatton 03-13	32174	434.2
2	Hoover 04-07	34267	332.5
3	Anderson 01-14	32307	292.5
4	Hatton 01-14	32124	187.0
5	Hatton 02-08	32004	163.1
6	Hatton 04-08	32260	161.3
7	Hatton 03-14	32182	146.5
8	Hatton 01-08	32003	131.4
9	Hatton 02-13	32165	91.6
10	Hatton 01-13	32143	62.8

b. Candidate Wells

The three Candidate Wells and ten Control Wells were situated in test area #1B and all were completed in the G & H Sands and stimulated with a single stage CO_2/sand treatment. The reservoir pressure was approximately 80 to 90% of the original and the EUR's have to exceed 300 million cubic feet of gas equivalence (300 MMcf) to meet the operators minimum economic hurdle.

	Well	Pmt # 42-105-xxxx	5 Yr Prod Projt'd
1	Hatton 13-14	36848	35.6
2	Hatton 7C-7	36960	89.9
3	Hatton 8C-4	36991	44.6

(1) Stimulation #1 - Candidate Well #1 - Hatton 13-14 (36848)

A total of 13,900 lbs of proppant were pumped at an average rate and pressure of 34.0 (39-5) barrels per minute and 6,600 psi respectively.

The pumping operation was terminated because of a screen out. It was being pumped at 39 bpm and a good deal of CO_2 leakage around the piston rod packings (12 pumps) reduced the injection rate by an estimated 5 bpm resulting in an actual through-wellhead rate of 34 bpm. The in zone proppant volume was estimated 5,600 pounds.

(2) Stimulation #2 - Candidate Well #2 - Hatton 7C-7 (36960)

A total of 11,200 lbs of proppant were pumped at an average rate and pressure of 39.5 barrels per minute and 5,800 psi respectively. The in zone proppant volume was estimated 10,200 pounds.

(3) Stimulation #3 - Candidate Well #3 - Hatton 8C-4 (36991)

A total of 14,000 lbs of proppant were pumped at an average rate and pressure of 40.0 barrels per minute and 5,800 psi respectively. The in zone proppant volume was estimated 11,700 pounds.

(4) Stimulation Summary

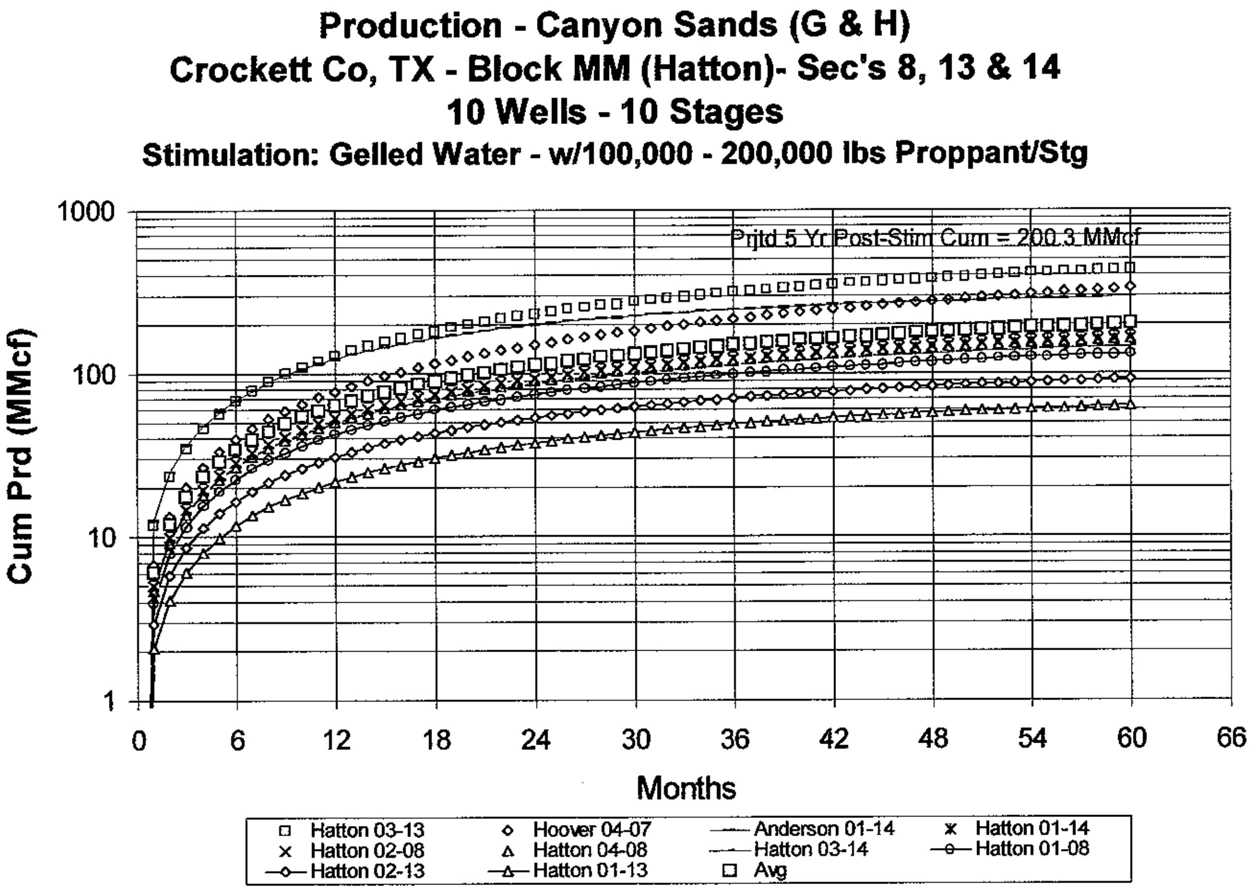
	Sand (sacks)		Max Tr Press	Avg Rate	Sand Conc	
Well	Pumped	In-Zone	Psi	BPM	Max	Avg
13-14	139	56	7,400*	39.0	2.0	1.1
7C-7	112	102	6,050	39.5	1.0	0.8
8C-4	140	117	6,250	40.0	2.0	1.0
* Well equipped with P-110 casing						

c. Results

(1) Production Comparisons

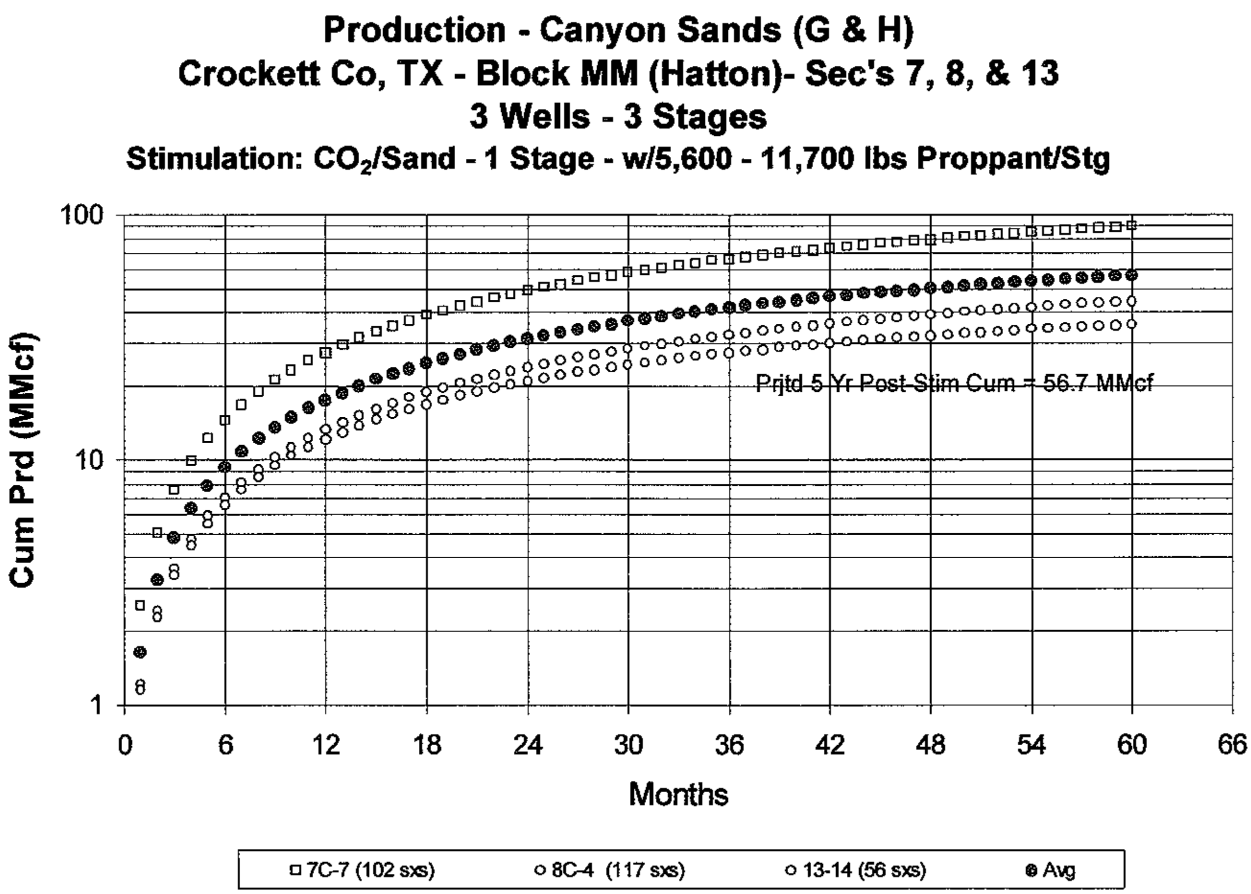
(a) Summary – Control Wells

The five year cumulative production from the ten Control Wells ranged between 62.8 and 434.2 MMcf and averaged 200.3 MMcf.



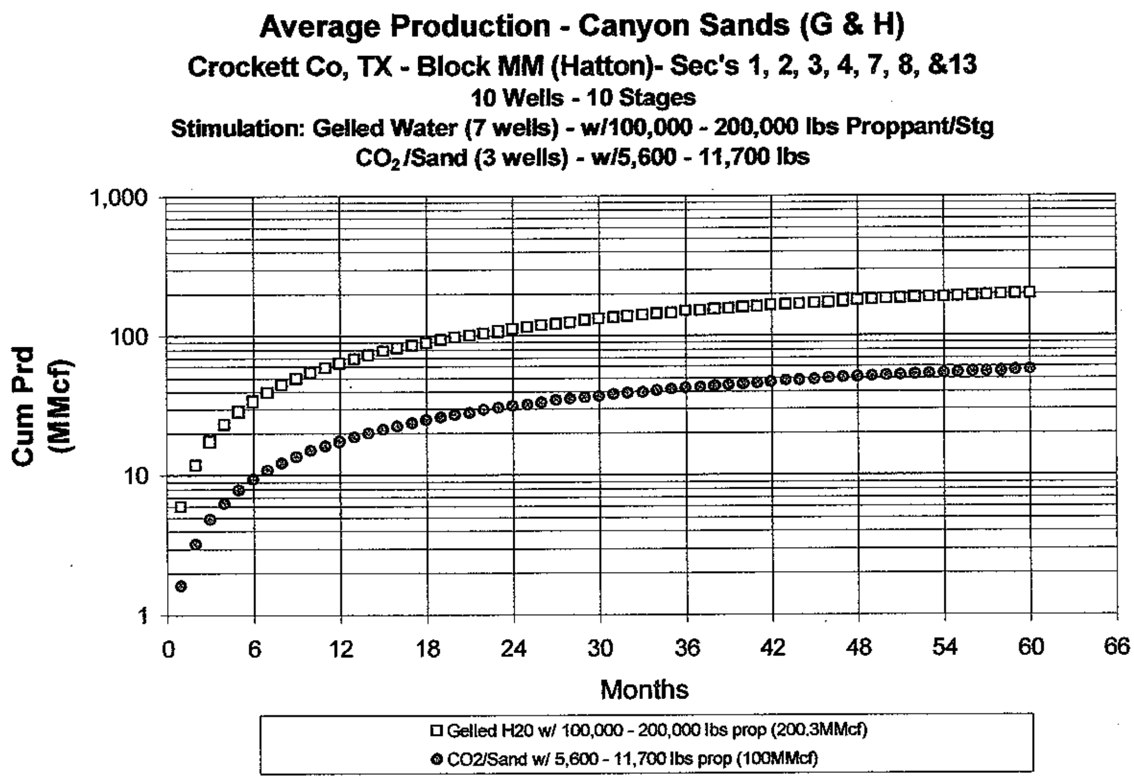
(b) Summary – Candidate Wells

The five year cumulative production from the three Candidate Wells ranged between 35.6 and 89.9 MMcf and averaged 56.7 MMcf.



(c) Summary Control and Candidate Wells

The production from the three Candidate Wells was considerably less than that from the Control Wells. The projected five year cumulative production ranged from 35.6 to 89.9 MMcf and averaged 56.7 MMcf. That from the ten Control Wells ranged from 62.8 to 434.2 MMcf and averaged 200.3 MMcf or 3.5 times that from the wells stimulated with the liquid CO_2/sand process.



d. Conclusions - Test Area #1B

(1) Liquid CO_2/sand stimulations were somewhat successfully pumped in the Canyon Sands. Although it had not been conclusively established that they could be successfully pumped they were, but at considerably reduced proppant volumes than the design.

(2) The production from the three Candidate Wells was considerably less than that from the Control Wells.

The projected five year cumulative production averaged 56.7 MMcf while that from the ten Control Wells averaged 200.3 MMcf or 3.5 times that from the wells stimulated with the liquid CO_2/sand process.

(3) These poor responses from the wells stimulated with the CO_2/sand process are unquestionably related to a number of factors regarding the formation characteristics of permeability, and pressure, but to a larger extent to the reduced proppant volumes placed by the liquid-free treatments

(4) The proppant volumes placed were much less than the design and ranged from 5,600 to 11,700 pounds or approximately twelve percent of that placed in conventional treatments. The actual volumes placed in zone were:

Well	Pumped (K lbs)	Removed from well (K lbs)	Net in zone (K lbs)
Hatton 13-14	1.39	8.3	5.6
Hoover 7C-7	11.2	1.0	10.2
Hatton 8C-4	14.0	2.3	11.7

And, the ability to place the design quantities was obviously limited by

(5) The reduced pump rate of 40 barrels per minute, which was driven by a maximum well head pressure of 6,500 psi.

(a) High leak off rates into the formation.

After the tubing was installed, the production levels would not support the additional expense of CO_2/Sand stimulations, even if the well with poor geology, 13-14, is eliminated.

e. Costs

The costs for the CO_2/sand stimulations (6 wells - 9 stages) was \$407,462 or \$45,274 per stage. Cost advantages resulted from a major reduction in pumping costs through the utilization of a locally available service company, Halliburton Energy Services (HES). The original bid was much greater and also required a significant mobilization charge. To a lesser extent, a cost savings for CO_2 of \$7,380 was realized by utilizing another supplier.

f. Well Specific Data

Well	Pmt # 42-105-	5 Yr Prod Proj	5 Yr Prod Actual	Prod Mo	Stim
	Xxxx	(MMcf)	(MMcf)		Type, Sxs, Bbls
Hatton 03-13	32174	434.2	449.6		
Hoover 04-07	34267	332.5	255.7		
Anderson 01-14	32307	292.5	173.0	40	
Hatton 01-14	32124	187.0	199.4		
Hatton 02-08	32004	163.1	166.9		
Hatton 04-08	32260	161.3	150.1		
Hatton 03-14	32182	146.5	160.0		
Hatton 01-08	32003	131.4	109.7		
Hatton 02-13	32165	91.6	89.9		
Hatton 7C-7	36960	89.9	79.1	46	CO_2 102, 640
Hatton 01-13	32143	62.8	65.3		
Hatton 8C-4	36991	44.6	44.3	45	CO_2 117, 659
Hatton 13-14	36848	35.6	23.8	45	CO_2 56, 466

7. Conclusions Test Areas 1A & 1B

a. With one exception, all nine stages, six on the Montgomery lease and three on the Hatton leases were rate-limited to approximately 40-43 barrels per minute because of the maximum allowable wellhead treating pressures of approximately 6,200 psi. Forty barrels per minute is approaching the minimum injection rates to reliably transport 20/40 size sand proppant.

b. The production from the Candidate Wells was disappointingly low:

(1) Test Area #1A - Block NG (Montgomery)

The projected five year cumulative production averaged 100.4 MMcf while that from the seven Control Wells averaged 745.0 MMcf or 7.4 times that from the wells stimulated with the liquid CO_2/sand process.

(2) Test Area #2 Block MM (Hoover)

The projected five year cumulative production averaged 56.7 MMcf while that from the ten Control Wells averaged 200.3 MMcf or 3.5 times that from the wells stimulated with the liquid CO_2/sand process.

(3) These poor responses from the wells stimulated with the CO_2/sand process are unquestionably related to a number of factors regarding the formation characteristics of permeability, and pressure, <u>but to a larger extent to the reduced proppant volumes placed by the liquid-free treatments</u>

(4) The placed proppant volumes with the CO_2/sand process were much lower than the design volumes:

(a) Test Area #1A - Block NG (Montgomery)

The proppant volumes placed were much less than the design and ranged from 8,100 to 24,200 pounds per stage. If the lowest volume, 8,100 pounds is removed, the five stage range was 10,400 to 24,200 and averaged 17,600 pounds or approximately twelve percent of that placed in conventional treatments.

The actual volumes placed in zone were:

Stage 1			
	Pumped	Removed from well	Net in zone
Well	(K lbs)	(K lbs)	(K lbs)
Montgomery 13-18	26.5	2.3	24.2
Montgomery 12-18	25.0	14.6	10.4
Montgomery 14-18	11.5	3.4	8.1

Stage 2			
	Pumped	Removed from well	Net in zone
Well	(K lbs)	(K lbs)	(K lbs)
Montgomery 13-18	26.1	5.3	20.8
Montgomery 12-18	20.7	0.9	19.8
Montgomery 14-18	13.7	0.8	12.9

i) The treatments are summarized

		Sand (sacks)		Max Tr Press	Avg Rate	Sand Conc (lb/gal)	
Well	Stg	Pumped	In-Zone	Psi	BPM	Max	Avg
M#13	1	265	242	6,200	47.0	3.0	2.0
M#13	2	261	208	5,796	40.0	3.0	1.5
M#12	1	250	104	6,500	40.0	2.0	1.4
M#12	2	207	198	6,100	43.0	2.0	1.6
M#14	1	115	81	5,590	39.6	2.0	0.9
M#14	2	137	129	5,600	43.0	2.0	1.2

(b) Test Area #2 Block MM (Hoover)

The proppant volumes placed were much less than the design and ranged from 5,600 to 11,700 pounds or approximately twelve percent of that placed in conventional treatments. The actual volumes placed in zone were:

	Pumped	Removed from well	Net in zone
Well	(K lbs)	(K lbs)	(K lbs)
Hatton 13-14	1.39	8.3	5.6
Hoover 7C-7	11.2	1.0	10.2
Hatton 8C-4	14.0	2.3	11.7

(5) The ability to place the design quantities was obviously limited by:

(a) The reduced pump rate of 40 barrels per minute, which was driven by a maximum well head pressure of 6,500 psi.

(b) High leak off rates into the formation.

i) The treatments are summarized

	Sand (sacks)		Max Tr Press	Avg Rate	Sand Conc (lb/gal)	
Well	Pumped	In-Zone	Psi	BPM	Max	Avg
Hatton 13-14	139	56	7,400	39.0	2.0	1.1
Hoover 7C-7	112	102	6,050	39.5	1.0	0.8
Hatton 8C-4	140	117	6,250	40.0	2.0	1.0

(6) The costs for the CO_2/sand stimulations (6 wells - 9 stages) was $407,462 or $45,274 per stage. Cost advantages resulted from a major reduction in pumping costs through the utilization of a locally available service company, Halliburton Energy Services (HES). The original bid was much greater and also required a significant mobilization charge. To a lesser extent, a cost savings for CO_2 of $7,380 was realized by utilizing another supplier.

(7) In retrospect the inability of Halliburton to provide the design pump rate primarily because of the significant CO_2 leaks and the utilization of small diameter plungers compromised the ability to place proppant.

Significant equipment problems with CO_2 leakage around the piston rods was experienced. There were twelve Halliburton pumpers and the leakage became so severe that they were not visible from the blender operators position. They were shut down and partially remediated.

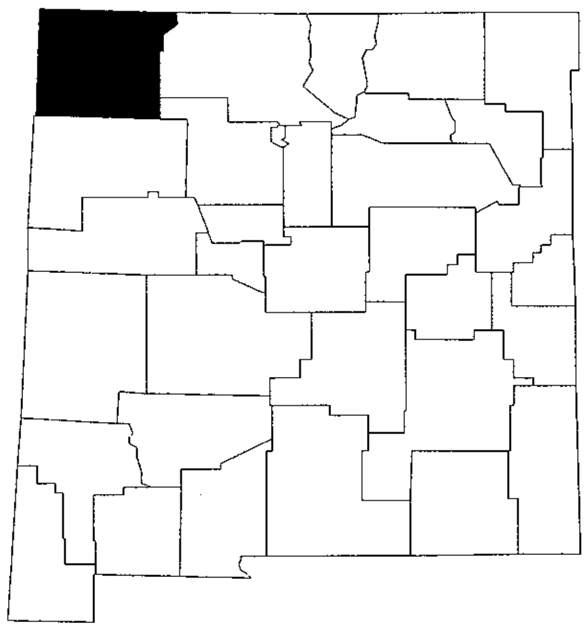
(8) Summarizing, the conclusion is that fracture lengths longer than those which can be generated with CO_2/Sand stimulations are required in this area. It is too "tight".

(9) The production from only one well, Montgomery #14, exceeded the economic hurdle rate, the others are significantly below the economic rate, the conclusion is that larger fracture lengths than can be generated with CO_2/Sand stimulations are required in this area. It is too "tight".

B. TEST AREA #2 – San Juan Co, NM - Package # 2 – 3 Stage / 3 Wells

1. Location

Northeast New Mexico near the town of Blanco.



The Candidate Well(s) are completed in the Fruitland Coals which are an Upper Cretaceous sequence of interbedded sandstones, siltstones, shale, and coal which lie a depth of 2,000-2,500 feet in the Test Area. The coals have thicknesses of 36-60 feet, and the basal coal, Cahn, is 45 to 60 feet thick, and is the most productive. It along with other overlying coal members were stimulated. The treated intervals ranged from 120 to 180 feet.

The Candidate Wells were considered to provide a good opportunity to demonstrate the CO_2\Sand stimulation process in a liquid-sensitive reservoir where the capillary retention of stimulation liquids was known to be detrimental to gas production. And, if the treatments turned out to be successful, then the marginal nature of this portion of this reservoir (Type III) would become more economically attractive.

2. Operator – Amoco Production

In 1995 Amoco Production Company (Amoco) - now BP - had an active drilling program in the Fruitland Coals in San Juan County, New Mexico and indicated a strong interest in participating in the DOE's cost shared demonstration project to evaluate the potential of the liquid-free, CO_2/Sand stimulation technology.

3. Reservoir

The Fruitland Coal wells on the Fairway are in an area designated as Type I and typically produce up to 1,000 Mcf per day along with 10-50 barrels of water (GLR = 20-100 Mcf/bbl) from the reservoir at a pressure of 600-800 psi. To the north of the Fairway in the Type II area the wells produce gas at 0-500 Mcf per day and 10-50 barrels of water (GLR = 25-50 Mcf/bbl).

		Reservoir Pressure		Gas prod	Water	GLR
Type	Location	$P_{original}$	P_{now}	Mcfd	Bwpd	Mcf/bbl
I	Fairway (FW)	1000	600-800	>1000	10-50	20-100
II	NE of FW	1000	600-800	0-500	10-20	25-50
III	SW of FW (Target)	500	500	0-250	1-2	125-250

4. Producing Horizon - Type III Area

In the Type III area southwest of the Fairway where the Candidate Wells are situated, the production is typically 0-250 Mcf per day and is essentially water free. The wells can produce 1-2 barrels of liquid daily (GLR = 165 Mcf/bbl), sometimes mostly condensate which may originate in the underlying Pictured Cliff Sandstone(PC).

5. Reservoir Pressure and Temperature

The reservoir pressure and temperature in the area where the Candidate Wells are situated is approximately 500 psi and 102 degrees Fahrenheit respectively.

Well	Temp (°F)	Total Depth (ft)
Florance GCL-1	N/R	2,206
Florance Q-1	105	2,264
Riddle I-1	101	2,277

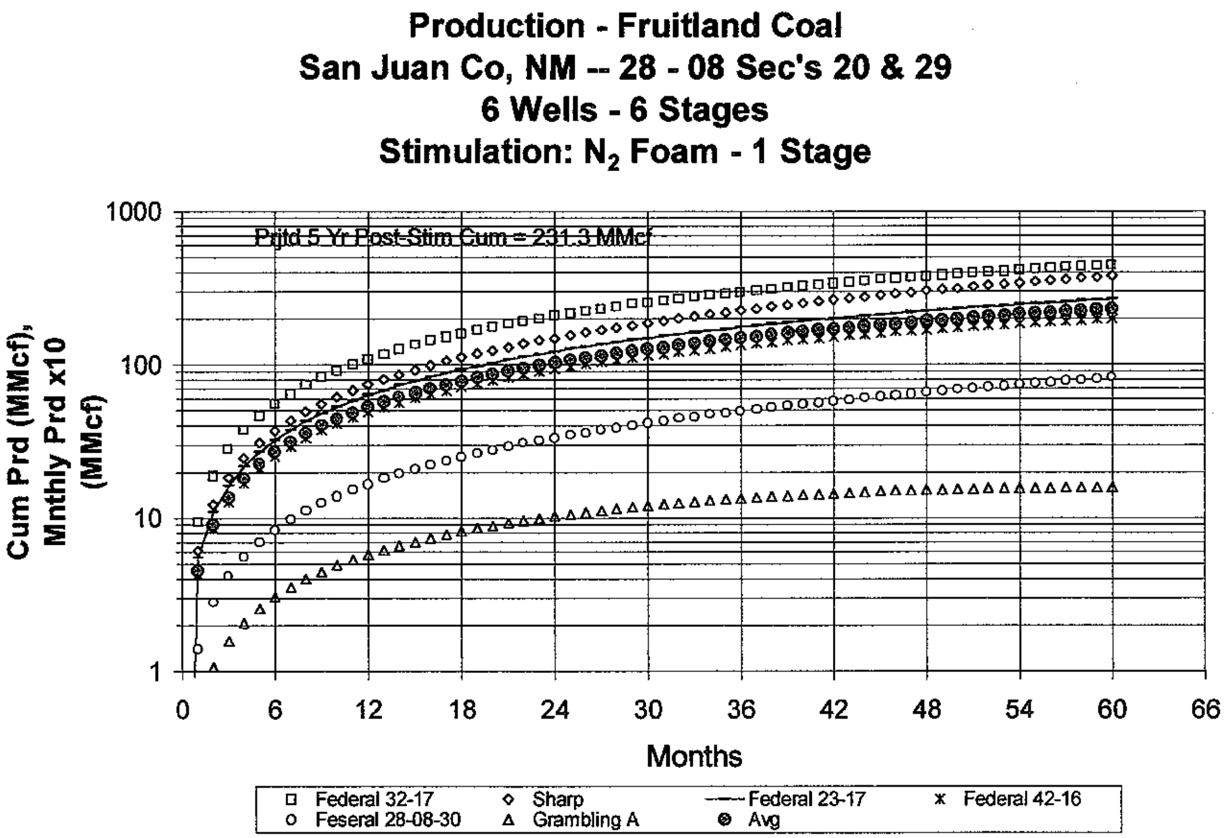
A review of the phase behavior at these temperatures and pressures confirmed that the CO_2 would vaporize under these conditions. A phase diagram for each well group was prepared and is not included here, but accompanies the report for that group

6. Control Wells

There were 6 Control Wells

	Well	Pmt # 30-045-xxxx	5 Yr Prod Projt'd
1	Federal 32-17	28472	445.2
2	Sharp	21160	378.7
3	Federal 23-17	28471	266.6
4	Federal 42-16	28337	199.8
5	Federal 28-08-30	28863	81.8
6	Grambling A	21041	15.6

a. The five year cumulative production from the six Control Wells ranged between 15.6 and 445.2 MMcf and averaged 231.3 MMcf.



7. Candidate Wells

There were three Candidate Wells.

Well*	Lease	Pmt #	1st Yr Dly Prod (Mcfd)
3	Florance GCL1	29336	140
4	Florance Q1	29328	150
2	Riddle I1	29345	110

a. Perforation Strategy

The perforation placements were identified from the electric logs and positioned at the coal intervals which have lower bulk densities. The accompanying electric logs (Figures 7 to 9) indicate this placement technique.

Well	Interval (ft)	Perfs
Riddle I-1	120	200
Florance GCL-1	180	316
Florance Q-1	158	288

b. Stimulations

(1) Candidate Well #1 - Florance GCL-1 (29336)

A total of 9,800 lbs of proppant were pumped in 137 bbls of CO_2 at an average rate and pressure of 55.8 barrels per minute and 2,226 psi respectively. The well screened out with 7,500 lbs of proppant through the perforations. The in zone proppant volume was estimated 7,500 pounds.

(2) Candidate Well #2 – Florance Q-1 (29345)

An effort to increase the placed volume included increasing the pad volume from 90 to 148 barrels along with an increase in the initial sand concentration from 1.0 to 1.5 pounds per gallon (ppg). A total sand-laden CO_2 volume of 101 bbls was pumped which was less than the 137 pumped in the first well treated, Candidate Well #2, Florance GCL-1.

A total of 6,200 lbs of proppant was pumped at an average rate and pressure of 55.8 barrels per minute and 2,145 psi respectively. The maximum sand concentration was 1.9 lbs per gal, and averaged 1.5. The in zone proppant volume was estimated 4,800 pounds.

(3) Candidate Well #3 - Riddle I-1 (29328)

The treatment was modified and it was considerably more successful in that 130 sacks of sand were placed in zone.

A total of 15,200 lbs of proppant was pumped at an average rate and pressure of 50.0 barrels per minute and 2,517 psi respectively. The increased sand volume which was placed in this well is likely result of:

(a) The reduced number of perforations 200 vs. 288 and 316 in the other two Candidate Wells

(b) The introduction of a 20 bbl 0.5ppg sand slug in the middle of the pad

(c) Maintaining a reduced sand concentration of 0.75 ppg.

c. Stimulation Summary

(1) All three wells screened out and the treatments were terminated. Following the screen out of the first treatment the pad volume was increased from 90 to 148 bbls and the starting sand concentration increased from 1.0 to 1.5 ppg yet a lesser in zone proppant volume resulted. This response indicates that increasing the pad volume provides no benefit, and that the ability to transport sand at concentrations of 1.0 ppg or greater is unlikely.

(2) The largest sand volume was placed in the third treatment, Riddle I-1 which included a 20bbl - 0.5ppg sand slug in the pad and a reduced sand concentration of 0.75 ppg.

(3) A contributing factor is believed to be the large number of perforations (200 to 316).

(4) The "in-zone" sand volumes and other specifics were:

		Sand (sacks)		Max Tr Press	Avg Rate	Sand Conc (lb/gal)	
Well	Perfs	Pumped	In-Zone	Psi	BPM	Max	Avg
Riddle I-1	200	152	130	4,702	50.0	1.9	0.8
Florance GCL-1	316	98	75	3,576	55.8	2.5	1.6
Florance Q-1	288	62	48	4,100	55.8	1.9	1.5

(5) There was inter-zonal communication between the Fruitland Coal and the Pictured Cliff Sandstone.

When stimulating all three of the Candidate Wells there were increases in production and/or casing pressure in the offset wells (on the same location) as the CO_2 treatments were being pumped.

These offset wells were completed in the Pictured Cliff Sandstone, but not the Fruitland Coals.

(a) Florance GCL-1

The casing pressure in the offset well increased from 148 to 185 psi, and the production increased from 158 to 165 Mcf per day indicating the communication with the Candidate Well.

(b) Florance Q-1

The casing pressure in the offset well increased from 144 to 160 psi, and the production increased from 130 to 138 Mcf per day indicating the communication with the Candidate Well.

(c) Riddle I-1

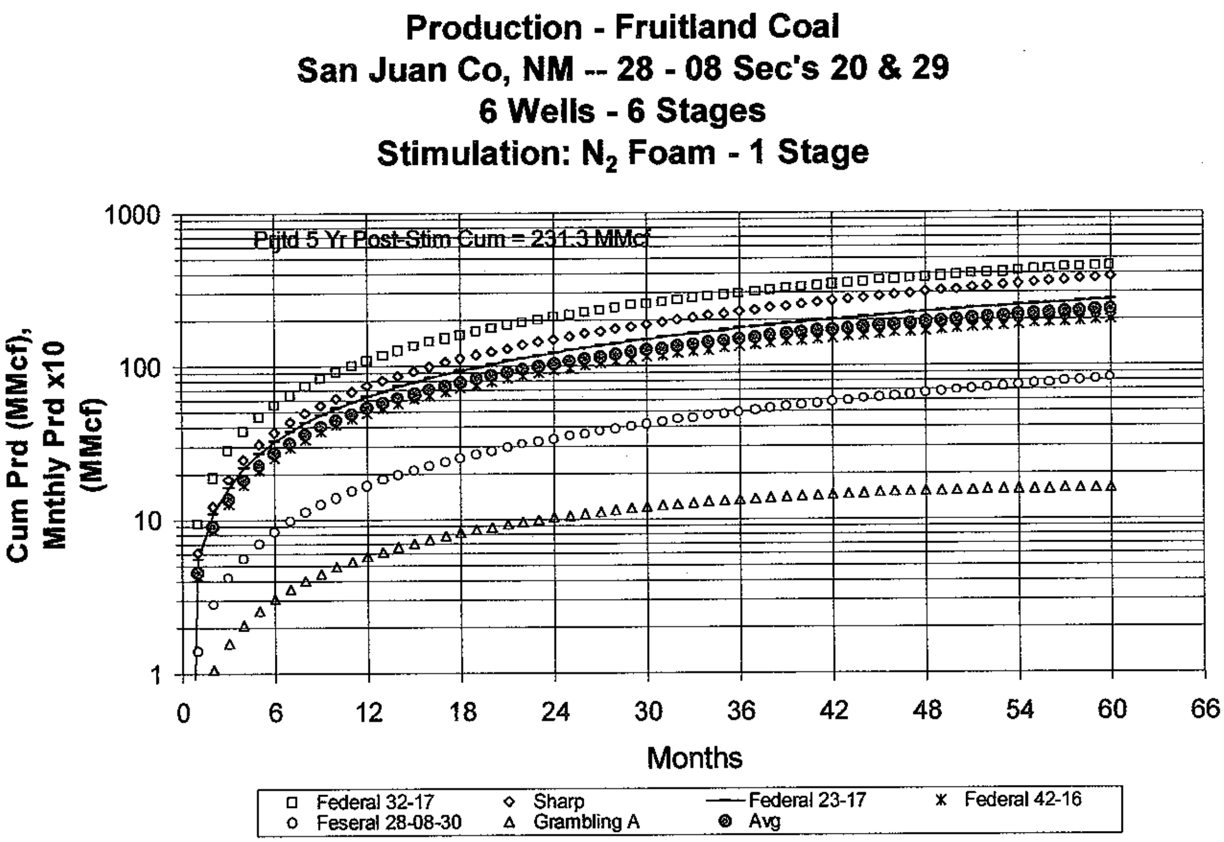
The casing pressure in the offset well increased from 127 to 460 psi, and the production increased from 190 to 420 Mcf per day indicating the communication with the Candidate Well. Additionally, a gas sample was obtained following the treatment and was reported to contain 44% CO_2, indicating communication between these formations. The offset well was perforated in the basal section (Cahn) of the Fruitland Coal. The Candidate Well was not.

8. Results

a. Production Comparisons

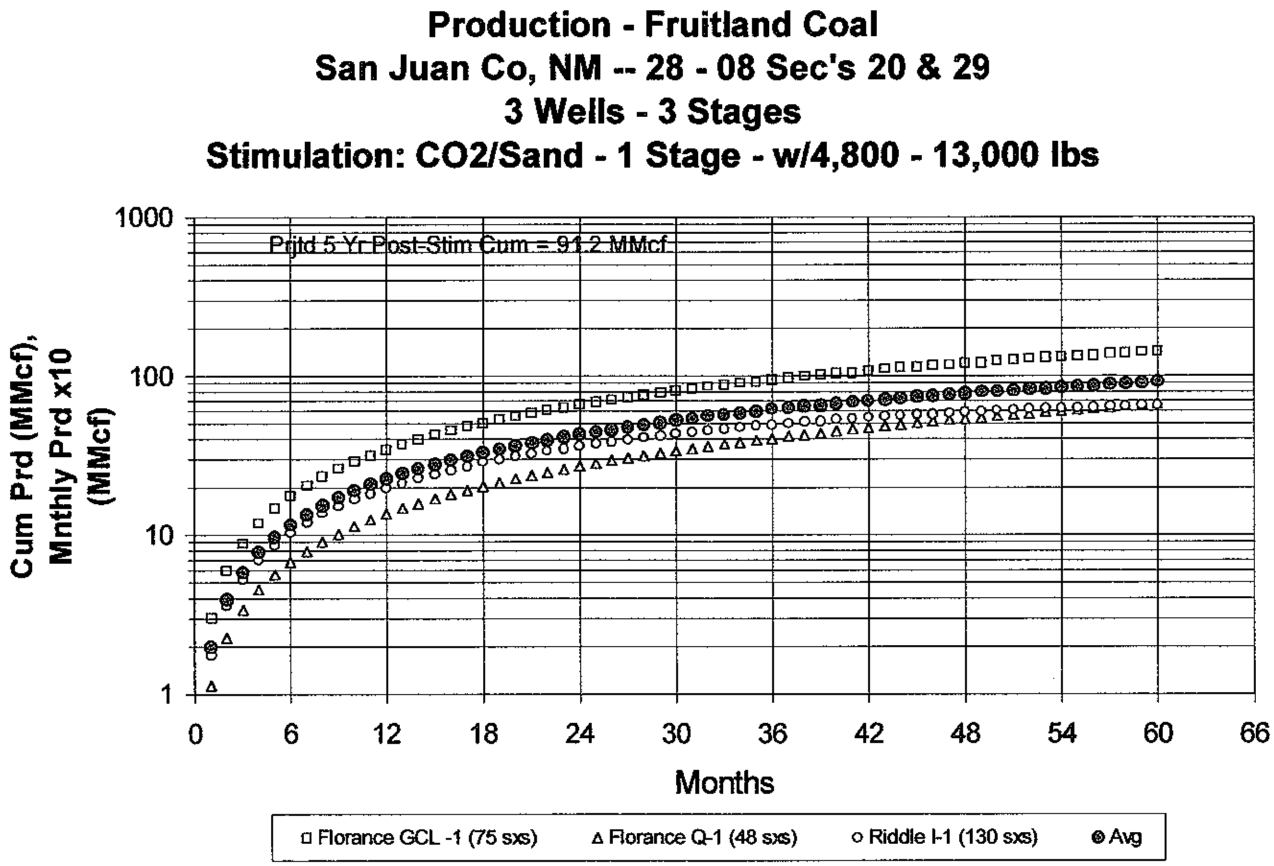
(1) Summary – Control Wells

The five year cumulative production from the six Control Wells ranged between 15.6 and 445.2 MMcf and averaged 231.3 MMcf.



(2) Production Summary – Candidate Wells

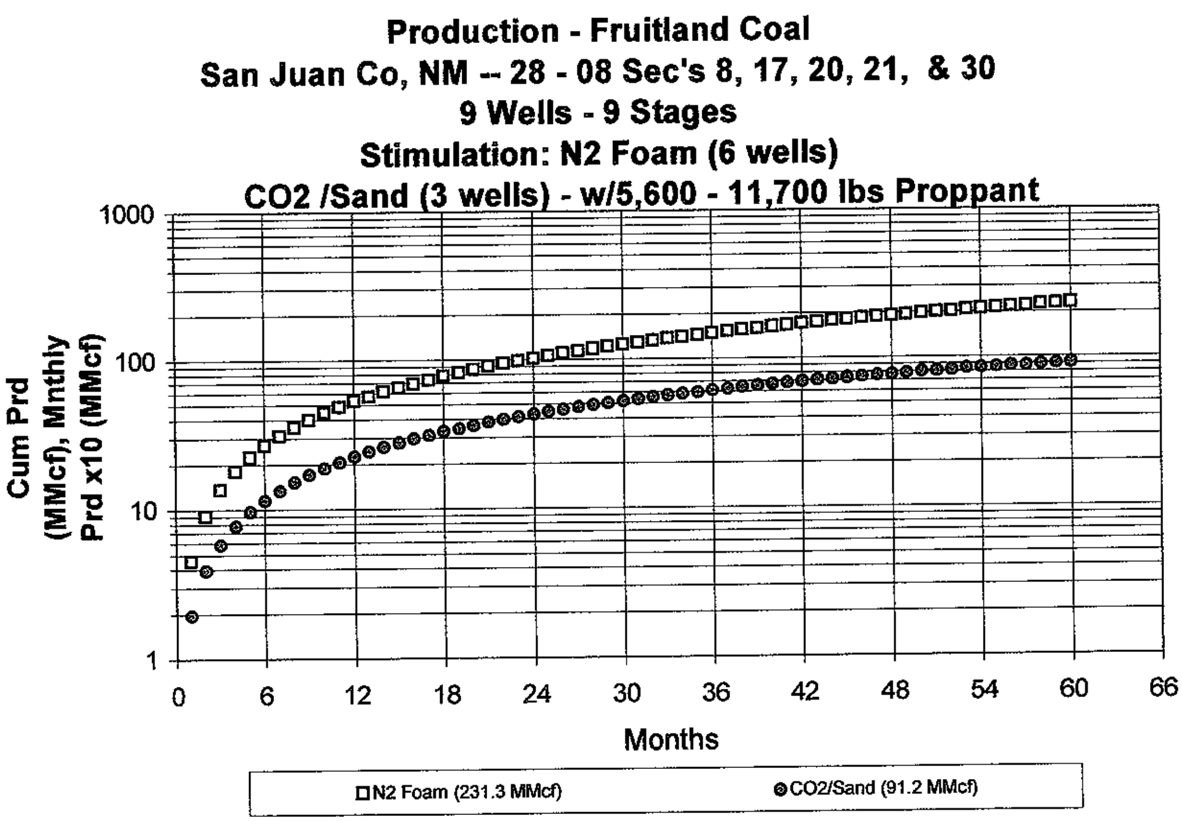
The five year cumulative production from the three Candidate Wells ranged between 65.3 and 141.9 MMcf and averaged 91.3 MMcf.



(3) Summary Control and Candidate Wells

The five year cumulative production volumes from the three Candidate Wells ranged from 65.3 to 141.9 averaging 91.3 MMcf or 39 percent that of the six Control Wells.

These poor responses from the wells stimulated with the CO_2/sand process are unquestionably related to a number of factors regarding the formation characteristics of permeability and pressure, but to a larger extent to the reduced proppant volumes placed by the liquid-free treatments. In the test area, the conventionally stimulated wells were stimulated with 70-75q nitrogen foam containing 250,000 pounds of sand, or The proppant volumes placed were much less than the design and ranged from 4,800 to 13,000 pounds and averaged 8,433 lbs or approximately three percent (3%) of that placed in conventional treatments.



b. Costs

(1) Projected

The projected costs for stimulating these wells with 120 tons of liquid CO_2 and 40,320 pounds of sand were:

Wells	3	4
Totals	$178,340	$236,200

(2) Actual

The actual costs for the CO_2/sand stimulations were:

01/22/96 Cost Summary Page 1 of 1

Number	Riddle I-1	Florance GCL #1	Florance Q-1	
Pumping ($)(UWS)	19,660	19,139	16,791	
N2 (HES)	1,695	3,632	2,044	
Sand (HES)	2,046	891	705	
Misc				
	23,401	23,661	19,540	66,603
CO2 (BOC)	6,654	7,447	8,186	
CO2-Portables (BOC)	1,200	1,200	1,200	
Mob (BOC)	2,000	2,000	2,000	
Blender (UWS)	6,000	6,000	6,000	
Tube Trailer (UWS)	5,500	5,500	5,500	
	21,354	22,147	22,886	66,386
Mob,Per Diem (UWS) Trucking	2,080	9,600		
Mob,Per Diem (UWS) Misc		2,840		
	2,080	12,440	0	14,520
Total	46,835	58,248	42,426	147,509

c. Conclusions

(1) The projected five year cumulative production ranged from the three Candidate Wells ranged from 65.3 to 141.9 MMcf and averaged 91.3 MMcf while that from the six Control Wells ranged between 15.6 and 445.2 MMcf averaging 231.3 MMcf or 2.5 times that from the wells.

(2) The cost of the conventional treatments was not disclosed but it is evident that the inability to place increased proppant volumes with the liquid CO_2/sand process irrespective of the cost resulted in a significant advantage of the conventional treatments because of the larger production rates.

(3) These poor responses from the wells stimulated with the CO_2/sand process are unquestionably related to a number of factors regarding the formation characteristics of permeability, and pressure, but to a larger extent to the reduced proppant volumes placed by the liquid-free treatments

d. Well specific data

Well	Pmt # 30-045-	5 Yr Prod Projt'd	Stim
	xxxx		Type, Sxs, Bbls
Federal 32-17	28472	445.2	
Sharp	21160	378.7	
Federal 23-17	28471	266.6	
Federal 42-16	28337	199.8	
Florance GCL 1	29336	141.9	CO_2 75, 227
Federal 28-08-30	28863	81.8	
Florance Q1	29345	66.6	CO_2 48, 249
Riddle I-1	29328	65.3	CO_2 130, 513
Grambling A	21041	15.6	

The cost of the liquid CO_2 treatments averaged $49,170 per well (1 stage), and the five year cumulative production averaged 91.3MMcf or $0.54 per MCF. The stimulation costs for the conventional treatments was not disclosed by Amoco.

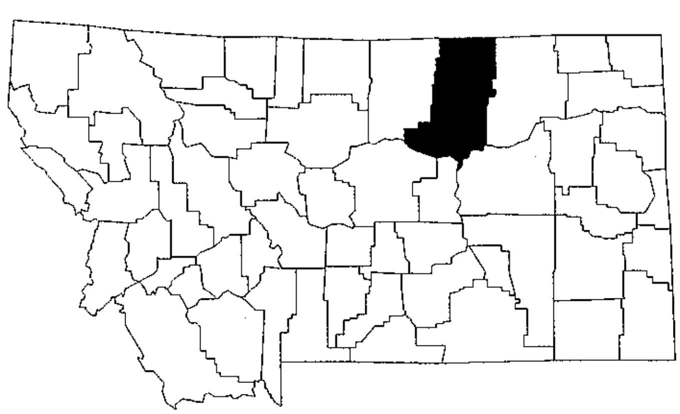
The placed proppant volumes obtained in the liquid CO_2 treatments was only on the order of three percent (3%) of that placed with conventional treatments, and although the production from the liquid CO_2 stimulations averaged 39 percent of that from the conventionally stimulated wells suggesting that production parity could be obtained if larger proppant volumes were pumped with the CO_2/sand treatments, this ability is presently considered to be unrealistic.

C. TEST AREA #3 - Phillips Co, Mt - Package # 5 – 3 Stages / 3 Wells

1. Location

The fourth group of wells to be treated are situated within the Williston Basin in Phillips County near the town of Saco in north-central Montana.

The test area was located in the northern most segments of WBI's Bowdoin Dome drilling boundaries and is approximately rectangular with dimensions of 2-1/2 by 3 miles. It is nine miles northwest of the town of Saco and three miles north of the Nelson reservoir. It includes seven sections within townships 32N and 33N and Range 32E. It included the three Candidate Wells, #'s 1019, 1020, and 1021, and at the time of the test, sixteen Control Wells consisting of nine existing wells and seven new wells all of which were stimulated with nitrogen Foam.



2. Operator

Fidelity Exploration & Production Co (formerly Williston Basin Interstate Pipeline Company (WBI) - subsidiaries of MDU Resources) was the operator of a large number of wells in the Bowdoin Dome in Phillips County, Montana.

3. Reservoir

The Phillips Sands constitute a volumetric drive reservoir with minimal water production. The in-place gas reserves range from 30 to 60 Mcf per acre foot which results in calculated producible reserves within the test area ranging between 175 and 400 MMcf per well. The annual decline rates range from 15 to 20 percent following a two to three month period of higher rate "flush production". Typical water production rates are as much as, but generally less than one barrel per month. The water is discharged into and quickly evaporates from an earthen pit. The majority of the pits show little if any indication of ever containing produced water. Within the test area the reservoir pressure, as measured by shut-in wellhead pressures ranges from 287 to 396 psi

4. Producing Horizon

The Bowdoin Dome is within the Williston Basin and is centered in Phillips County, Montana, approximately 50 miles west of the Ft. Peck Indian Reservation. It has been producing natural gas in commercial quantities since the 1920's from several Upper Cretaceous age formations, the Lower Phillips Sandstone being the deepest.

It along with the Upper Phillips are the producing formations in the three Candidate Wells which are the focus of this demonstration. These wells produced from the Phillips Sandstone, a shallow (1,200 ft), lower pressure (300 psi) Upper Cretaceous formation that was suspected of being damaged by conventional N_2 Foam stimulation procedures.

It had been estimated that 81% of the spent stimulation liquids remain in the Phillips and that these liquids could be damaging the reservoir and reducing the gas producing potential.

a. Reservoir Pressure and Temperature

Generally the reservoir pressure and temperature are 300 psi and 70°F and the pipeline pressure is approximately 100 psi.

b. Gas properties

The gas composition is 93% methane, 6% nitrogen, and 1% other gases, which results in a biogenic gas with a calorific value of 950 BTU per cubic foot.

c. Sensitivity to Stimulation Liquids

The Control Wells were stimulated with 65 quality nitrogen Foam. Because of the liquid sensitive nature, lower pressure of these formations, and the reduced volume of the stimulation load water returned, which has been estimated to be 81%, it was suspected that the advantages of a liquid-free stimulation could result in an economic benefit.

5. Control Wells

The production projections were based on the observations made from the produced volumes from the nearby Control Wells which were all perforated in both the Upper and Lower Phillips Sand members-Cumulative for Months 2 through 13.

Control Wells (N_2 Foam)								
Existing Wells (Stimulated Prior to 07/98)								
					API #	Cum Prod (MMcf)		
Well #	Twp	Rge	Sec	Quad	25-071-	Month 2	Month 13	Month 2-13
972	33N	32E	27	NW	22267	1.046	25.433	24.387
973	33N	32E	32	SE	22268	1.187	80.759	79.572
974	33N	32E	33	NE	22269	0.874	55.875	55.001
976	33N	32E	35	NW	22272	0.441	56.654	56.213
990	32N	32E	02	NW	22275	12.699	83.790	71.091
991	32N	32E	01	NE	22279	9.158	63.894	54.736
997	33N	32E	32	NE	22287	?????	32.568	32.568
1000	32N	32E	02	SE	22283	10.880	71.401	60.521
1002	33N	32E	33	SE	22288	9.671	66.678	57.007
							Avg (n=8)	57.316

6. Candidate Wells

The Candidate Wells were selected on the basis of their representative nature and position within the field, distance from an established reservoir boundary, and their proximity to conventionally stimulated Control Wells.

There was no difficulty encountered in placing the smaller proppant in the first treatment and, as planned, efforts were made to obtain 12/20 proppant which was being stored nearby and at the time being utilized by another service company in the execution of the N_2 Foam stimulations on other WBI wells. Unfortunately, although the proppant was available and dedicated to WBI, the other service company, Halliburton Energy Services would not make it available presumably because the CO_2/sand stimulations were being performed by a competing service company, Canadian Fracmaster.

The conventional stimulations utilize approximately the same proppant volume as that for a CO_2/sand treatment although of a larger size (12/20 vs. 20/40). The similarities of the proppant volumes resulted in a like comparison of the production resulting from the two stimulation types.

It should be noted that upon review and comparison of the production histories that there is a question as to whether the production rates from the CO_2/sand stimulations would have been greater and especially more variable if the larger proppant had been used.

7. Success criteria

Upon review of the production responses from the conventionally stimulated wells drilled prior to July, 98 it was agreed that, based upon the available information, the criteria success would be realized if <u>the cumulative production for months 2 through</u>

13 would be 50 MMcf if they were conventionally stimulated with nitrogen Foam and 40,000 pounds of proppant.

By mutual agreement it was agreed that this should serve as the measure by which the evaluation of the CO_2/sand stimulations would be judged.

Well #	Cum Prod Months 2-13 (MMcf)
1019	50
1020	50
1021	50

8. Stimulations

a. Stimulation #1 – Well # 1021 (Candidate Well #1)

The first well stimulated with CO_2/sand was well #1021. It was stimulated with 44,100 lbs of 20/40 API specification proppant and 103 tons of liquid CO_2. The treatment consisted of a total of 536 Barrels of liquid CO_2 pumped at an average rate of 45.3 barrels per minute and an average pressure of 943 psi and a maximum of 1740 psi. The treatment design was to intentionally under flush to provide a proppant packed fracture to the well bore and an estimated quantity of 700 lbs was left in the casing - leaving an in-zone total of 43,400 lbs.

b. Stimulation #2 – Well # 1020 (Candidate Well #2)

The second well stimulated with CO_2/sand was well #1020. It was stimulated with 44,100 lbs of 20/40 API specification proppant and 86 tons of liquid CO_2. The treatment consisted of a total of 447 Barrels of liquid CO_2 pumped at an average rate of 45.9 barrels per minute and an average pressure of 870 psi and a maximum of 1,363 psi. An in-zone total of 43,400 lbs of proppant was placed.

c. Stimulation #3 – Well # 1019 (Candidate Well #3)

The third well stimulated with CO_2/sand was well #1019. It was stimulated with 32,100 lbs of 20/40 API specification proppant and 62 tons of liquid CO_2. The treatment consisted of a total of 321 barrels of liquid CO_2 pumped at an average rate of 40.9 barrels per minute and an average pressure of 754 psi and a maximum, at screen out, of 2,886 psi.

This last treatment did screen out as the sand concentration was increased and the sand concentration at the perforations was 5.2 ppg - the recorded sand loading at the surface was 8.2 pounds per gallon at the tail end of the treatment. This design was intentional to determine the maximum sand acceptance loading. In reality, without being able to discern it, it appears that the likely maximum sand concentration of approximately 5 ppg was approached during the first treatment. An estimated quantity of 4,400 lbs (300 ft) was left in the well bore above the perforations.

9. Costs

a. Conventional Stimulation

The cost of typical nitrogen foam stimulation in July 1998, at the time of the test was $18,500 including nitrogen. The cost was reported earlier as $25,000 which included $5,000 for nitrogen and was initially used to project the required ratio for an economic success.

b. CO_2/Sand Stimulation

The projected costs for stimulating these wells with CO_2/sand was:

Equipment	$16,053.79
Materials	35,957.65
CO_2	incl
	52,011.44
Computer Control	1,080.00
Report	427.50
	53,518.94
3 Wells	160,556.82
Mobilization	17,500.00
	178,056.82
Per Well (÷ 3)	59,352.27
Cost to WBI	29,676.14
Cost to DOE	29,676.13
	$59,352.27

c. Projected vs. Actual

The actual costs for the treatments was less than projected primarily because of reduced CO_2 volumes as a result of the accelerated sand schedules.

Costs	Stimulation	Isolation Tool	Total
Projected	178,056.82	6,333.00	184,389.82
Actual	161,871.10	6,543.00	168,414.10
Differences	(16,185.72)	210.00	(15,975.72)

10. Results

a. Production Comparisons

It was readily apparent that the cumulative gas production for months two through thirteen from all of the new wells, drilled within the control area in 1998 were less than those drilled previously. Consequently the production has been tabulated in three stimulation type groups:

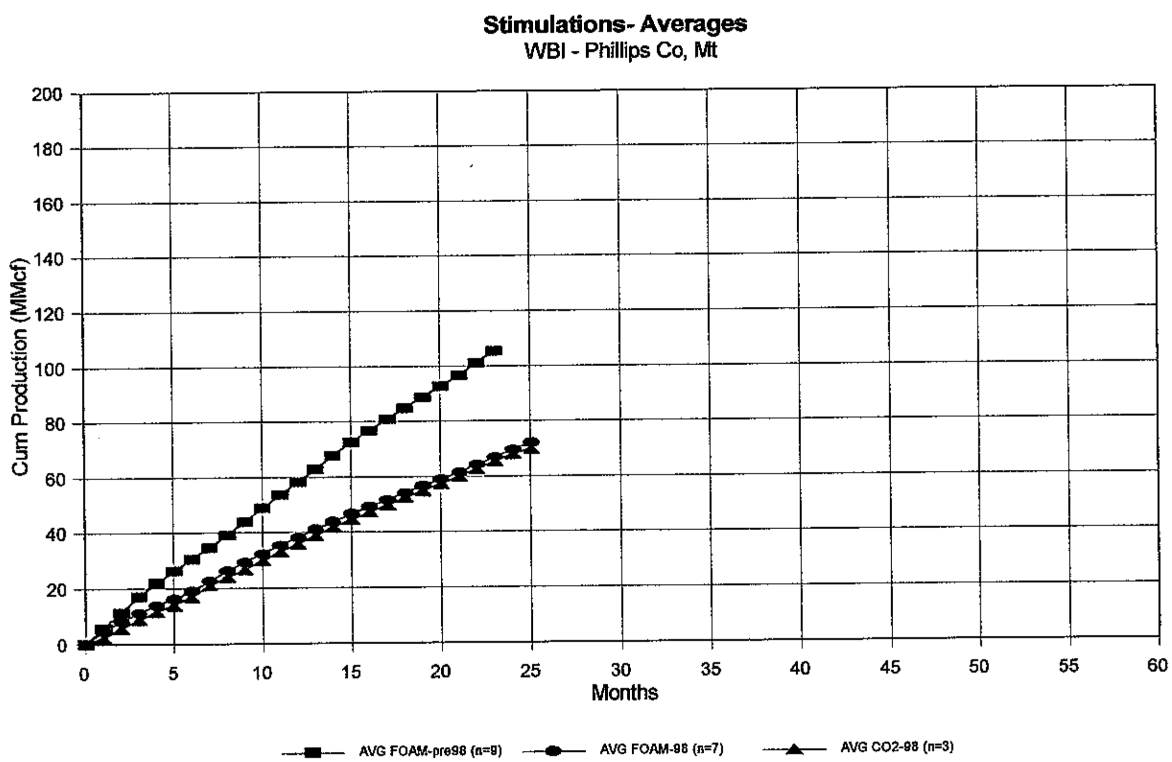
(1) N_2 Foam - Pre July 1998 (Control Wells)

(2) N_2 Foam - July 1998 (Control Wells)

(3) CO_2/Sand - July 1998 (Candidate Wells)

The average cumulative gas productions from each of these groups has been plotted and it dramatically indicates the superiority of the production from the pre 98 wells.

The cumulative production averages from both of the 98 Control (Group 2) and Candidate Wells (Group 3) are identical and considerably less than those drilled prior to 98 (Group 1).



It was determined later that the reduced production from the wells completed after 1998 was a result of reduced well spacing and reduced reservoir pressure.

A potential explanation is that the larger proppant size, 12/20 and greater sand concentration, 12 pounds per gallon utilized on the N_2 Foam stimulations may be offsetting proppant embedment? That is, that the smaller proppant (20/40) and the reduced proppant loading utilized for the CO_2/sand stimulations was resulting in a smaller propped fracture width.

11. Proppant size

Because there is some question as to whether the size of the proppant utilized in the stimulations may impact the production rates a review of the different size proppants used in twenty wells within the Bowdoin Field was made. The cumulative production was compared by utilizing the following information:

Number of Wells			
	Proppant Size		
Stim Type	08/16	12/20	20/40
N_2 Foam:	8	9	
CO_2/Sand:			3

12. Conclusions

a. Full proppant volume (40,000 pound) CO_2/sand stimulations were easily executed in the Phillips Sand in the Phillips Co, Montana test area

b. The maximum sand concentration for CO_2/sand stimulations being pumped at 40 barrels per minute is approximately 5 pounds per gallon. The first well stimulated (1019) accepted 5.9 ppg without any indications of rejection. For design purposes a maximum proppant loading for 40,000 lbs of 20/40 mesh proppant pumped at 40 bpm is 5 ppg.

c. The criteria for success was that the cumulative production from months two through thirteen had to exceed 50 MMcf. This hurdle was based on the production from other nearby wells which were drilled prior to 1998 and also perforated in both the Upper and Lower Phillips Sandstone members.
Only one of the ten wells stimulated in 1998, 1013 met this success criteria.

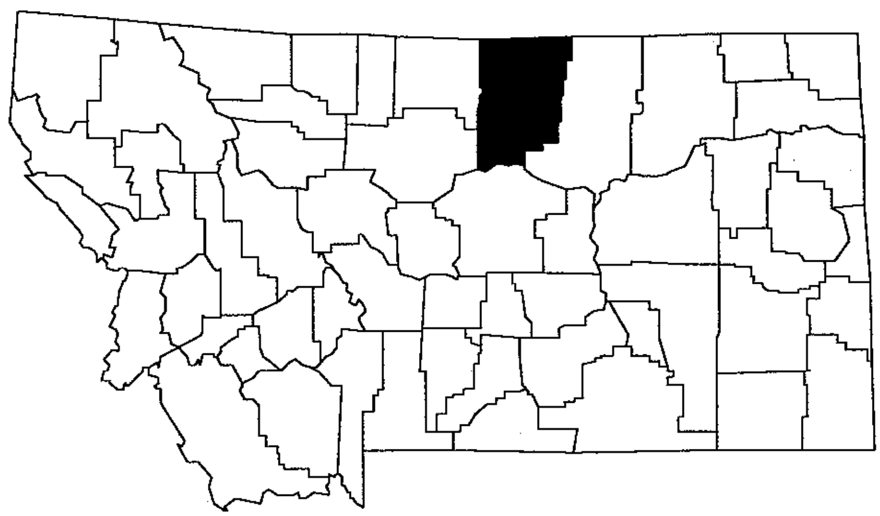
d. The twenty-four month cumulative production volumes from the wells stimulated with the liquid-free CO_2/sand process are essentially the same as that from the Control Wells treated with N_2 Foam and utilizing the same 40,000 pound proppant volume.

e. There is a suspicion that the wells which were stimulated with CO_2/sand are being choked by limited conductivity in the hydraulically created fracture, probably as a consequence of the smaller proppant size used (20/40 vs. 12/20). This is based on the observation of the nearly identical monthly production volumes from all three Candidate Wells. And, also on the production comparisons of twenty nearby wells which utilized larger proppant.

D. TEST AREA #4 - Blaine Co, Mt - Package # 7 – 4 Stages / 4 Wells

1. Location

Blaine County is situated in north-central Montana and is bounded on the north by Saskatchewan. The Tiger Ridge Field where the demonstration tests were located is north of the Bear Paw Mountains within Township 30N-Range 18E near the town of Havre.



2. Operator

Ocean Energy, Inc. (Ocean) was the largest gas producing company in Montana and was the operator of record for approximately 650 producing gas wells in the north-central area of the state, southeast of Havre

3. Reservoir

a. Porosity Permeability, Thickness, and EUR

The porosity ranges from 15 to 25 percent with permeability's ranging from 10 to 60 md and the completed thickness for both the Upper and Middle Eagle

Sands approaches 100 feet, depending on the gas/water contact. The newer wells produce approximately 150 Mcf daily and have EUR's on the order of 400 MMcf. Older wells which were drilled at virgin pressure had EUR's ranging generally up to 2BCF.

b. Reservoir Pressure and Temperature

The lower pressure reservoir portions where the Candidate Wells are located are in the Tiger Ridge field which is north of the Bear Paw mountains. This lower pressure section has been extensively drilled, and is now pressure depleted (225 psi). It generally will not clean up following the liquid-based stimulation treatments. Whereas the areas south of the Bear Paw mountains have significantly greater pressure, 500 psi, and can be successfully stimulated with nitrogen foam.

The reservoir pressure as measured by shut-in wellhead pressures in the Candidate Wells ranges from 175 to 297 psi in the test area:

Well	S - #	Pi (Psi)
T30N-R18E		
S-B Ranch	02-05	N/A
Blackwood	06-09	222
Kane	05-08	175
Kane	05-05	297
Kane	04-12	204
S-B Ranch	02-11	225

And, the reservoir temperature is approximately 70 degrees F.

c. Gas Properties

The gas composition is made up of methane, ethane, and nitrogen. There are no sulfur gases nor carbon dioxide present:

Component	Mol pct
C_2H_4	96.5
C_3H_8	0.5
$CO2$	0.0
N_2	3.0
Sulfur Compounds	0.0
Total	100.0

which results in a biogenic gas with a calorific value of 983 BTU per cubic foot (wet basis).

4. Producing Horizon

These wells produce from a shallow, 1,500 to 2,000 feet Upper Cretaceous formation (Eagle Sandstone) which in certain pressure depleted segments of the Tiger Ridge field is irreversibly damaged by the liquids used in conventional nitrogen foam stimulations.

5. Sensitivity to Stimulation Liquids

This reduced pressure, relatively* dry gas reservoir has a long history of being successfully stimulated with conventional water-based stimulations. Unfortunately, because of the reduced reservoir pressure, the spent stimulation liquids remain in the formation for an extended period and thereby reduce the permeability to gas. The sensitivity of this reservoir to liquids is a consequence of the inability of the reduced pressure to displace the stimulation liquids as opposed to the more conventional conditions of formations reactivity such as swelling shale.

* The completion practices are to perforate the Upper Eagle and the Middle Eagle Sand above any liquid as indicated by the electric logs. The wells do produce very slight volumes of water which are lifted with velocity strings, and any entrained liquid is carried in the gas and does not collect in the separators nor is there any liquid in the tanks.

6. Control Wells

There were no Control Wells included in this effort because the Candidate Wells were actively producing wells which enabled both the pre- and post-stimulation production rates to be measured and compared.

This approach is unique to this effort because in the past the producing wells had been previously stimulated with liquid-based treatments and the reservoir was considered to be damaged by these stimulation liquids. Consequently, the CO_2/Sand stimulations had to be performed in new, unstimulated wells and, the existing previously stimulated wells served as the Control Wells to which the production responses were compared.

This approach in measuring the pre- and post-stimulation response from wells which have never been stimulated is superior to that which utilized the Control Wells because the well specific variables of porosity, thickness, etc. are eliminated.

7. Candidate Wells

There were four Candidate Wells. They are listed in the order considered by Ocean to provide the greatest opportunity to demonstrate and evaluate the effectiveness of the CO_2/Sand stimulation technology, that is, the S-B Ranch 02-05 is considered to be the most desirable for stimulation. (Ultimately Blackwood 06-09 had the largest incremental improvement of 54.1 MMcf following 22 producing months following the stimulation).

Well						Stim Type	Rem	Skin	Prod	Pi
T30N-R18E	S - #	Upr Eagle Perfs	Mid Eagle Perfs	Lwr Eagle Perfs	PB Req'd	Sxs, Bbls	MMcf		Mcfd	Psi
S-B Ranch	02-05	1120-1202 1134–1197w/12	1222-1260 1220–1261w/ 8	1283-1290 None	No	None	484.345	TBD	35	170
Kane	05-08	1359-1334 1362-1380w/22	1436-1502 1388-1408w/ 26	1515-1538 None	Yes@1420	None	359.000	+2.00	100	175
Kane	05-05	1094-1142 1110–1136w/42	1168-1233 1170-1220w/ 74	1283-1290 None	Yes@1150	None	96.700	+12.9	60	297
Blackwood	06-09	1142-1188 1144–1147w/20	1241-1288 1156-1162w/ 18	1302-1328 None	No	None	986.500	+2.83	220	222

a. Completion

The completion technique was to set and cement casing, generally 4-1/2 in, through the Eagle Sands, run electric logs to determine the gas/water contact, and perforate above it. Generally, the Upper Eagle and upper section of the Middle Eagle were perforated. No stimulations were generally performed because the reservoir pressure (225 psi) was insufficient to expel the spent stimulation liquids

b. Perforation Strategy

The design criteria was to limit the number of perforations to a maximum of 40. Because of the large number of perforations in three of the Candidates, and the associated concern regarding an insufficient transport velocity, the design included temporarily plugging-off the lower perforations during the stimulation.

Well							Total Perfs
T30N-R18E	S - #	Upr Eagle Perfs	Mid Eagle Perfs	Lwr Eagle Perfs	PB Req'd	Add'l Perfs	During Stim
S-B Ranch	02-05	1120-1202 1134–1197w/12	1222-1260 1220–1261w/ 8	1283-1290 None	No	20	40
Kane	05-08	1359-1334 1362-1380w/48	1436-1502 1388-1408w/ 34	1515-1538 None	Yes@1420	-34	48
Kane	05-05	1094-1142 1110–1136w/42	1168-1233 1170-1220w/ 74	1283-1290 None	Yes@1150	-74	42
Blackwood	06-09	1142-1188 1144–1147w/20	1241-1288 1156-1162w/ 18	1302-1328 None	No	0	38

c. Production Review and Projections

All four of the proposed Candidate Wells produce from both the Upper and Middle Eagle Sand members. None were perforated in the Lower Eagle. Three of the Candidate Wells contained a large number of perforations which were considered to be too many and for the CO_2/Sand process.

This was because the proppant transport rate into the individual perforations would be insufficient to transport the proppant and would increase the likelihood of a screen out.

The wells were rank-ordered by Ocean in their recommended sequence which was believed to provide the most benefit. This rank ordering results in the plugging of the Lower Eagle Sand in the wells which are ranked 3, 4, and 5, which almost dictates that at least one of the three Candidates will require plugging of the Middle Eagle and treating the Upper sand member only.

Well						Prod
T30N-R18E	S - #	Upr Eagle Perfs	Mid Eagle Perfs	Lwr Eagle Perfs	PB Req'd	(Mcf/d)
S-B Ranch	02-05	1120-1202 1134–1197w/12	1222-1260 1220–1261w/ 8	1283-1290 None	No	35
Kane	05-08	1359-1334 1362-1380w/22	1436-1502 1388-1408w/ 26	1515-1538 None	Yes@1420	100
Kane	05-05	1094-1142 1110–1136w/42	1168-1233 1170-1220w/ 74	1283-1290 None	Yes@1150	60
Blackwood	06-09	1142-1188 1144–1147w/20	1241-1288 1156-1162w/ 18	1302-1328 None	Yes	220

In order to properly measure the production response associated with the CO_2/Sand treatment, a producing period sufficient to eliminate the production from the un stimulated interval (Middle Eagle) was agreed to.

Ocean installed the temporary plugs immediately before the stimulation and then removed it after 22 months following the CO_2/Sand stimulation. This procedure allowed for the stimulation of only the Upper Eagle while comparing the post-stimulation production from both the Upper and Middle Sands.

The production histories for the Candidate Wells were plotted and accompanied the submittal package to the DOE. The production rates for each well was identified, and used as an input to determine the minimum annual post-stimulation production necessary to achieve an economic success.

8. Success Criteria

The evaluation was conducted within a controlled setting to enable an objective assessment of the production responses resulting from these stimulations to be made. The Candidate Wells had been completed in the target formation and were selected on the basis of their upside potential for production rate improvement, a commercial volume of remaining reserves, and mechanical suitability for this demonstration (number of perforations & tubing diameter). The proposed Candidates had a sufficient background production history to provide the basis for comparing the post-stimulation production rates following the CO_2/Sand stimulations.

The completion, remaining production, and some reservoir properties of the Candidate Wells were obtained and are summarized as:

Vell	S - #	T	Upr Eagle	Mid Eagle	Lwr Eagle	PB Req'd	H_2O	Stim Type	Rem	Skin	Prod	Pi	P*
		°F	Perfs	Perfs	Perfs		Lvl	Sxs, Bbls	MMcf		Mcf/d	Psi	Psi
T30N-R18E													
-B Ranch	02-05	72	1120-1202 1134–1197w/12	1222-1260 1220–1261w/ 8	1283-1290 None	No	TBD	None	484.345	TBD	35	170	TBD
Kane	05-08	72	1359-1334 1362-1380w/22	1436-1502 1388-1408w/ 26	1515-1538 None	Yes@1420	TBD	None	359.000	+2.00	100	175	95
Kane	05-05	72	1094-1142 1110–1136w/42	1168-1233 1170-1220w/ 74	1283-1290 None	Yes@1150	TBD	None	96.700	+12.9	60	297	83.5
Blackwood	06-09	72	1142-1188 1144–1147w/20	1241-1288 1156-1162w/ 18	1302-1328 None	No	TBD	None	986.500	+2.83	220	222	114

The criteria for success has been developed for each Candidate Well and was based on the following assumptions:

a. An economic success required that the cost benefit associated with the production rates resulting from the CO_2/Sand stimulations will have to exceed the pre-stimulation production revenues by a discounted cash flow which equals or exceeds the cost of the treatment

b. Capital cost for the CO_2/Sand stimulation treatment: $86,000. This was a previous estimate which was at the time considered to likely be greater than the actual cost. In that event the production hurdle rates will be recalculated using the actual treatment cost.

c. Market price: $2.50/dth – fixed

d. Calorific value: 1000 BTU/CF

e. Discount rate: 25%

f. Production decline rate: Variable and driven by the production projections supplied by Ocean.
The evaluation was not further burdened by the operating expenses because they are presently being incurred and would be the same irrespective of the treatment.

These inputs were used to determine the following total uninterrupted and unencumbered minimum annual production volumes as indicated below, necessary for an economic success.

The methodology was to project the production from the historical production rates for each well, and then to add an incremental production rate to compensate for the cost of the treatment. The total of these two components, the projected production rate and the incremental value to offset the stimulation cost, equals the minimum total production rate required for an economic success.

The individual production projections and the incremental rates necessary to provide the discounted cash flow have been calculated on an annual basis, for five years and are included in the individual well sections, and are summarized:

T30N-R18E		Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Total
Well	# - S	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)
From:		06/01/02	06/01/03	06/01/04	06/01/05	06/01/06	06/01/02
Through:		05/31/03	05/31/04	05/31/05	05/31/06	05/31/07	05/31/07
S-B Ranch	02-05	25,199	21,421	18,208	15,474	13,153	93,455
Kane	05-08	47,626	42,501	37,927	33,845	30,203	192,102
Kane	05-05	33,063	24,485	18,134	13,428	9,944	99,054
Blackwood	06-09	90,383	85,593	81,057	76,761	72,692	406,486

Ocean concurred that these production projections will serve as the basis for establishing the success criteria, and if the actual production volumes from these Candidate Wells exceed these tabulated annual production volumes, subject to adjustments for any non-producing intervals, then Ocean agreed that the CO_2/Sand stimulation process will have resulted in an economic benefit.

9. Stimulations

a. Stimulation #1 – S-B Ranch 02-05 (25-041-22955) (Candidate Well # 1)
A total of 10,300 lbs of proppant and 432 bbls (83 Tons) of CO_2 were pumped at an average rate and pressure of 37.8 barrels per minute and 2,318 psi respectively.

The treatment screened out at a sand concentration of 2.4 ppg with 1,800 lbs of proppant in the wellbore leaving 8,500 lbs of proppant in-zone.

b. Stimulation #2 – Kane 05-08 (25-041-22279) (Candidate Well # 2)
A total of 27,300 lbs of proppant and 835 bbls (161 Tons) of CO_2 were pumped at an average rate and pressure of 31.0 barrels per minute and 3,032 psi respectively. The in zone proppant volume was estimated 24,900 pounds.

c. Stimulation #3 - Kane 05-05 (25-041-22557) (Candidate Well # 3)
A total of 23,800 lbs of proppant and 815 bbls (157 Tons) of CO_2 were pumped at an average rate and pressure of 46.0 barrels per minute and 2,581 psi respectively. The in zone proppant volume was estimated 21,800 pounds.

d. Stimulation #4 – Blackwood 06-09 (25-041-22161) (Candidate Well # 4)
A total of 10,600 lbs of proppant and 633 bbls (122 Tons) of CO_2 were pumped at an average rate and pressure of 20.0 barrels per minute and 3,321 psi respectively. The in zone proppant volume was estimated 10,400 pounds.

e. Stimulation Summary

The stimulation specifics of the four Candidate Wells are summarized:

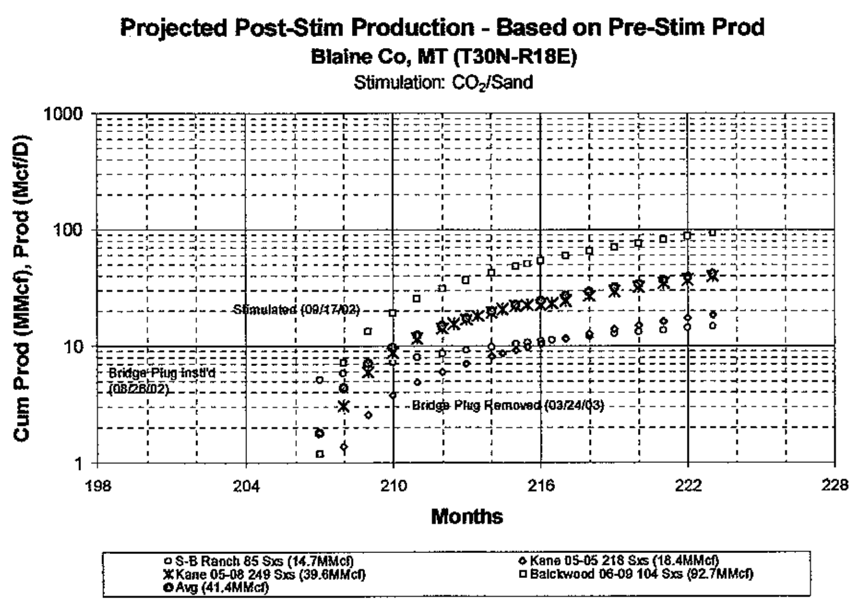
		CO_2	Sand (lbs)		Max Tr	Avg Rate	Sand Conc	
Well	# - S	Bbls	Pumped	In-Zone	Psi	BPM	Max	Avg
S-B Ranch	02-05	432	10,300	8,500	3,115	37.8	2.4	1.2
Kane	05-08	835	27,300	24,900	3,147	31.0	2.3	1.0
Kane	05-05	815	23,800	21,800	3,495	46.0	2.4	0.9
Blackwood	06-09	633	10,600	10,400	3,408	20.0	1.3	0.6

10. Results

a. Production Comparisons - Pre and Post Stimulation

(1) Pre-Stimulation

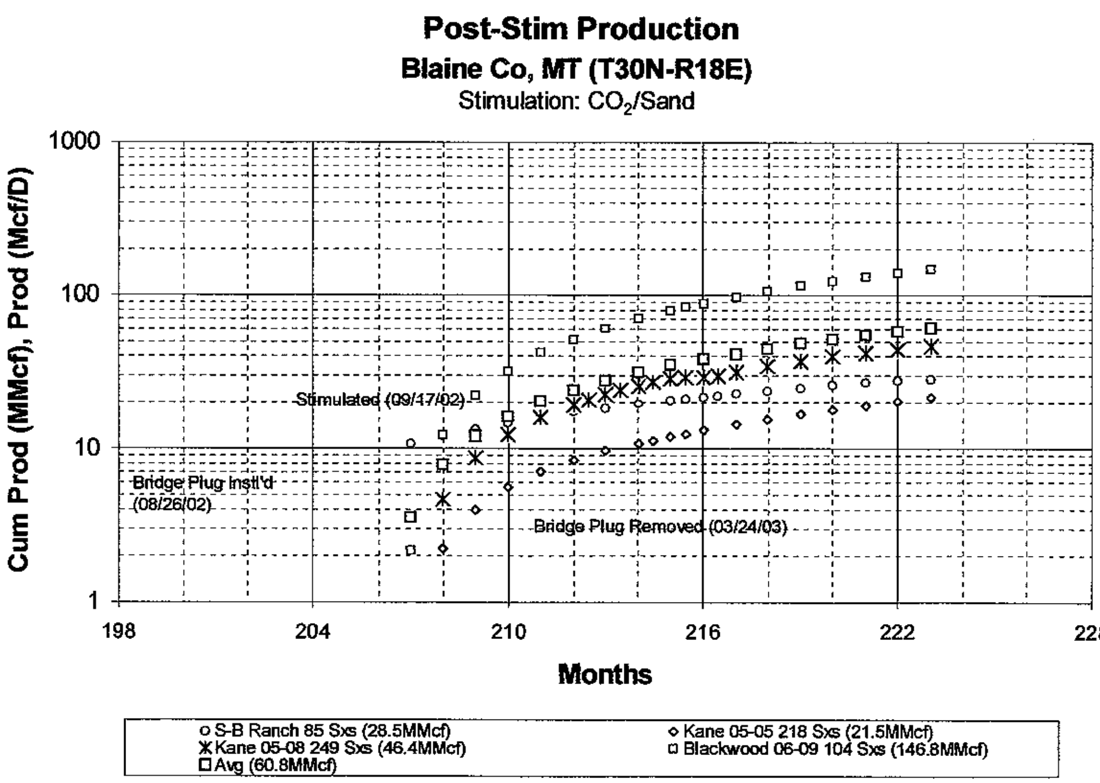
The pre-stimulation production from the four Candidate Wells was extrapolated to project the future production, and these projections served as the basis to which the production following the stimulations was compared. The projected post-stimulation volumes ranged from 14.7 to 92.7 MMcf and averaged 41.4 MMcf through July, 2004.



(2) Post-Stimulation

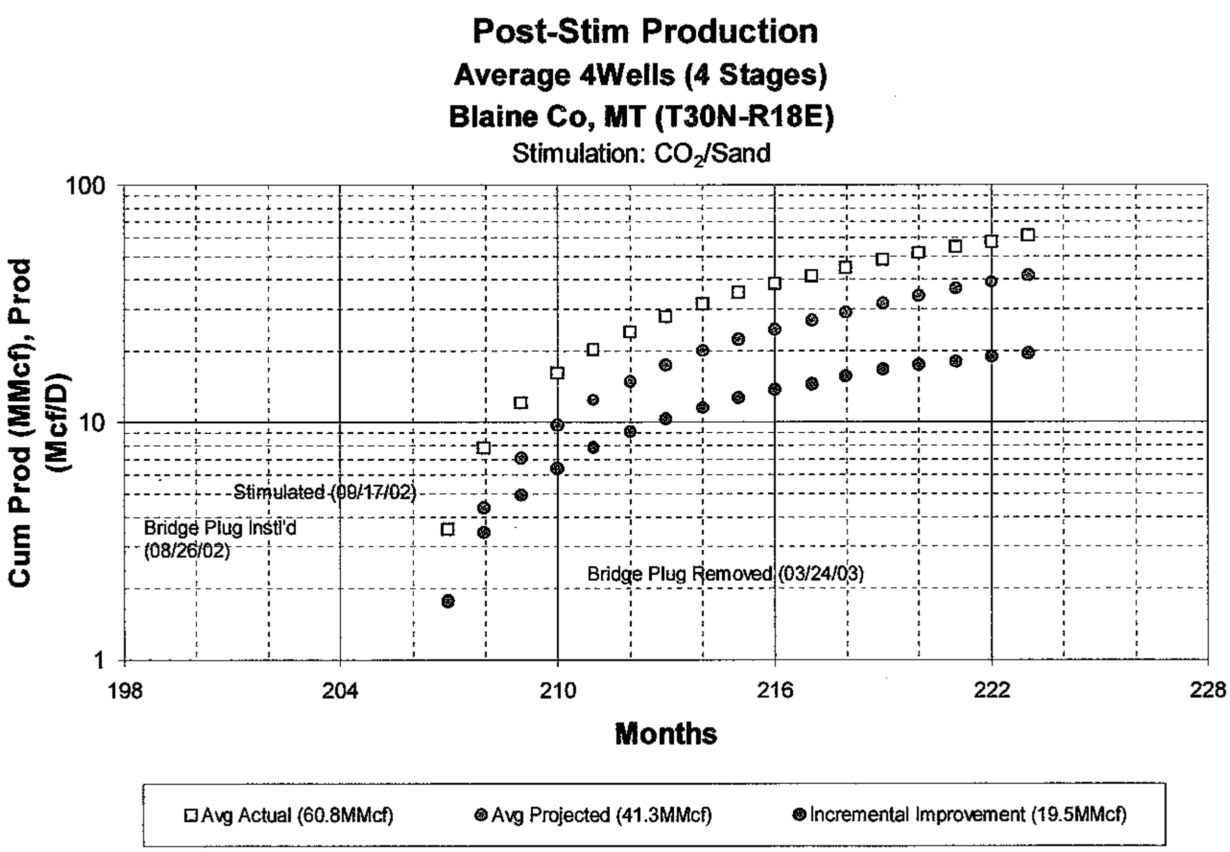
Ocean failed to provide the production data as per contract and it was obtained from public data sources (through July, 2004). The public data is reported on a monthly basis and does not include the number of producing days and therefore the production comparisons do not take into account any non-production times which results in the incremental improvements being reduced. There were known instances of non-producing periods exceeding two weeks in one of the wells and also other non-producing time intervals for all four Candidates as well.

The post-stimulation volumes for an unknown of producing days ranged from 21.5 to 146.8 MMcf and averaged 60.8 MMcf through July, 2004.



(3) Incremental Production Improvement

The incremental production improvements irrespective of the unknown number of producing days mentioned above ranged from 3.1 to 54.1 MMcf and averaged 19.5 MMcf through July, 2004.



Through July 2004

Twp/Rge	T30N/R18E	T30N/R18E	T30N/R18E	T30N/R18E	Totals
Co/St	Blaine/Mt	Blaine/Mt	Blaine/Mt	Blaine/Mt	
Field	Tiger Ridge	Tiger Ridge	Tiger Ridge	Tiger Ridge	
API Number (25-005-xxxxx)	22955	22279	22557	22161	
Surface	S-B Ranch	Kane	Kane	Blackwood	
Sec-#	02-05	05-08	05-05	06-09	
Subsequent to Bridge Plug Removal*					
Actual Post-stim Cum (MMcf)	28.5	46.4	21.5	146.8	243.2
Proj Cum (based on pre-stim prod) MMcf)	14.7	39.6	18.4	92.7	165.4
Incremental Prod Increase (MMcf)	13.8	6.8	3.1	54.1	77.8

11. Costs - Projected vs. Actual

The actual and projected costs for stimulating the four Candidate Wells were similar:

Actual Cost ($US)	63,189
Projected Cost ($US)	62,421
Difference ($US)	768
Percent (%)	1.2

12. Conclusions

The production through July 2004 (22 months) results in the following observations:

a. CO_2/Sand stimulations can be successfully pumped in the Eagle Sands.

One well, S-B 02-05 screened out with 8,500 lbs of 20/40 sand proppant in zone. The total pumped CO_2 volume was 432 Bbls. Subsequently the pad volume was increased and the wells were treated with available CO_2 volumes.

b. The in-zone placement of proppant was proportional to the pumped CO_2 volume:

		CO2	Sand (lbs)		Sand Conc	
Well	# - S	Bbls	Pumped	In-Zone	Max	Avg
S-B Ranch	02-05	432	10,300	8,500	2.4	1.2
Kane	05-08	835	27,300	24,900	2.3	1.0
Kane	05-05	815	23,800	21,800	2.4	0.9
Blackwood	06-09	633	10,600	10,400	1.3	0.6

c. All four Candidate Wells had production improvements which through July, 2004 (22 months following the stimulation) ranged from 3.1 to 54.1 MMcf and averaged 19.5 MMcf. The total incremental improvement is 77.8 MMcf.

Twp/Rge	T30N/R18E	T30N/R18E	T30N/R18E	T30N/R18E	Totals
Co/St	Blaine/Mt	Blaine/Mt	Blaine/Mt	Blaine/Mt	
Field	Tiger Ridge	Tiger Ridge	Tiger Ridge	Tiger Ridge	
Surface	S-B Ranch	Kane	Kane	Blackwood	Total
Sec-#	02-05	05-08	05-05	06-09	
Subsequent to Bridge Plug Removal*					
Actual Post-stim Cum (MMcf)	28.5	46.4	21.5	146.8	243.2
Proj Cum (based on pre-stim prod) (MMcf)	14.7	39.6	18.4	92.7	165.4
Incremental Prod Increase (MMcf)	13.8	6.8	3.1	54.1	77.8

d. One well, Blackwood 06-09, accounts for the majority – 70% (54.1/77.8) of the incremental production increase.

e. When compared with the criteria for success only one of the four Candidate Wells, Blackwood 06-09 exceeded the production criteria.

Surface	S-B Ranch	Kane	Kane	Blackwood	Total
Sec-#	02-05	05-08	05-05	06-09	
Yr 1					
Production (MMcf)	17.7	35.4	16.3	103.4	172.8
Success Criteria (MMcf)	25.2	47.6	33.1	90.4	196.3
Difference (MMcf)	-7.5	-12.2	-16.8	13.0	-23.5
Yr 1 + 10 Months (Through July 2004)					
Production (MMcf)	28.5	61.0	28.8	194.2	312.5
Success Criteria (MMcf)	43.1	83.0	53.5	161.7	341.3
Difference (MMcf)	-14.6	-22.0	-24.7	32.5	-28.8

f. When comparing the success criteria for the group of four Candidate Wells the actual production volumes are less than the established success criteria by approximately 25 MMcf.

g. The economic benefit derived from the liquid CO_2/sand stimulations based on a net of \$3.50/Mcf after 22 producing months exceeded the total treatment costs by \$19,500.

Surface	S-B Ranch	Kane	Kane	Blackwood	Total
Sec-#	02-05	05-08	05-05	06-09	
Subsequent to Bridge Plug Removal*					
Actual Post-stim Cum (MMcf) **22 Months**	28.5	46.4	21.5	146.8	243.2
Proj Cum (based on pre-stim prod) (MMcf)	14.7	39.6	18.4	92.7	165.4
Incremental Prod Increase (MMcf)	13.8	6.8	3.1	54.1	77.8
Incremental Revenue Improvement @ \$3.50/Mcf (\$M)	48.3	23.8	10.9	189.4	272.3
Stimulation Cost (\$M)	63.2	63.2	63.2	63.2	252.8
Improvement (\$M)	-14.9	-39.4	-52.3	126.2	19.5

XII. CONCLUSIONS

A. Test Area #1 - Crockett Co, Tx – Package #'s 1A & 1B - 9 Stages / 6 Wells

1. With one exception, all nine stages, six on the Montgomery lease and three on the Hatton leases were rate-limited to approximately 40-43 barrels per minute because of the maximum allowable wellhead treating pressures.. Forty barrels per minute is approaching the minimum injection rates to reliably transport 20/40 size sand proppant.

2. The production from the Candidate Wells was disappointingly low:

   a. Test Area #1A - Block NG (Montgomery)
   The projected five year cumulative production averaged 100.4 MMcf while that from the seven Control Wells averaged 745.0 MMcf or 7.4 times that from the wells stimulated with the liquid CO_2/sand process.

   b. Test Area #1A Block MM (Hoover)
   The projected five year cumulative production averaged 56.7 MMcf while that from the ten Control Wells averaged 200.3 MMcf or 3.5 times that from the wells stimulated with the liquid CO_2/sand process.

      (1) These poor responses from the wells stimulated with the CO_2/sand process are unquestionably related to a number of factors regarding the formation characteristics of permeability, and pressure, <u>but to a larger extent to the reduced proppant volumes placed by the liquid-free treatments</u>.

      (2) The placed proppant volumes with the CO_2/sand process were much lower than the design volumes.

c. Test Area #1B - Block MM (Hoover)

(1) The proppant volumes placed were much less than the design and ranged from 5,600 to 11,700 pounds or approximately twelve percent of that placed in conventional treatments.

(2) The ability to place the design quantities was obviously limited by:

(a) The reduced pump rate of 40 barrels per minute, which was driven by a maximum well head pressure of 6,500 psi.

(b) High leak off rates into the formation.

(3) The costs for the CO_2/sand stimulations (6 wells - 9 stages) was \$407,462 or \$45,274 per stage. Cost advantages resulted from a major reduction in pumping costs through the utilization of a locally available service company, Halliburton Energy Services (HES). The original bid was much greater and also required a significant mobilization charge. To a lesser extent, a cost savings for CO_2 of \$7,380 was realized by utilizing another supplier.

3. Summarizing, the conclusion is that fracture lengths longer than those which can be generated with CO_2/Sand stimulations are required in this area. It is too "tight".

B. **Test Area #2** - San Juan Co, NM - Package # 2 – 3 Stage / 3 Wells

1. The projected five year cumulative production ranged from the three Candidate Wells ranged from 65.3 to 141.9 MMcf and averaged 91.3 MMcf while that from the six Control Wells ranged between 15.6 and 445.2 MMcf averaging 231.3 MMcf or 2.5 times that from the wells.

2. These poor responses from the wells stimulated with the CO_2/sand process are unquestionably related to a number of factors regarding the formation characteristics of permeability, and pressure, <u>but to a larger extent to the reduced proppant volumes placed by the liquid-free treatments</u>

C. **Test Area #3** - Phillips Co, Mt - Package # 5 – 3 Stages / 3 Wells

1. Full proppant volume (40,000 pound) CO_2/sand stimulations were easily executed in the Phillips Sand in the Phillips Co, Montana test area

2. The production from the Candidate Wells failed to meet those required by the criteria for success.

3. The twenty-four month cumulative production volumes from the wells stimulated with the liquid-free CO_2/sand process are essentially the same as that from the Control Wells treated with N_2 Foam and utilizing the same 40,000 pound proppant volume.

4. There is a suspicion that the wells which were stimulated with CO_2/sand are being choked by limited conductivity in the hydraulically created fracture, probably as a consequence of the smaller proppant size used (20/40 vs. 12/20). This is based on the observation of the nearly identical monthly production volumes from all three Candidate Wells. And, also on the production comparisons of twenty nearby wells which utilized larger proppant.

D. **Test Area #4** - Blaine Co, Mt - Package # 7 – 4 Stages / 4 Wells

1. CO_2/Sand stimulations can be successfully pumped in the Eagle Sands.

2. The in-zone placement of proppant was proportional to the pumped CO_2 volume:

3. All four Candidate Wells had production improvements which through July, 2004 (22 months following the stimulation) ranged from 3.1 to 54.1 MMcf and averaged 19.5 MMcf. The total incremental improvement is 77.8 MMcf.

4. One well, Blackwood 06-09, accounts for the majority – 70% (54.1/77.8) of the incremental production increase.

5. When compared with the criteria for success only one of the four Candidate Wells, Blackwood 06-09 exceeded the production criteria.

6. When comparing the success criteria for the group of four Candidate Wells the actual production volumes are less than the established success criteria by approximately 25 MMcf.

7. The economic benefit derived from the liquid CO_2/sand stimulations based on a net of $3.50/Mcf after 22 producing months exceeded the total treatment costs by $19,500.

XIII. DELIVERABLES

A. Draft and final NEPA Report, described in Task 4 - Submitted

B. Phase I Topical Report described in Task 3, including market assessment and commercialization plan - Submitted

C. Criteria for implementation of the technology, and wells-of-opportunity recommendations as required in Task 1 - Submitted

D. General field test plan and individual test plans as required under Task 4 and Task 5, respectively - Submitted

E. Stimulation treatment data as required in Task 6 - Submitted

F. 5-year production and pressure data as required in Task 7 – Submitted where available

G. Post-frac summaries of well treatment, pressure testing, and flow performance as required under Task 7 – Submitted

H. Annual topical report(s) as required for Phase II - Submitted

I. Phase II final report described in Task 7 – This document

J. Production and Pressure Records

The production and pressure records have been plotted and included in the four Final Reports which have been submitted for each approved well group, and summarized in this Report..

K. Well Data

The well data for both the Control and Candidate Wells were included with the submittal packages, and in the four Final Reports which have been submitted for each approved well group, and summarized in this Report..

L. Final Reports

1. Final Report – This document
2. Pkgs # 1A and # 1B – Submitted
3. Package # 5 – Submitted
4. Package # 7 – Submitted

These reports include all of the well specific information on all of the wells.

This completes the efforts to summarize the specifics and findings of these demonstrations of the liquid-free stimulation process. More detailed well-specific information, i.e., production plots, figures, logs, etc. relative to these efforts accompany the individual reports for each group.

Respectfully Submitted,

Ray Mazza

Raymond L. Mazza, P.E.
Project Manager

FIELD TESTING AND OPTIMIZATION OF CO_2/SAND FRACTURING TECHNOLOGY

Group #'s 1A & 1B (Crockett Co, TX) – December 1995 – Six Wells - Single & Two-Stage Treatments - UPR

Final Report

By
RAYMOND L. MAZZA

Period of Performance
October 1, 1994 – November 30, 2004

Worked Performed Under Contract No.: DE-AC21-94MC31199
"Field Testing and Optimization of CO_2/Sand Fracturing Technology"

For:
U. S. Department of Energy
National Energy Technology Laboratory
Morgantown, West Virginia

By:
Petroleum Consulting Services
Canton, Ohio

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DISCLAIMER

ABSTRACT

The demonstration of a 100% liquid free CO_2/sand stimulation process was executed on six wells (nine stages) in the Canyon Sands in Crockett Co, Texas. The process is unique in that because CO_2 is the only fluid which enters the formation and requires a specialized closed system, pressurized blender to mix up to 45,000 pounds of proppant with the CO_2. The CO_2 vaporizes at reservoir conditions and leaves a liquid-free proppant pack. Because the Canyon Sands in this area were known to be liquid sensitive, the application of the liquid-free process could result in an economic benefit. The reduced proppant volume (45,000 vs. 100 to 200,000 pounds) from that of the conventional water-based stimulations was recognized, however the reduction in formation damage from retained liquids may have resulted in a net benefit.. The design pump rates could not be achieved because of pressure limitations on the tubulars and therefore a considerable reduction in placed proppant volumes resulted. The production responses were disappointingly low as a consequence of the inability to place sufficient proppant volumes.

I. ABSTRACT

The demonstration of a 100% liquid free CO_2/sand stimulation process was executed on six wells (nine stages) in the Canyon Sands in Crockett Co, Texas. The process is unique in that because CO_2 is the only fluid which enters the formation and requires a specialized closed system, pressurized blender to mix up to 45,000 pounds of proppant with the CO_2. The CO_2 vaporizes at reservoir conditions and leaves a liquid-free proppant pack. Because the Canyon Sands in this area were known to be liquid sensitive, the application of the liquid-free process could result in an economic benefit. The reduced proppant volume (45,000 vs. 100 to 200,000 pounds) from that of the conventional water-based stimulations was recognized, however the reduction in formation damage from retained liquids may have resulted in a net benefit.. The design pump rates could not be achieved because of pressure limitations on the tubulars and therefore a considerable reduction in placed proppant volumes resulted. The production responses were disappointingly low as a consequence of the inability to place sufficient proppant volumes.

II. INTRODUCTION

The first demonstrations under the contract were executed in December, 1995 in two characteristically separate groups each containing three wells. They all produce from the Canyon Sands at depths ranging from 6,428 to 7,420 feet in the Val Verde Basin of South Texas. The production is primarily gas with minimal condensate - approximately one barrel per million cubic feet of gas (1 bbl/MMcf).

A total of nine stimulations were performed in six Candidate Wells, three two-stage (Block NG), and three single-stage treatments (Block MM). All six wells are situated in Crockett County near the town of Ozona and are operated by Union Pacific Resources (UPR) formerly Union Pacific Resources Corporation (UPRC). They have since been purchased by Anadarko Petroleum.

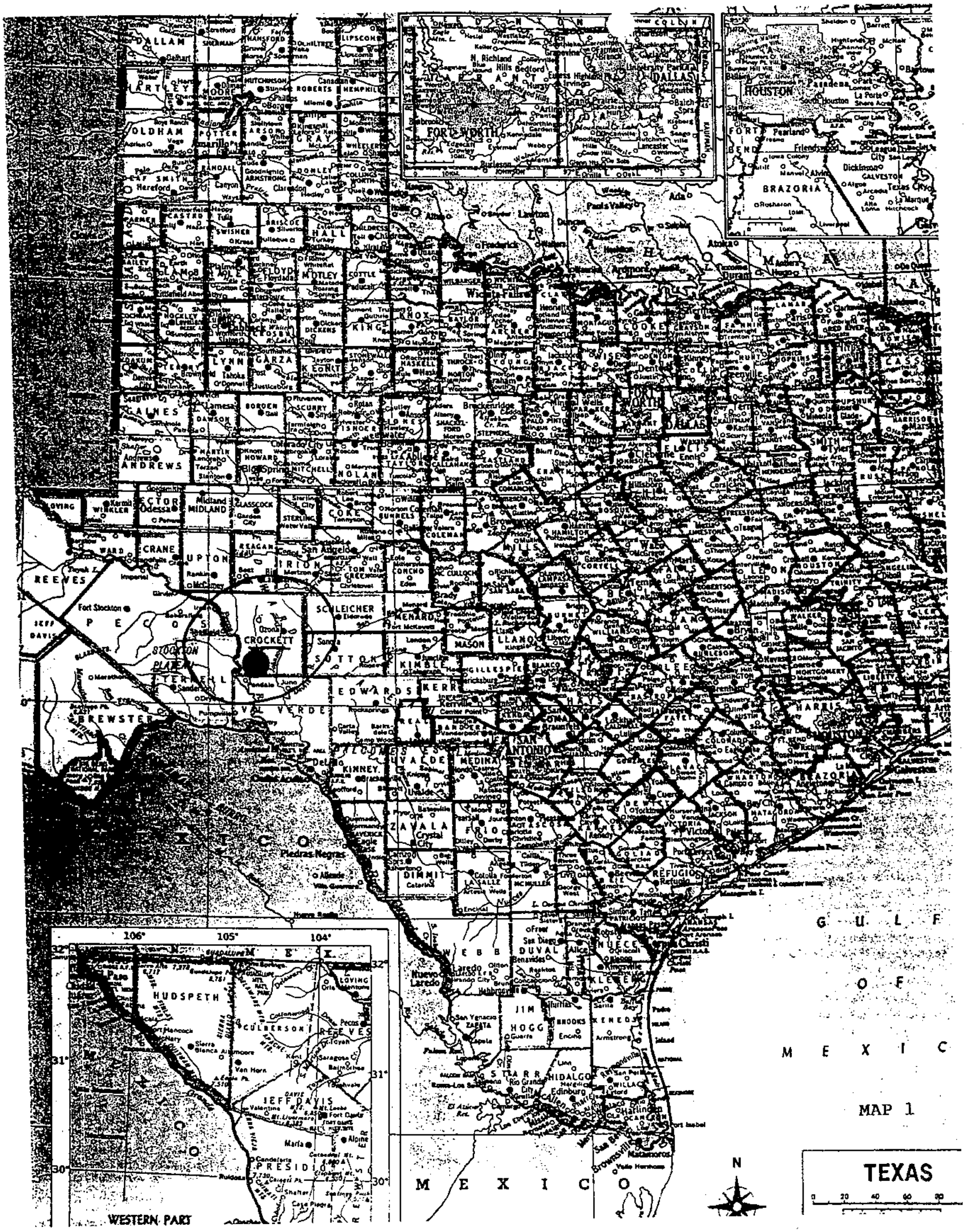
III. BACKGROUND

In 1923 World Oil Co., owned by Chester R. Bunker, Ft. Worth publisher and printer, began drilling on the L. P. Powell ranch. Work progressed slowly, depending on the availability of money, under the direction of superintendent Mickey Green and the tool pusher known only as "Dangerous Dan." The wildcat operation proved successful in the spring of 1925, when the first well (10 mi. NW) came in at a depth of 2647 feet and began producing 25 barrels of oil a day. The strike opened up the World pool, more commonly known as the Powell Field, which is still yielding oil. Eventually 180 wells were drilled by a number of companies on Powell's 9260 acre ranch.

The Powell No. 1 was the beginning of a vital new industry for Crockett County, which was primarily a ranching area before 1925. The next important strike occurred in the Crockett Field in 1938. In 1975 there were over 2,000 producing oil and gas wells in the county.

The Ozona field was initially developed in the 1960s on 320 acre spacing which was later reduced to 160, then 80, and eventually 40 acres. UPR acquired in excess of 1,000 of 1,500 wells and 100,000 net acres in April, 1994, and had drilled more than 300 wells on 80 acre spacing since the acquisition. In late 1995 approvals were obtained to drill on 40 acre spacing in the majority of the field, resulting in an additional 400 to 600 wells planned for 1996-97.

The infill wells, drilled on 80 acre spacing had reduced pressures, 50 to 80 percent of those drilled on the 320 acre spacing, consequently the recoverable reserves were also reduced.


TEXAS
MAP 1
N
G U L F
O F
M E X I C
M E X I C O
CROCKETT
PECOS
SCHLEICHER
SUTTON
VAL VERDE
TERRELL
UPTON
REAGAN
IRION
CRANE
REEVES
BREWSTER
HUDSPETH
CULBERSON
JEFF DAVIS
PRESIDIO
WESTERN PART
HOUSTON
BRAZORIA
FORT WORTH
DALLAS
Ozona
Fort Stockton
San Angelo
Piedras Negras
Laredo
Brownsville
106°
105°
104°
32°
31°
30°

The majority of the wells have tubing to remove liquids. There were no separators nor tanks and there was reportedly no produced water (some of the Candidate Wells were found to produce water), only condensate at approximately one barrel per million cubic feet of gas (1 bbl/MMcf). The gas and associated liquid is pipelined to a central stripping/compressor facility several miles distant. There are no separators nor pipeline drips.

IV. METHODOLOGY

The produced gas volumes from the Candidate Wells were compared with that from the Control Wells to determine if there was a benefit from the liquid-free stimulations over that of the other stimulation types: borate cross linked or HPC gel containing 100-200 thousand pounds of 20/40 mesh proppant.

The evaluation of the produced gas was made through the use of later-time production rates which is the basis for back-extrapolation to the earlier times in the producing life. This technique results in an uninterrupted production sequence, and thereby eliminates the unknowns associated with shut-ins, missing data, higher production rates resulting from the pressure build-up associated with shut-ins, etc. It also, and perhaps more significantly enables an unencumbered assessment to be made in that it removes the bias created by the higher rate "flush" production rates frequently recorded early in the producing life. The flush production is a result draining the more permeable portions of the formation which can be increased by the presence of natural fractures. Because these fractures are of unknown volume the flush production associated with them cannot be determined. By removing this bias the stimulation response to the unfractured portions can be evaluated, and an objective assessment of the reservoir response to the different stimulation techniques will at least not be biased by the flush production.

The projected five-year, steady-state cumulative gas volumes from the Candidate Wells were compared with those from the Control wells, and those with the larger cumulative produced gas volumes were considered to be superior.

V. GEOLOGY

The Canyon Sands are complex deep water turbodite deposits that contain numerous gas productive members with perforated intervals ranging in depth from 6,428 to 7,420 feet in the Candidate Wells. The Canyon Sands interval is approximately 1,200 feet thick and contain eight individual sand members which are designated A (shallowest) through H, and some may not be present in offset wells. Consequently the perforated intervals vary. Because of this variation the per-well reserves can vary considerably within an area and range from 0.2 to 1.2 billion cubic feet (Bcf) of gas. The permeability's range from 0.001 to in excess of 0.10 millidarcy.

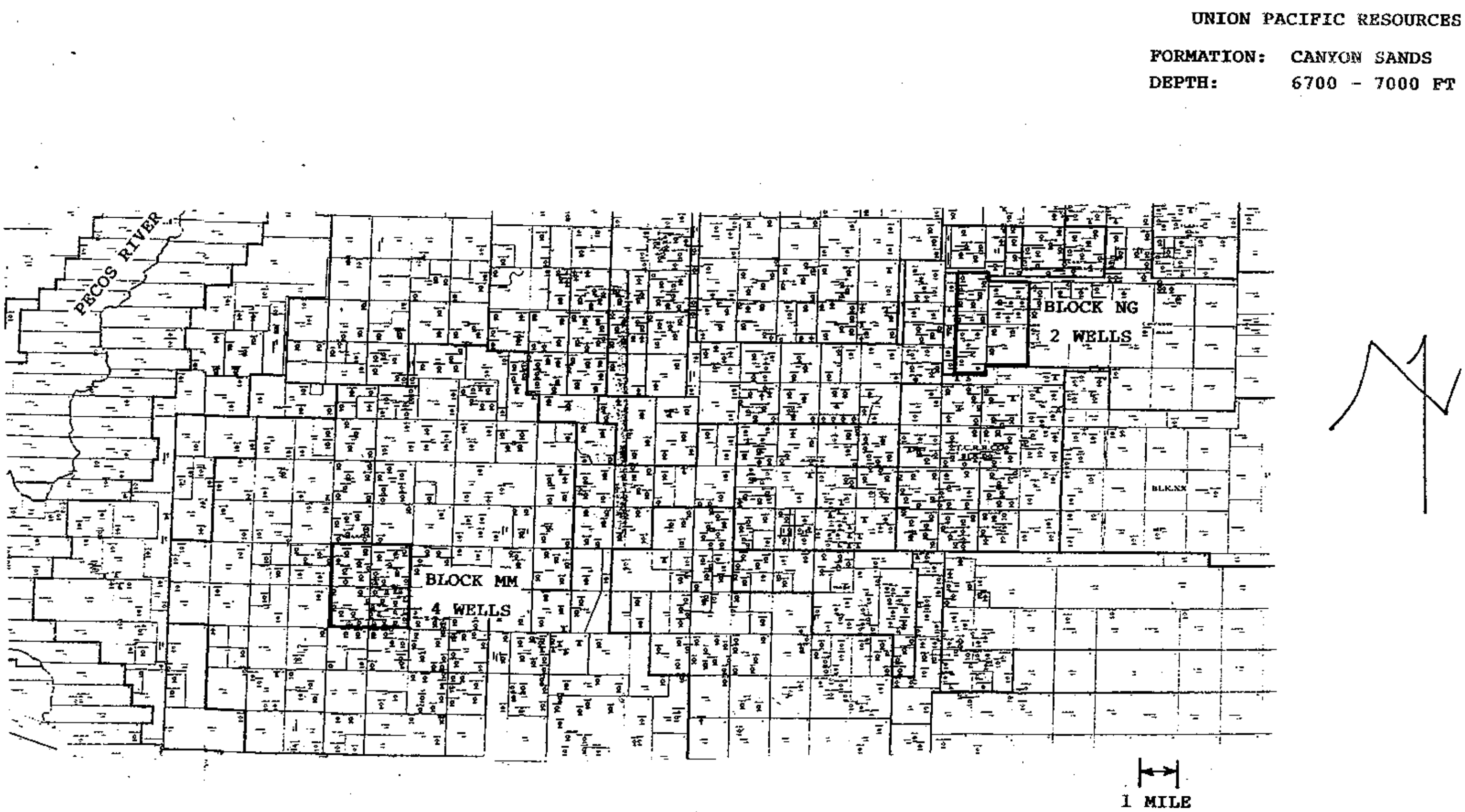
Historically, a number of these sand members were stimulated and the production co-mingled. The unique combination of the zones within individual wells complicated attempts at fracture analysis. Numerous studies performed by UPR were unsuccessful in identifying a relationship between treatment size (proppant volume) and the post-fracture well performance.

The Canyon Sands are known for the capillary retention of liquids and these Candidate Wells were considered to be good candidates for demonstrating the liquid-free CO_2/Sand technology.

VI. FIELD

Two separate areas were treated, Block NG, were stimulated in the lower (E) and middle (C) Canyon Sand members with two stage treatments, and Block MM 18 miles to the northwest with single stage treatments in lower G & H Canyon Sand intervals.

Map 2


UNION PACIFIC RESOURCES
FORMATION: CANYON SANDS
DEPTH: 6700 - 7000 FT
PECOS RIVER
BLOCK NG
2 WELLS
BLOCK MM
4 WELLS
1 MILE

VII. RESERVOIR

A. Reservoir Pressure and Temperature

Well	Press (psig)	Temp (°F)	Total Depth (ft)
Hatton 13-14	760*	182	7,515**
Hoover 7C-7	760*	155	7,585
Hatton 8C-4	760*	181	7,613
* Calculated			
** The total depths are deeper than the lowermost perforation; for instance the deepest perforation in the Hoover 7C-7 well is 7,420 feet.			

The pipeline pressure is approximately 500 psi. A review of the phase behavior at these temperatures and pressures confirmed that the CO_2 would vaporize under these conditions.

The accompanying pressure-enthalpy diagram indicates the projected states of the CO_2 during the pumping, flow back, and producing events. The CO_2 will readily vaporize under these conditions and will require -176 x $(10)^3$ BTUs per ton.

Pt # Location	Press (psi)	Temp (°F)	State	Density (lb/cuft)	Enthalpy BTU/lbm
PUMPING*					
1 Well head	6,200	0	SC	67.11	-3,900
2 Perfs	9,550	91	SC	64.52	-3,864
NOT PUMPING					
3 Perfs***	7,000	91	SC	62.50	-3,862
4 Formtn***	6,000	136	SC	55.87	-3,840
5 Formtn	900	181	SH	4.14	-3,750
6 Perfs	760	181	SH	5.88	-3,747
7 Well head	550	150	SH	4.17	-3,752
* Pumping through 4.50 in casing at 40 bbls per min					
** Heat gain through casing at 40 bbls per min = $278(10)^3$ BTUs (68 BTU/sqft @ LMDT = 67°F)					
*** At the instant that the pumping is terminated -3,840-(-3,752) = -88 BTU/lb = $-176(10)^3$ BTU/ton					

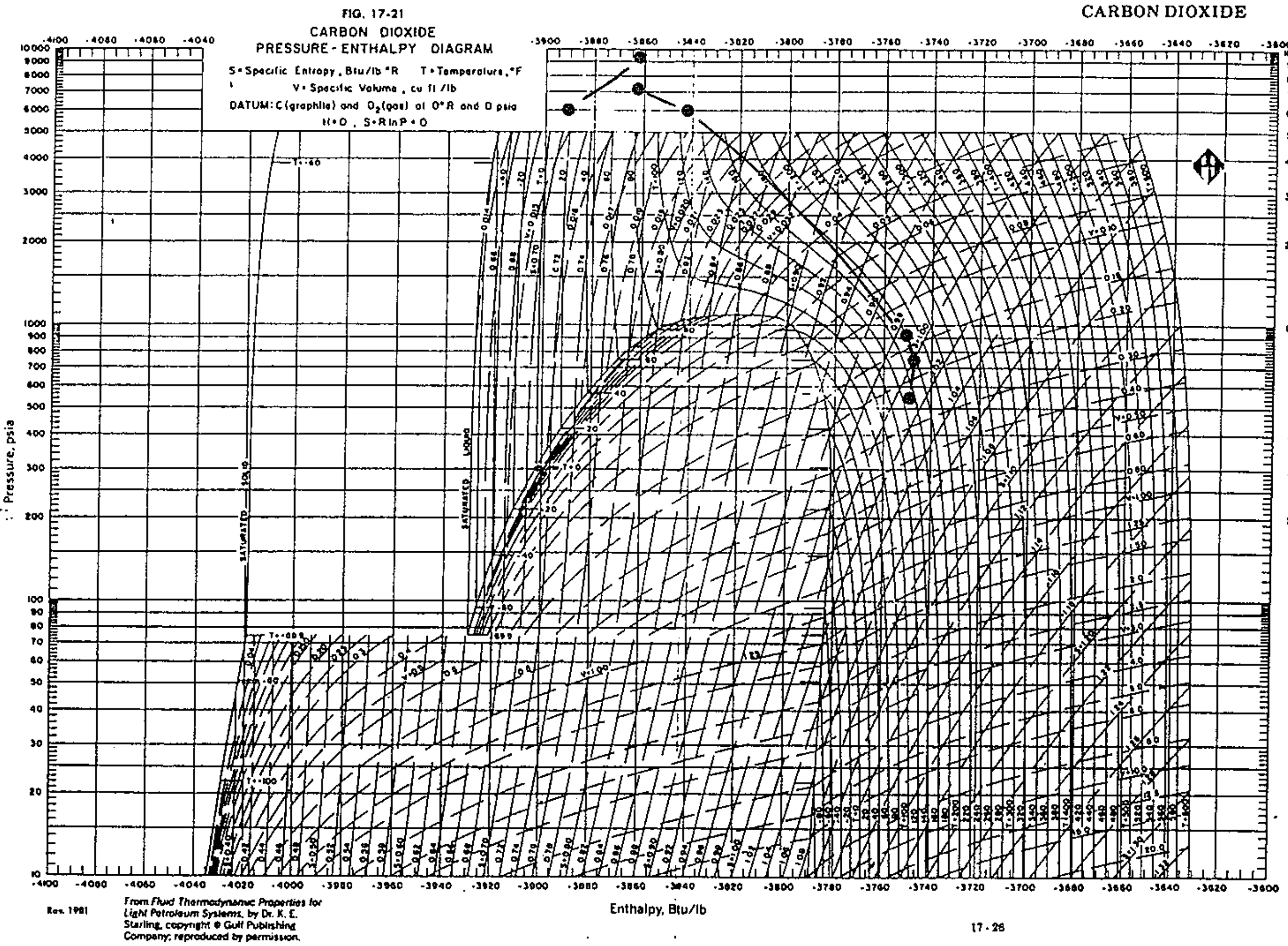


FIG. 17-21
CARBON DIOXIDE
PRESSURE - ENTHALPY DIAGRAM
CARBON DIOXIDE
S = Specific Entropy, Btu/lb °R   T = Temperature, °F
V = Specific Volume, cu ft/lb
DATUM: C (graphite) and O_2 (gas) at 0°R and 0 psia
H = 0, S = R ln P = 0
Pressure, psia
Enthalpy, Btu/lb
SATURATED SOLID
SATURATED LIQUID
Rev. 1981
From Fluid Thermodynamic Properties for Light Petroleum Systems, by Dr. K. E. Starling, copyright © Gulf Publishing Company; reproduced by permission.
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B. Sensitivity to Stimulation Liquids

The wells in these areas require some time to clean up following the liquid based stimulations and appeared to be excellent candidate opportunities for this technology.

The Canyon Sands are known for the capillary retention of liquids, and each of the two groups of three Candidate Wells were considered to be viable opportunities for demonstrating the liquid-free CO_2/Sand technology. Primarily, because of the suspicion that formation damage was resulting from the formations sensitivity to stimulation liquids, and also through the interest that UPR indicated in the process and their ability to effectively evaluate the results through their in-house knowledge and large data set.

VIII. CONVENTIONAL STIMULATION TREATMENTS

The wells in both areas were being stimulated with either borate cross-linked guar gum or HPC gels containing 100-200 thousand pounds of 20/40 mesh proppant, either Brady or Ottawa sand. Previously the treatments consisted of gelled water with sand concentrations of up to 4 pounds per gallon (ppg) or gelled acids with sand concentrations up to 3 ppg.

There were no known CO_2 based stimulations when initially proposed. However, just prior to the liquid CO_2/sand treatments performed under this demonstration effort one of the initially proposed Candidate Wells, Hatton #3-17 was stimulated by UPR, without DOE involvement, with 577 bbls (107 tons) of liquid CO_2 and because the response was so robust UPR withdrew it from the offering. Hatton 7C-7 was substituted for it.

IX. CO_2/SAND STIMULATIONS

The normal field procedure was to complete the wells with 2-7/8 inch production tubulars. However, for the purposes of this evaluation, the DOE approved Candidate Wells were completed with 4-1/2 inch production casing to enable the greater pumping rates, 40-55 barrels per minute, to be achieved without the excessive friction pressure drops associated with the smaller diameter tubulars.

A. Design

Once the project began it became obvious that the injection rates would be limited to approximately 40 barrels per minute because of maximum allowable treating pressures of 6,000 to 6,500 psi.

The individual well treatment designs were based upon sand acceptance concentrations in the offset wells and could be modified as the treatment sequence progressed. The objective being to place the maximum sand volumes. The maximum proppant concentrations at the 40 bpm pump rates were found to be less than 3 pounds per gallon.

An increase in the design CO_2 volume from 120 to 140 tons was a result of the displacement volume of 106 barrels (20.8 tons) to reach the completion interval at approximately 7,000 feet.

The stimulation designs were developed from the observed pressure-injection history for well 13-17, which was stimulated with CO_2 only and which also had 4-1/2 inch casing, as did the Candidate Wells.

The data was plotted in three representations because a log-log plot of the data was very non-linear. The first explanation considered was that it was because of differing densities experienced from the heat loss during the initial cooling of the tubulars. The densities for each rate at approximated temperatures which were time and heat transfer rate dependent were calculated and the log-log plot recreated and it was still found to be considerably non-linear.

In an effort to utilize this empirical pressure data it was plotted on linear, log-linear, and log-log presentations and the results compared. A review of the data indicated a considerable range of pressures when the injection rates exceed forty (40) barrels per minute.

Rate (BPM)	Pressure (Psi) Linear		Pressure (Psi) Log-Lin	Pressure (Psi) Log-Log
	Min	Max		
20	3,900	3,900	3,900	3,900
25	4,350	4,350	4,200	4,300
30	4,600	4,750	4,950	4,800
35	5,000	5,250	5,500	5,000
40	5,400	5,750	6,200	5,500
45	5,800	6,350	7,100	6,000
50	6,200	6,800	8,100	6,200
55	6,600		9,500	6,700
60				7,100

Based on these observations, the following injection rates were predicted for various wellhead treating pressures:

Wellhead Pressure (Psi)	Min		Max	
	Rate (BPM)	(HHP)	Rate (BPM)	(HHP)
4,000	21.1	(2,069)	21.7	(2,127)
5,000	30.5	(3,738)	35.0	(4,289)
6,000	38.6	(5,676)	47.5	(6,985)
6,500	41.7	(6,643)	53.8	(8,571)

And, the projected pump rate ranges for various horsepower's were:

HHP	Min BPM	Max BPM
3,600	29.7	30.8
4,800	34.9	37.4
6,000	39.6	42.9
6,643	41.7 (max press)	45.6
7,200	N/A	48.4

The conclusions from these projections were that:

1. Up to 6,104 horsepower would be required to obtain an injection rate of forty barrels per minute — which was considered to be a minimum rate to achieve a reasonable fracture extension and transport velocities.

2. The wellhead treating pressures for these conditions were estimated to be up to 6,226 psi.

3. Utilizing the maximum wellhead treating pressure of 6,500 psi. The corresponding minimum pump rate and horsepower requirements would be:

Min BPM	HHP
41.7	6,642

If the well was to treat at the lower pressure scenario then the pump rate at the maximum horsepower was estimated to be 48.4 bpm.

Summarizing, the pump rate was anticipated to range from 41.7 to 48.4 barrels per minute depending upon either maximum allowable pressure limitations for the former or maximum available horsepower for the latter.

The actual treating pressures were very close to those projected as can be seen in the following summaries.

Once the project began it became obvious that the injection rates would be limited to approximately 40 barrels per minute because of maximum allowable treating pressures of 6,000 to 6,500 psi.

B. Proppant Size

20/40 (USS) sand proppant was currently being utilized in the conventional treatments and successful in the CO_2/sand stimulations, and on that basis was proposed in the design

C. Treatment Volume

The treatments were designed to consist of 140 tons of CO_2 per stage and are projected to yield a net of 439 barrels (85 tons) of CO_2 in-zone along with 37,654 pounds of 20/40 proppant per stage. The individual well treatment designs were developed based upon sand acceptance concentrations in the offset wells and were modified as the treatment sequence progressed, the objective being to place the maximum sand volumes. The increase in the CO_2 volume from 120 to 140 tons was due to the displacement volume of 106 barrels (20.8 tons) to reach the completion interval at approximately 7,000 feet. Thereby more CO_2 was available to stimulate the formation and to transport proppant.

The recommended stimulation design was:

Proppant Fluid Schedule					
	Cum Fluid	Stage Fluid	Proppant Conc	Proppant Stage	Cum Proppant
	(Bbl)	(Bbl)	(ppg)	(lb)	(lb)
Stage					
Hole Fill (Liquid CO_2)	55	55		0	0
Pad (Liquid CO_2)	135	135		0	0
Start (20/40 Sand)	205	70	1.0	2,940	2,940
Increase (20/40 Sand)	245	40	2.0	3,360	6,300
Increase (20/40 Sand)	465	220	3.0	27,720	34,020
Flush (Liquid CO_2)	575	55		0	34,020
	Total	575			

Treatment Fluid Requirements						
	Hole + Pad	Prop	Flush	Tot pmpd	Bottoms	Total
Liq CO_2 (Bbl)	190	330	55	615	10	625
CO_2 (T)						120
N_2 (Mscf)						74

D. Treatment Volume Comparison - Conventional vs. CO_2/Sand

The design volumes of the liquid CO_2 /sand stimulations was 575 Barrels of liquid CO_2 and 34,020 pounds of 20/40 mesh proppant, as compared to the conventional treatments which contain 100 to 200,000 pounds of 20/40 proppant. The proppant volume utilized in the CO_2/sand treatments - if it were all to be placed - would be 17 to 34 percent of that normally pumped.

Because of the liquid sensitive nature of the Canyon Sands the results from these reduced proppant volumes could potentially result in an improvement in gas production rates because of the absence of the liquid induced formation damage which accompanied the conventional water based treatments.

E. Perforation Strategy

The perforation placements are in the individual sand members as indicated on the accompanying electric logs.

X. PRE-TEST CONCLUSIONS

A. The Canyon Sands were known to be liquid sensitive and to sometimes require extended clean up periods, and therefore were considered to be potential candidates for the liquid-free CO_2/sand stimulation technique,

B. Studies conducted by UPR indicated that smaller treatment volumes resulted in improved production rates, which further supported the view that the larger stimulation liquid volume probably results in a larger percentage of liquid remaining in the reservoir; although the treatment volume is larger so thereby is the resultant damage.

C. If the damage created by these liquids could be avoided then the reservoir could potentially respond favorably to smaller treatments.

D. The fracturing gradients were reviewed and found to be on the order of 0.7 psi per foot and resultantly considered to be viable candidates,

E. The leak off of the CO_2 to the formation at the higher permeability's was considered to constitute a potential screen out risk,

F. The pump rate limitations dictated by the working pressure of the tubulars, 6,500 psi was predicted to limit the injection rate to approximately 40 barrels per minute. The preferred design for the permeability, formation thickness, and number of perforations would have been on the order of 55 bpm.

G. The predictably higher treating pressures were known to significantly increase the horsepower costs.

XI. CRITERIA FOR SUCCESS

The production histories for both blocks were reviewed and the economic hurdle rates projected for each. The minimum production rates for an economic success of these treatments are based upon the reservoir pressure and the additional expense associated with the CO_2/Sand stimulations.

Area	1 (Montgomery)	2 (Hoover-Hatton)
Block	NG	MM
Stages/well	2	1
Treatment Costs		
CO_2/Sand ($)	82,684	41,509
Conventional ($)	40,000	21,000
Increase ($)	42,684	20,509
Incremental Prod		
Req'd @ i=15% (Mcfd)	25	12
Presently (Mcfd)	150-200	125-180
Min Req'd - 1st Mo w/ CO_2/Sand (Mcfd)	175-225	137-192

The minimum production rates for an economic success of the CO_2/Sand stimulations technology were:

Block	
NG	MM
175-225 Mcfd	125-180 Mcfd

UPR initially estimated that an increase in production rate of approximately 20 percent will be required to offset the additional costs of the CO_2/Sand stimulation. On this basis, a production rate of 137 to 192 Mcfd would be required to demonstrate superiority of CO_2/Sand stimulation treatments over nitrogen foam stimulations in this area.

XII. IS THE PROPOSED RESERVOIR LIKELY TO BENEFIT FROM THE CO_2/SAND TECHNOLOGY?

A. Operator

1. Interest in CO_2/Sand technology?

UPRC was interested in identifying a stimulation technique which would reduce or eliminate the liquid damage to the Canyon Sands and, in addition to stimulating 12 stages with CO_2/Sand they also elected other types of stimulation treatments - three wells with CO_2 only, and four with Econofracs which utilized 10 to 25 pounds of linear gels per thousand gallons of water and transporting 1-2 pounds per gallon of sand.

2. Adequate test opportunity?

The question was: Would a non-damaging stimulation having a shorter propped length be more effective than a longer hydraulically created fracture that utilizes a formation damaging liquid? Ultimately, the answer was no.

The possibility of stimulating this liquid sensitive reservoir with the non-damaging CO_2/Sand stimulation process was viewed as an opportunity to evaluate the effectiveness of a non-damaging, but shorter fracture length stimulation. The potential that the non-damaging treatment could perhaps provide an increase in overall economics was a determining element in the decision to participate in the program. i.e., could a smaller treatment (shorter fracture length) created with a non-damaging fluid result in an increased production rate over that which resulted in longer fracture lengths and liquid damage?

Ultimately, the answer was no.

3. Presently active drilling program?

   When the review of the potential Candidate Wells began, UPR had eight rigs drilling the 6,500 feet deep Canyon horizon, and were planning to drill over 600 wells during the 1995-1997 time period.

4. Control wells - Is there a sufficient number to define a normal response?

   UPRC had digitized over 600 well logs and conducted reservoir simulation and analytical drainage area studies on more than 500 wells. They had also conducted numerous pre- and post-fracture build up tests, conducted in-situ stress tests, and have estimated the reserves for at least 1,500 Canyon Sand wells. This familiarity enabled an objective assessment of the different stimulation types to be rendered.

5. Is there a future for successful results? Is the operator likely to continue implementing this technology without DOE cost support?

   The Canyon Sands were being actively drilled with the more recent developments in areas of reduced porosity, permeability, and reservoir pressure which resulted from the closer well spacing. These "tighter and reduced reservoir pressure" areas were anticipated to be compromised by the retention of the liquids used in hydraulic fracturing and the potential for increased gas recovery which could result from the non-damaging stimulation was considered to be significant.

<u>UPSIDE</u> - Future Activities if an Economic Success were to be Realized

If the CO_2/Sand stimulation technology proved to be successful in increasing the EUR's over other stimulation treatment types, then a significant upside would be created because of the areal extent of the impacted area and UPRC's immediate development drilling plans. They were actively drilling the Canyon Sands formation in Crockett County, Texas - SW Ozona Field and considered them to be ideal candidates for the CO_2/Sand demonstrations.

6. Interest in DOE cost-supported participation?

   An interest in participating with the DOE on a cost shared basis to evaluate this technology was related. At the time they planned to drill approximately 300 wells per year for the following two to three years, and had seven to eight drilling rigs operating in this area.

7. Share production data for five years?

   UPRC agreed to share the data. In actuality they did not. UPR was later purchased by Anadarko and the production data was obtained from public data sources.

8. Letter of Intent

   A Letter of Intent was prepared and executed (LOI).

   - To provide legitimate candidate well opportunities for six mutually agreed upon wells,
   - To provide acceptable background information on the nearby control wells including the drilling, completion, and production specifics,
   - To bear the normal additional expenses of cement bond logging, perforating, bull dozers, and other normally occurring expenses associated with stimulation events,
   - Participating in the demonstration project and the anticipated treatments specifics, and
   - To provide the production information for five years.

Letter of Intent
(p. 1 of 2)

Operator: Union Pacific Resources Co (UPRC)

Candidate Wells: Crockett County, Texas

Target Formation: Canyon Sands

Block MM (Hoover Hatton)

	Sec	1/4	OF	1/4	Sands	Stages	1st Mo Prod*
1. 7C-7 (exch for 13-17)	7	SE		SE	G & H	1	137-192 Mcfd
2. 8C-4	8	SW		SE	" " "	1	" " "
3. 13-14	13	SW		NW	" " "	1	" " "
13-17	13	SW		NE	" " "	N/A	

Block NG (Montgomery)

	Sec	1/4	OF	1/4	Sands	Stages	1st Mo Prod*
1. 12	18	Irregular			C & E	2	175-225 Mcfd
2. 13	18	" "			" " "	2	" " "
3. 15	18	" "			" " "	2	" " "
						9	

* Minimum 1st month average production required from CO_2\sand stimulations to constitute an economic success over that from conventional stimulations, with nitrogen foam.

The U. S. Department of Energy will, subject to their approvals, agree to provide cost-shared funding for the stimulation of these candidate wells with Fracmaster's closed system blender for CO_2\sand treatments, if certain criteria are met. UPRC agrees to bear the remaining expenses.

The project entails demonstrating the process in a controlled environment where sufficient background production information from nearby wells can be used to compare the production results with those of this demonstration project.

The design of the stimulation treatments is to consist of approximately 140 tons of carbon dioxide and 25,000 to 45,000 pounds of sand pumped at injection rates of 35 to 60 barrels per minute, and to consist of up to three (3) single-stage treatments (Block MM), and up to three (3) two-stage treatments (Block NG).

UPRC agrees to operate these wells with wellhead pressures similar to those of the control wells to enable a meaningful comparison of the production from the candidate wells with that of the nearby offset control wells. The purpose is to effect a quantitative comparison of the effectiveness of the liquid-free CO_2\sand stimulation with that of nitrogen foam.

The six (6) candidate wells will be available for stimulation treatments by the second week of December, 1995.

The wells will be turned in line shortly after treatment, and the production will be forwarded to PCS on a monthly basis to enable an evaluation of the CO_2 treatments to be made. DOE is requesting monthly production data on these

Letter of Intent
(p. 2 of 2)

wells for a minimum of five (5) years following turn-in, including monthly copies of the meter run readings and third party integration statements. They are to be forwarded monthly to Petroleum Consulting Services.

Sand, if any, will be removed from the wellbore at operator's expense, immediately following the stimulation.

The DOE requires the following:

1. Executed Letter of intent — This document
2. A map of the candidate well and nearby offsetting wells - Satisfied
3. Electric logs — Control and candidate wells
4. Cumulative production data — Control and candidate wells

5. Monthly pipeline pressure data — Control and candidate wells
6. Stimulation records tabular and strip charts — Control and candidate wells
7. Well completion reports — Control and candidate wells

The DOE, subject to their approval, will, through the contractor, Petroleum Consulting Services, pay for one-half (1/2) of the costs of the stimulations, including the service company charges for product (CO_2, sand), services, and mobilization. This is to be accomplished by an invoice from UPRC to PCS for one-half (1/2) of the total stimulation costs which includes all discounts.

UPRC hereby indicates an intention to enter into a 50/50 cost-shared participation of the stimulation expenses for these candidate wells, subject to DOE approvals.

UPRC agrees to bear the remaining expenses of these treatments and any remaining activities, i.e., those expenses normally associated with these treatments: cement bond log, perforating, dozers, service rigs, etc.

If these conditions are satisfactory, please acknowledge by signing below, and returning this document to:

Petroleum Consulting Services
P. O. Box 35833
Canton, Ohio 44735
(216) 499-3823 (216) 499-2280 (fax)

Date: Dec. 8, 1995

Signed: R. J. [signature]
Company Officer
Title: W. TX. DEVELOPMENT MGR.

Witness: [signature]

XIII. NEPA COMPLIANCES

A NEPA questionnaire was prepared and submitted for the Candidate Wells. Conversations with UPRC's environmental compliance personnel and the specifics of land use, air quality, water resources/water quality, solid waste and hazardous materials, impact on vegetation and animals, aesthetics, historical/cultural resources, transportation, energy requirements, environmental restoration and/or waste management, and worker health and safety have been identified and responded to.

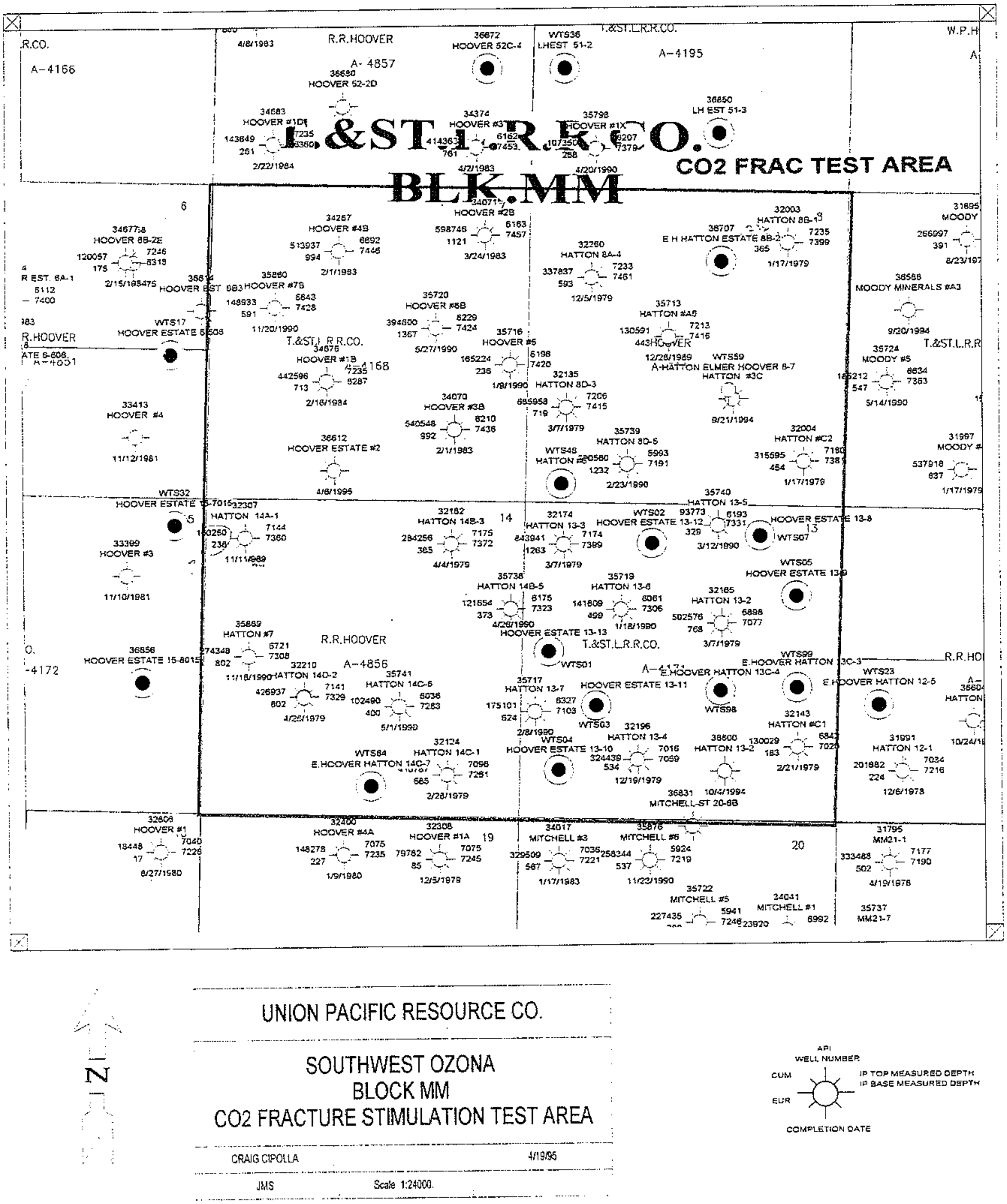
XIV. DOE APPROVALS

The six Candidate Wells, three in Block NG and three in Block MM, were submitted (05/06/95) and approved for treatment by the DOE (12/06/95) and were stimulated in December, 1995.

XV. TEST AREAS – TWO TEST AREAS – BLOCK NG and BLOCK MM

There were demonstration areas proposed, and approved for the liquid CO_2/sand stimulation process. Each contained three wells and, although both groups were producing from the Canyon Sands interval, there were distinctly different reservoir characteristics.

The major differences between the two study areas, Block NG (Montgomery) and Block MM (Hoover Hatton) are that the Canyon Sand interval in Block NG contained an increased pay thickness, and was consequently stimulated with two stage stimulations.


T.&ST.L.R.R.CO.
BLK.MM
CO2 FRAC TEST AREA
R.R.HOOVER
A-4166
A-4195
A-4857
A-4856
A-4172
UNION PACIFIC RESOURCE CO.
SOUTHWEST OZONA
BLOCK MM
CO2 FRACTURE STIMULATION TEST AREA
CRAIG CIPOLLA
4/19/95
JMS
Scale 1:24000.
N
API
WELL NUMBER
CUM
EUR
IP TOP MEASURED DEPTH
IP BASE MEASURED DEPTH
COMPLETION DATE

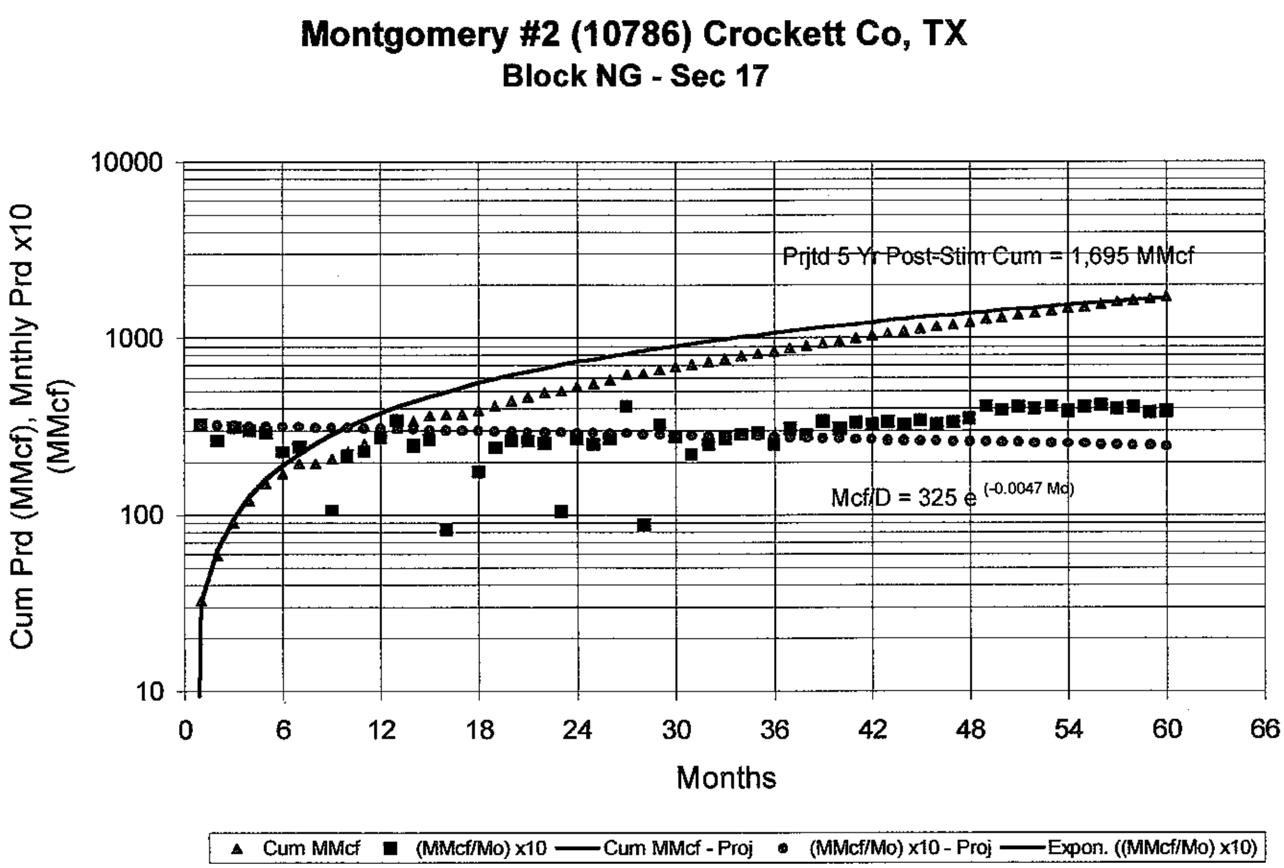
Because all of the wells are situated in Crockett County, Texas the API well identification numbers are all prefixed with 42-105. For instance the API number for the Hatton 03-13 is 42-105-32174

A. Test Area #1 - Block NG (Montgomery) - Two Stage Completions

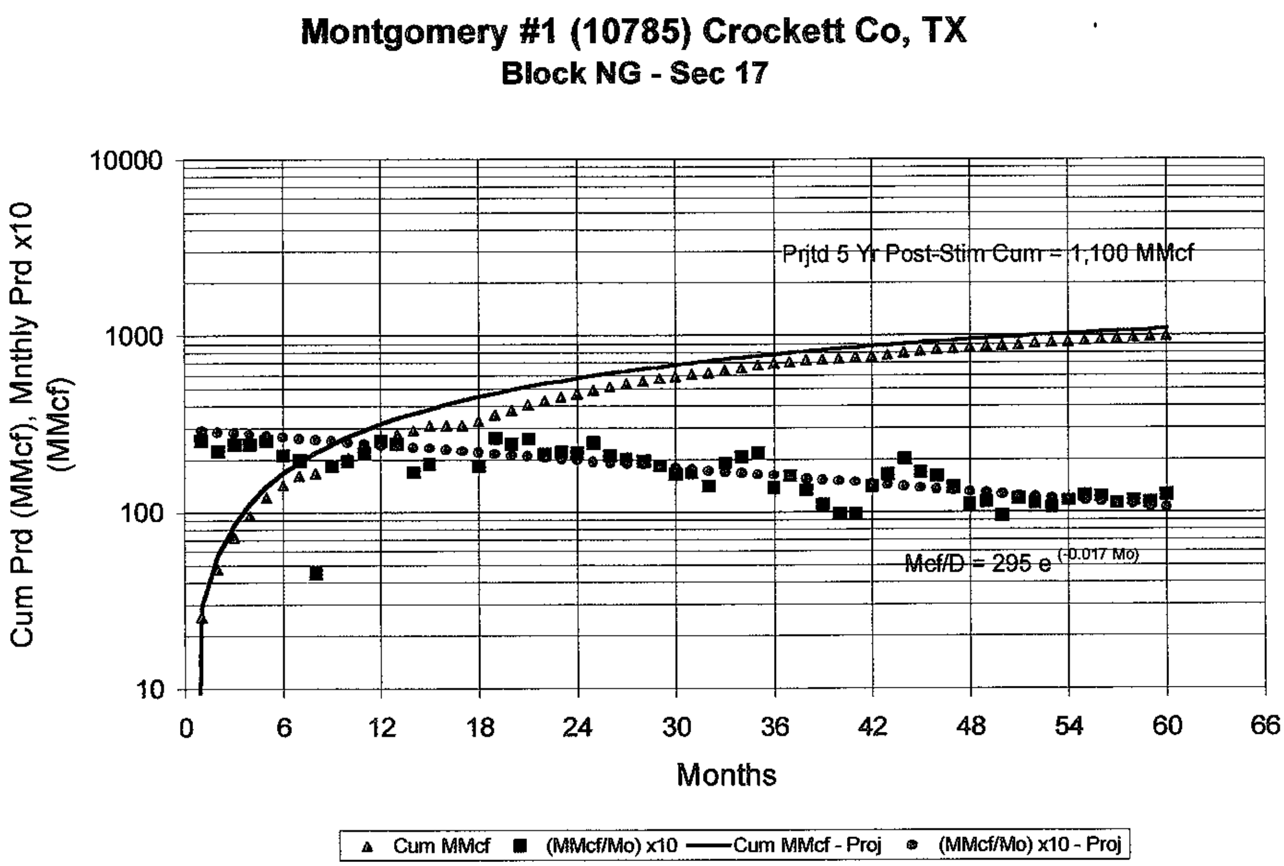
Block NG occupies approximately the same areal extent and contained seventeen active wells. The three Candidate Wells were completed in the C (Lower) & E (Middle) Sands and stimulated with two stage CO_2/sand treatments. The reservoir pressure was about 50% of the original (when they were drilled on 320 acre spacing) and the estimated ultimate recoveries (EUR's) generally range between 1,500 and 4,500 MMcf.

1. Control Wells - 7 Wells

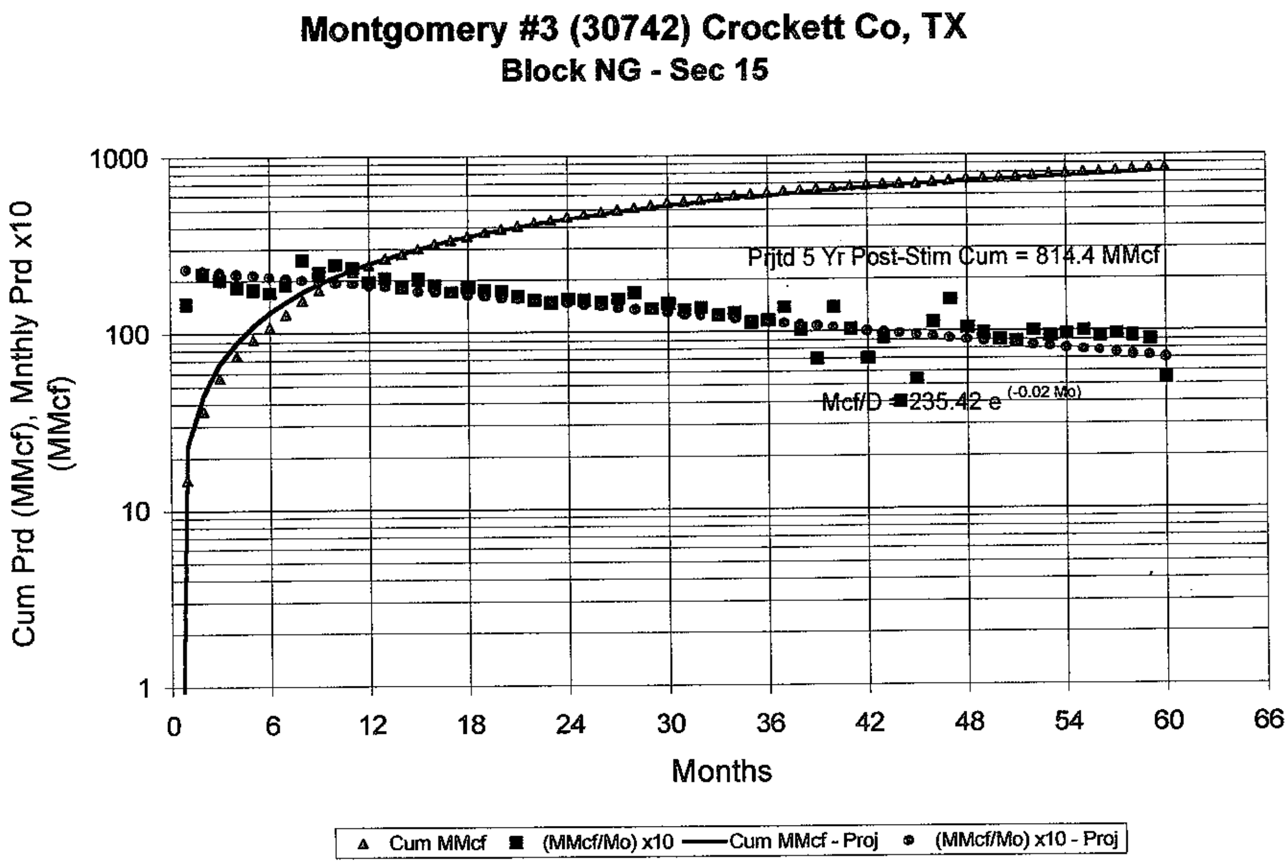
   a. Control Well # 1 – Montgomery 02-17 (10786) – Projected 5 Yr Prod 1,695.2 MMcf



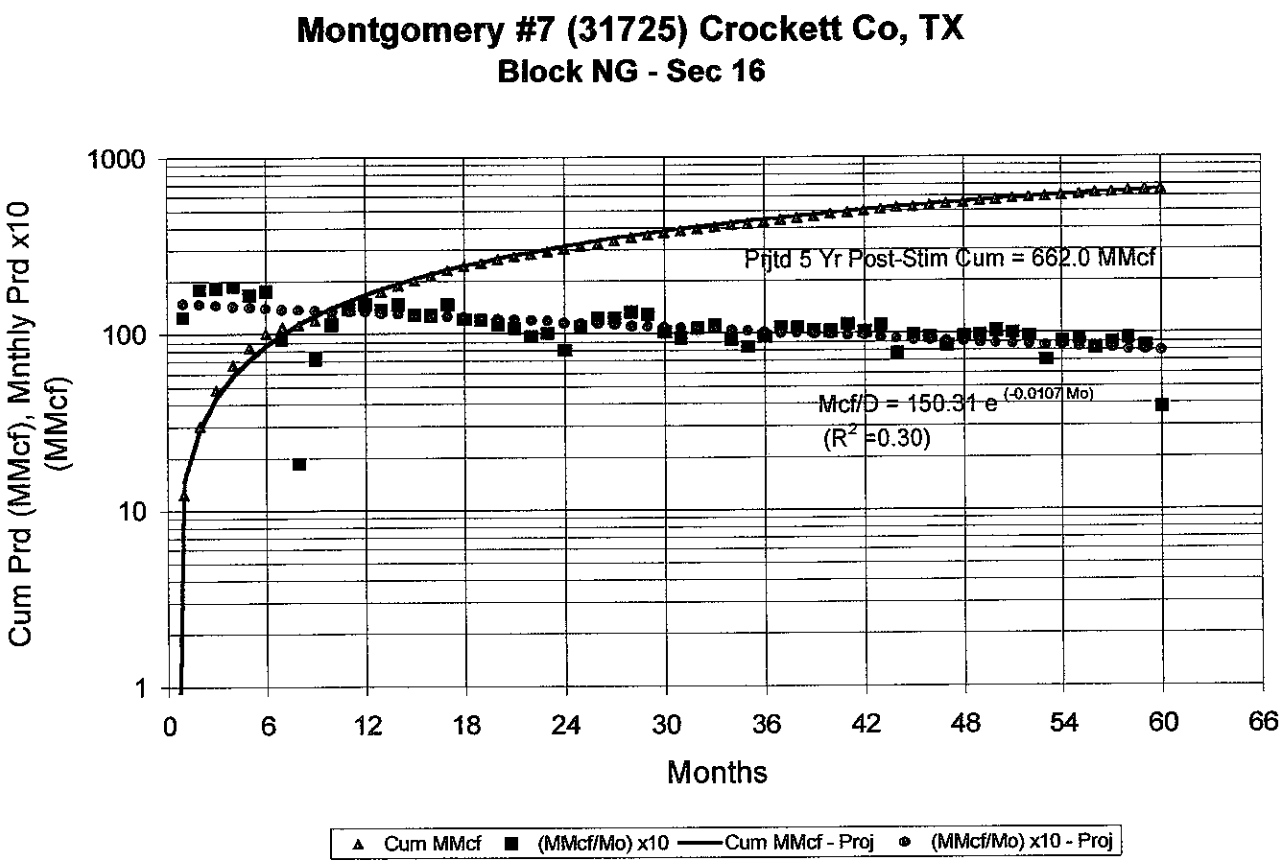
b. Control Well # 2 – Montgomery 01-17 (10785) – Projected 5 Yr Prod 1,100.2 MMcf



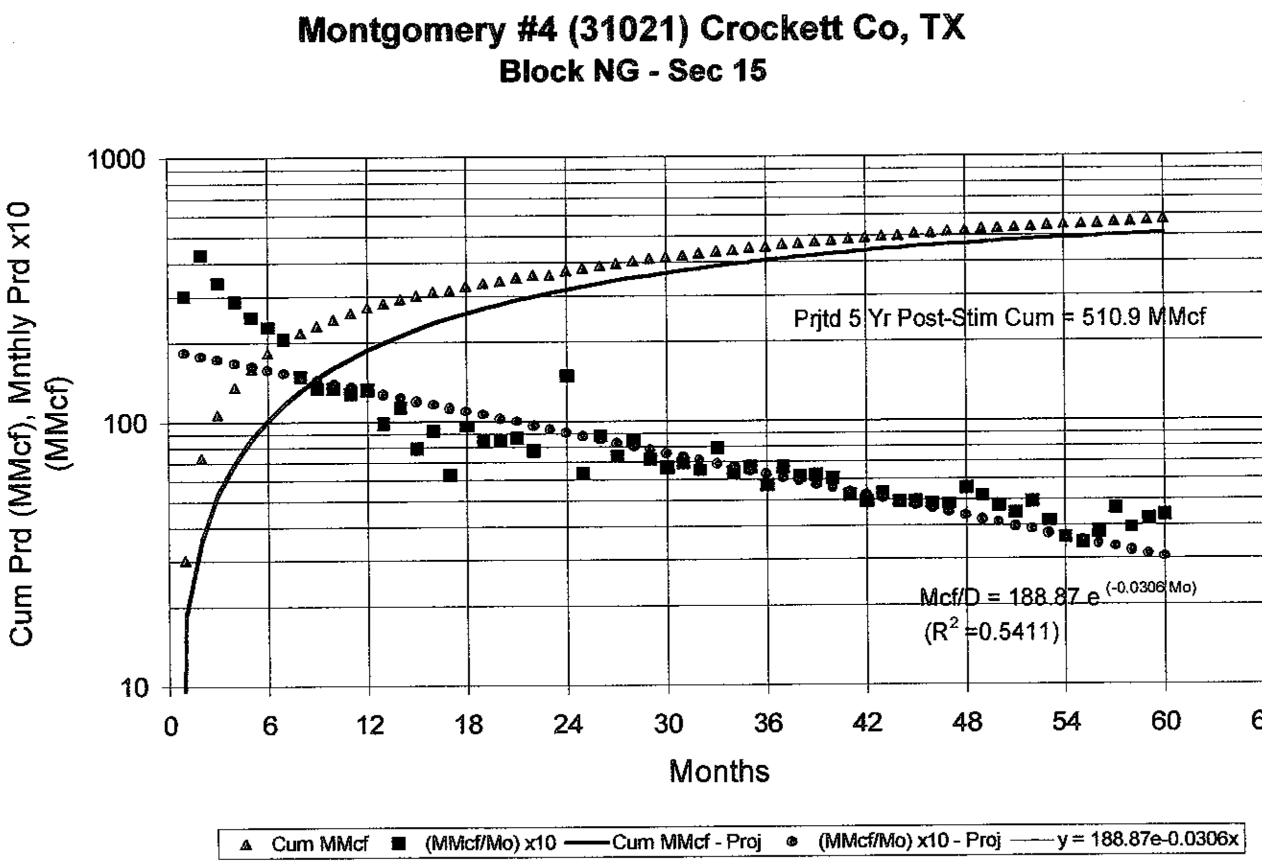
c. Control Well # 3 – Montgomery 03-15 (30742) – Projected 5 Yr Prod 814..4 MMcf



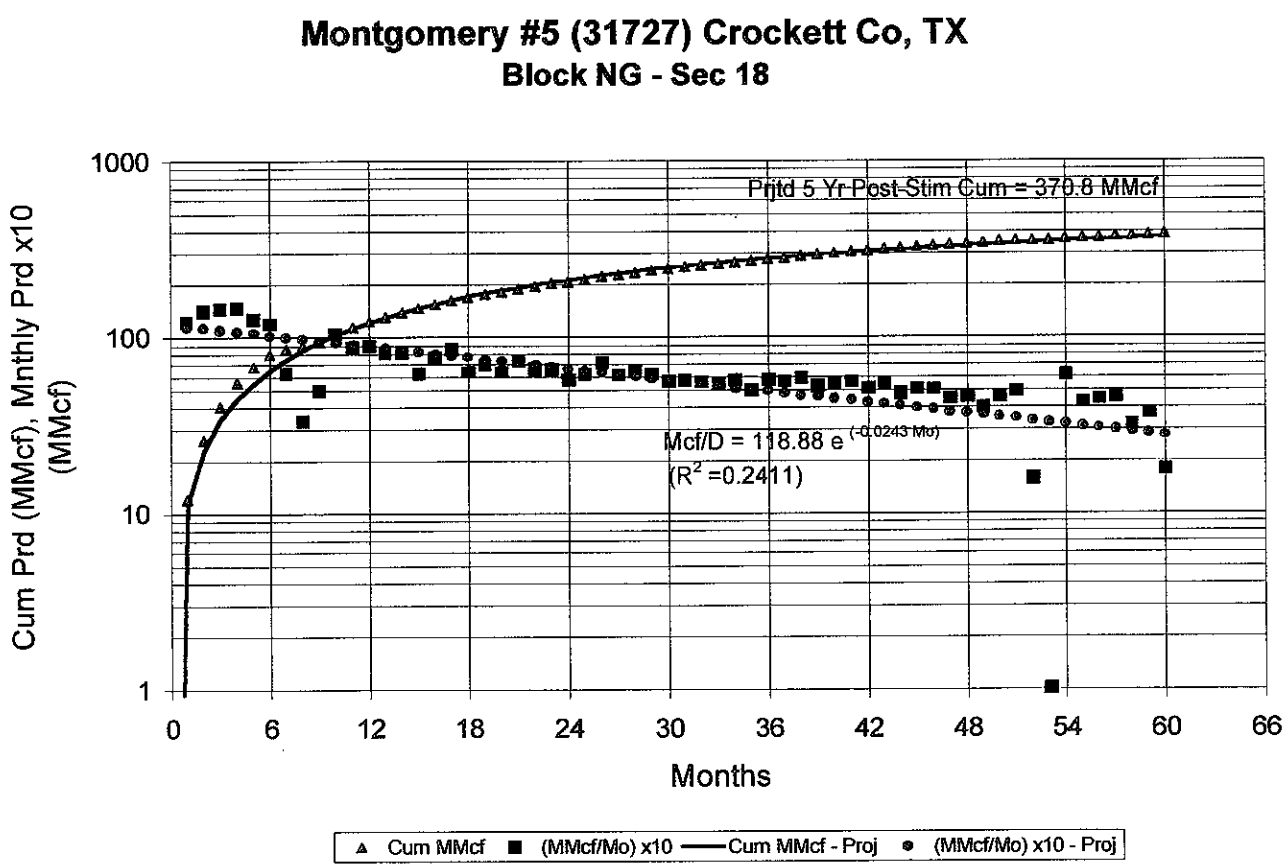
d. Control Well # 4 – Montgomery 07-16 (31725) – Projected 5 Yr Prod 662.0 MMcf



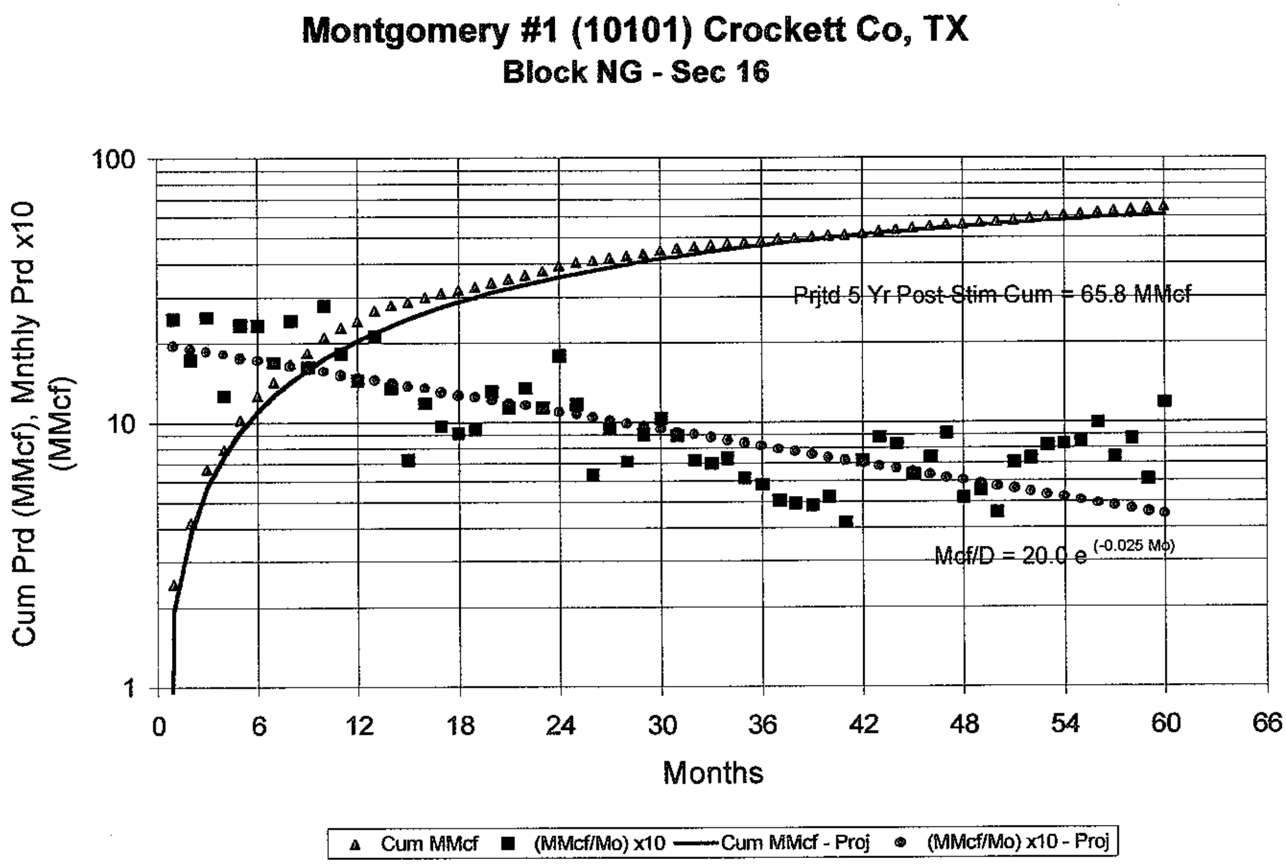
e. Control Well # 5 – Montgomery 04-15 (31021) – Projected 5 Yr Prod 510.9 MMcf



f. Control Well # 6 – Montgomery 05-18 (31727) – Projected 5 Yr Prod 370.8 MMcf

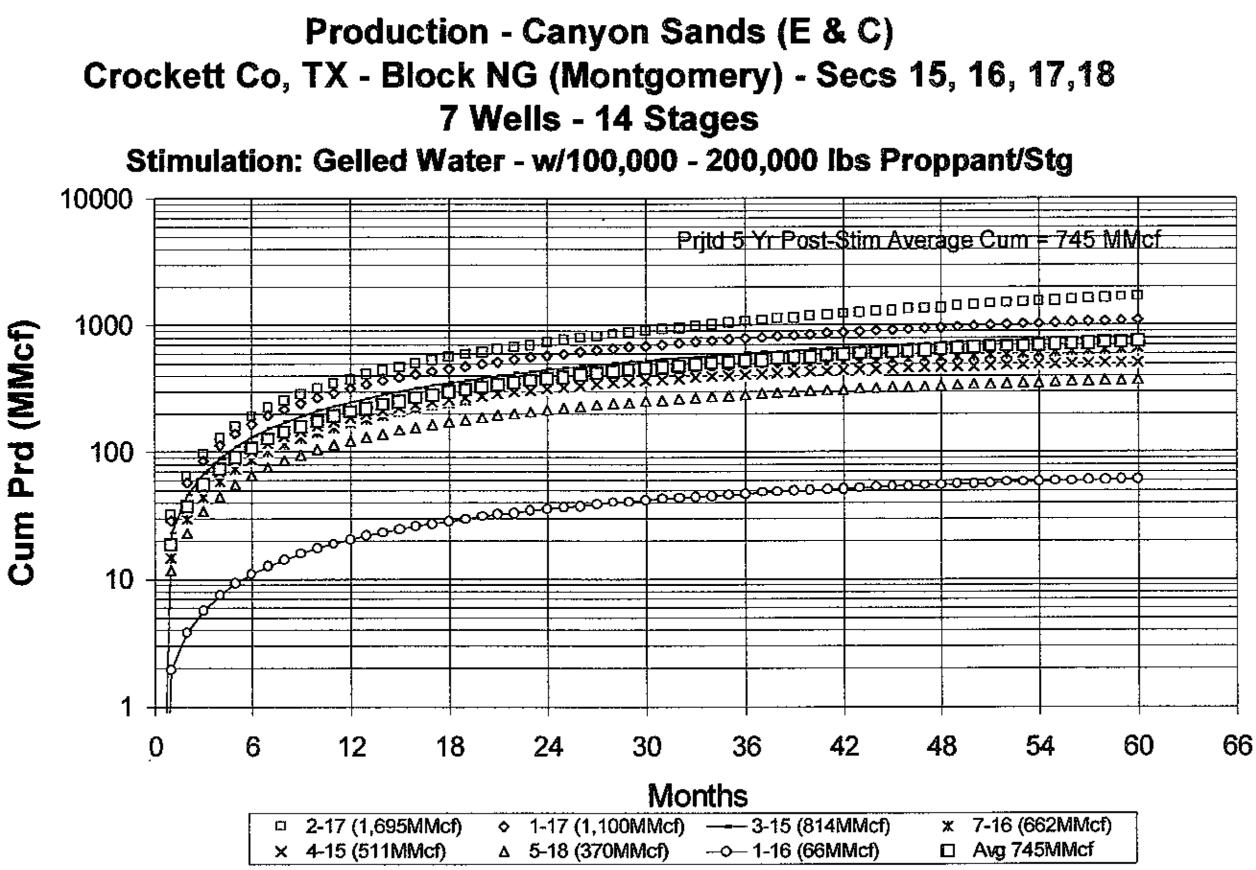


g. Control Well # 7 – Montgomery 01-16 (10101) – Projected 5 Yr Prod 65.8 MMcf



h. Summary – Control Wells

The five year cumulative production volumes from the seven Control Wells ranged from 65.8 to 1,695.2 MMcf and averaged 745 MMcf.



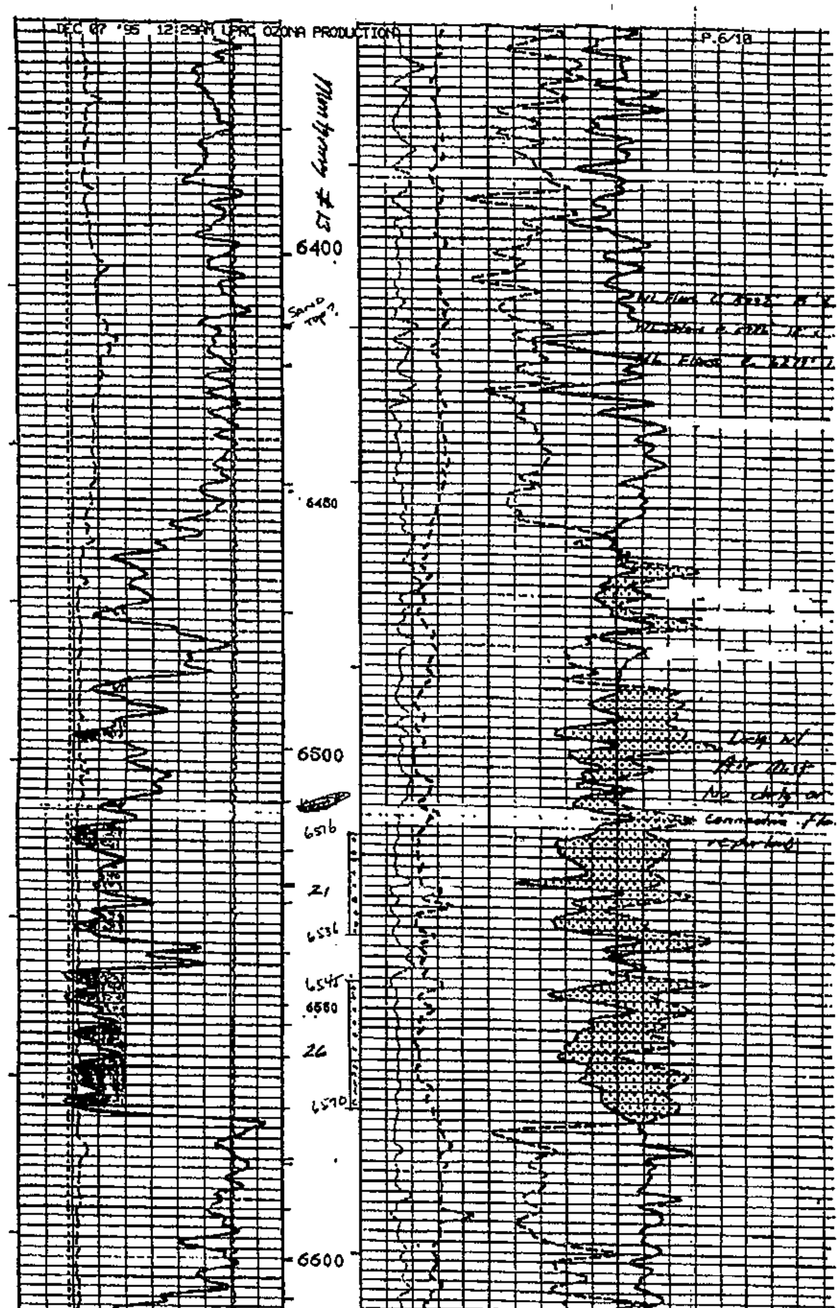
2. Candidate Well Selection - Three Wells

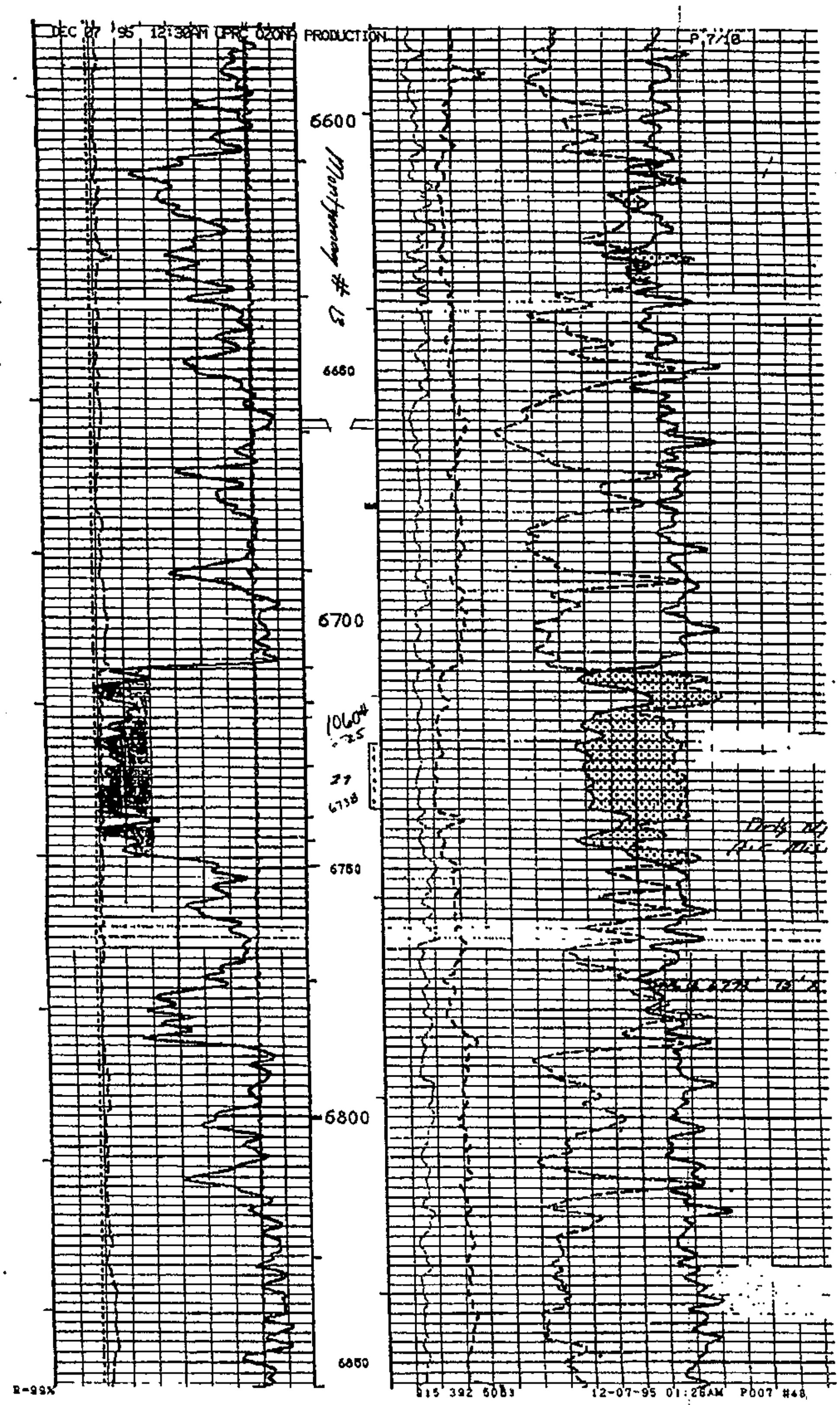
The Candidate Wells in Block NG are the: Montgomery #13-18, 12-18, and 14-18. They were each stimulated with two stages, as is the general practice, to complete the two main pay intervals, the lower (E) and middle (C) zones. The anticipated production was 150-200 Mcfd. The reservoir pressures had been observed to vary between 1000 and 2000 psi.

The Candidate Wells were infill wells which were drilled on 40 acre spacing and the initial plan was to stimulate them with conventional stimulations with an anticipated performance of approximately 70% that of the 80 acre wells drilled previously.

a. Candidate Well #1 – Montgomery 13-18 (36988)

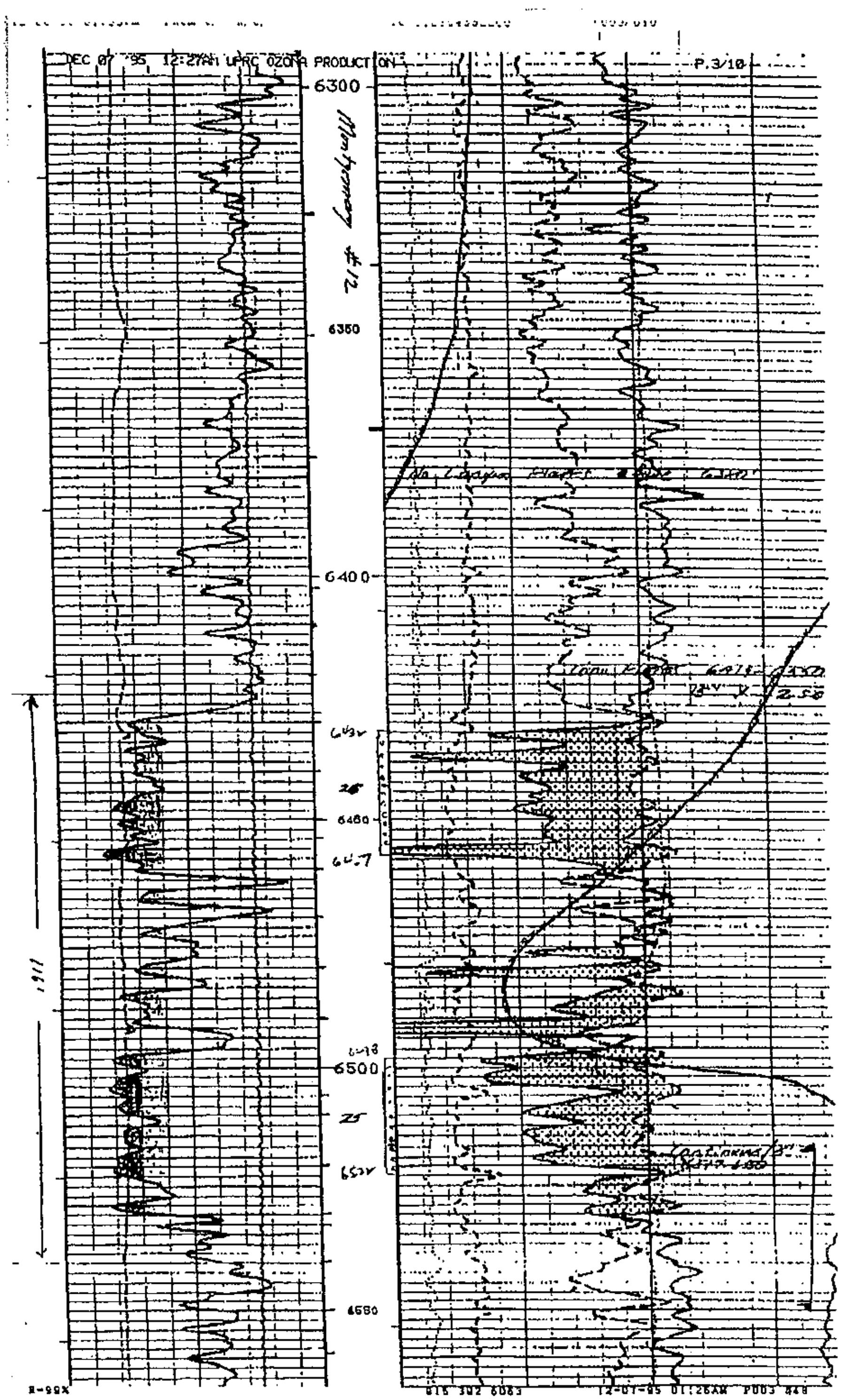
The electric log indicating the perforated intervals follows below.

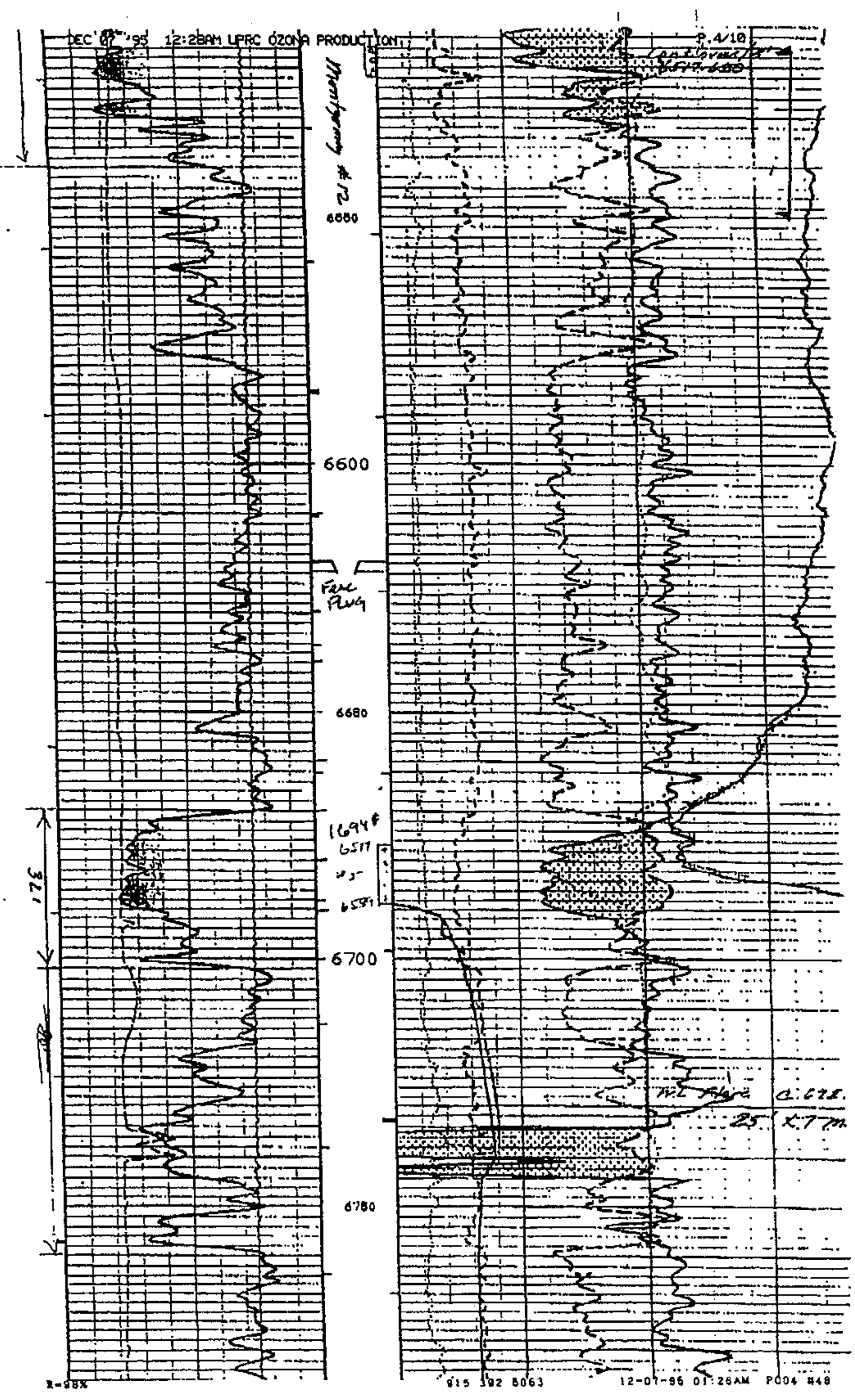

DEC 07 '95 12:29AM UPRC OZONA PRODUCTION
P.6/10
6400
6450
6500
6516
21
6536
6545
6550
26
6570
6600
915 392 6063
12-07-95 01:26AM P006 #48


DEC 07 '95 12:30AM UPRC OZONA PRODUCTION
P.7/10
6600
Montgomery # 13
6650
6700
1060#
6725
27
6738
6750
6800
6850
815 392 5083
12-07-95 01:28AM P007 #48

b. Candidate Well #2 – Montgomery 12-18 (36989)

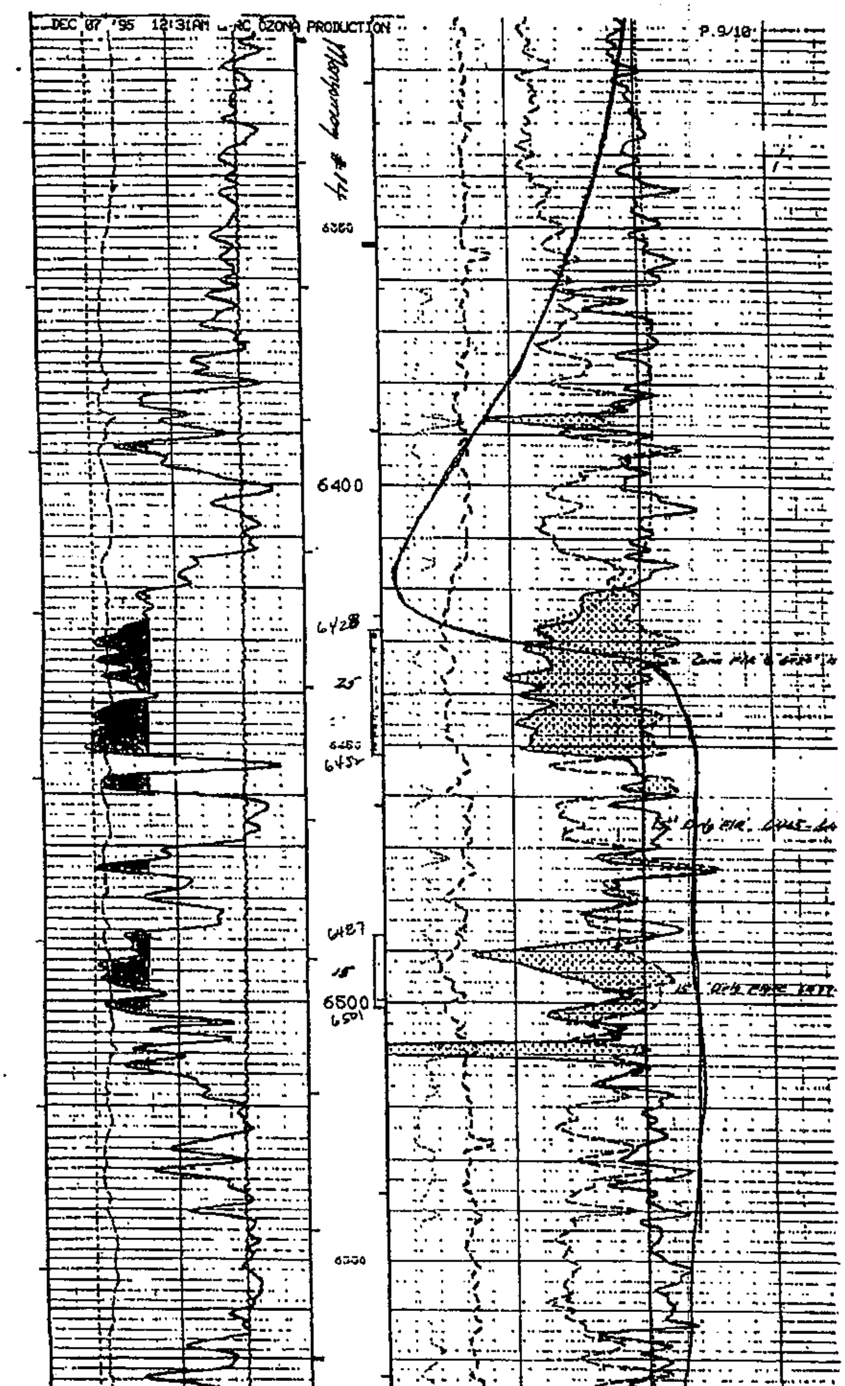
The electric log indicating the perforated intervals follows below.

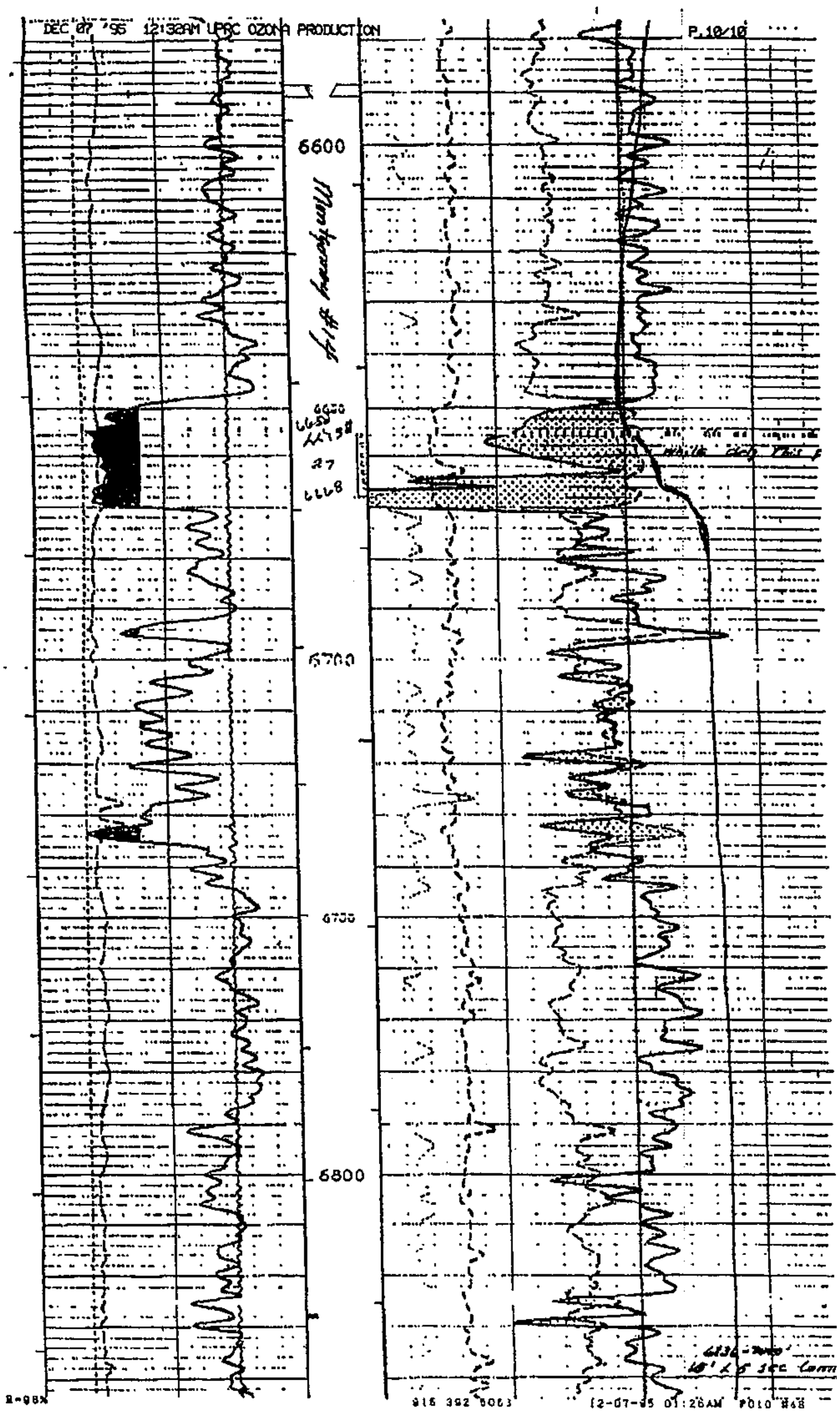



DEC 07 '95 12:28AM UPRC OZONA PRODUCTION
P.4/10
Montgomery #12
6600
Frac Plug
6680
6700
6780
915 392 8063
12-07-95 01:28AM P004 #48

c. Candidate Well #3 - Montgomery 14-18 (36987)

The electric log indicating the perforated intervals follows below.




DEC 07 '95 12:32AM UPRC OZONA PRODUCTION
P.10/10
6600
6700
6800
815 392 6063
12-07-95 01:26AM P010 #48

3. Field Activities

a. Preparations

The wells were prepared for the CO_2/sand stimulations. Two 70 ton CO_2 storage vessels were delivered and filled prior to the treatments

(1) Wellhead isolation tool

On the morning of the treatments, a wellhead isolation tool was run to comply with the pressure rating of the wellhead valving etc.

b. Stimulations

These three Candidate wells were the first to be treated as each was stimulated with two stages with the per stage design being the same as those presented above.

The sand schedule evolved during these treatments where it became evident that a maximum injection rate – as had been predicted (see above) of approximately 40 barrels per minute would be achievable at maximum attainable wellhead treating pressures (6,000-6,500 psi), and that the maximum acceptance sand concentrations for these rates is less than 3 pounds per gallon (ppg).

Three of the six stages screened out; both stages in the Montgomery #13 because the sand concentrations were too great, and also the first in the Montgomery #12.

Montgomery #13 was the first well treated and the maximum acceptance sand concentrations were unknown at the outset. The first stage was treated and screened out as the 3.0 ppg sand concentration started into the formation – 24,200 pounds of sand were placed in zone. Prior to stimulating the second stage, the treating equipment was moved to the Montgomery #12 where the first stage was treated and screened out with 10,400 pounds in zone. The reason for the screen out is believed to be because of reduced injection rates.

The per stage placed proppant volumes ranged from 8,100 to 24,200 pounds. If the lowest volume, 8,100 pounds is removed, the five stage range was 10,400 to 24,200 and averaged 17,600 pounds or approximately twelve percent of that placed in conventional treatments.

A summary of the perforation, stimulation specifics (volumes, rates, pressures) for all three of the Candidate wells is presented and the individual job summary logs and rate-pressure-sand concentration plots for each well are also included as noted below.

PETROLEUM CONSULTING SERVICES
P.O. BOX 35833
CANTON, OH 44735
(216) 499-3823

STIMULATION SUMMARY - FIRST STAGE

DATE: 12/29/95 PAGE 1 OF 4

WELL:	MNTGMRY12	MNTGMRY13	MNTGMRY14
TARGET:	L CANYON	L CANYON	L CANYON
SEC/BLK:	18/NG	18/NG	18/NG
SURVEY:	GC & SF RR	GC & SF RR	GC & SF RR
F?L/F?L:	2720N/1850W	1030S/1870W	478N/2078W
CO/ST:	CROCKETT/TX	CROCKETT/TX	CROCKETT/TX
PMT #(42-105)	36989	36988	36987
OPERATOR:	UPRC	UPRC	UPRC
ELEV GL:	2452	2470	2431
TOT DPTH:	7043	6998	7043
COMPLTED:			
STIMULATED:	12/12/95	12/12/95	12/13/95
PERFS:	25	27	27
TOP:	6577	6725	6655
BOT:	6589	6738	6668
	----	----	----
INTERVAL:	12	13	13
ACID(GAL):	0	0	0
CO2(BBLS):	630	588	635
(TONS):	104	105	98
TOTAL:	150	187	146
PAD(BBLS):	190	155	185
SL(BBLS):	430	313	322
FLUSH(BBLS):	10	120	128
	----	----	----
PMP(BBLS):	630	588	635
SAND(SXS):	250	265	115
IN WELL:	146	23	34
	---	---	---
NET(SXS):	104	242	81
MESH:	20/40	20/40	20/40
N2 (MCF):	102	150	69
RATE(BPM)			
AVG:	40.0	47.0	39.6
MAX:	44.0	50.0	40.6
PRESS(PSI)			
AVG:	5900	5200	5590
MAX:	6500	6200	6678
SND CONC(PPG)			
AVG:	1.4	2.0	0.9
MAX:	2.0	3.0	2.0
HORSEPOWER			
AVG:	5784	6000	5706
MAX:	7000	7600	6453

12/29/95 PAGE 2 OF 4

WELL:	MNTGMRY12	MNTGMRY13	MNTGMRY14
BRK DWN(PSI):			
PRE ISIP(PSI)	5609	6012	5142
RATE(BPM);	46.6	29.1	40.7
ISIP(PSI):	2137	1971	2358
GRAD(PSI/FT):	0.32	0.29	0.35
F(PSI/100FT):	53	60	42
10 MIN(PSI):			2373
AVG SC X SL=	250	265	115
PRESS AT PERFS			
@MAX P(PSI)	9268	8876	9282
@AVG P(PSI)	8557	7861	7876
AVG(PSI):	8913	8369	8579
LIQ(PSI/FT):	0.41	0.40	0.37
SG:	0.95	0.92	0.85
CO2 YLD(BBL/T	5.8	5.3	6.4
PRESS:			
OPN FLO:			
TIL:			
MCFD			
AVG:			
RECENT:			
FROM:			
	SCREENOUT w/104 SXS IN ZONE AVG SC IN ZONE=0.73	SCREENOUT w/241 SXS IN ZONE AVG SC IN ZONE=1.83	SD @39BBLS CSG SVR LK RPR LK RSME TRTMNT
PUMPING($)	13000	13000	26000
N2	1624	3549	1659
SAND	3183	2345	1782
MISC	810	8127	476
	18617	27021	29917
CO2	9750	12155	9490
CO2-PORTABLES	200	200	200
BLENDER	6000	6000	6000
LISC FEE	5000	5000	5000
TUBE TRLR	5500	5500	5500
	26450	28855	26190
MOB,PDIEM:	2984	4583	2984
TRCKNG			
MISC	545	583	545
TOT	48596	61042	59636
$/SK	201	587	246

PETROLEUM CONSULTING SERVICES
P.O. BOX 35833
CANTON, OH 44735
(216) 499-3823

STIMULATION SUMMARY - SECOND STAGE

DATE: 12/29/95 PAGE 3 OF 4

WELL:	MNTGMRY12	MNTGMRY13	MNTGMRY14
TARGET:	L CANYON	L CANYON	L CANYON
SEC/BLK:	18/NG	18/NG	18/NG
SURVEY:	GC & SF RR	GC & SF RR	GC & SF RR
F?L/F?L:	2720N/1850W	1030S/1870W	478N/2078W
CO/ST:	CROCKETT/TX	CROCKETT/TX	CROCKETT/TX
PMT #(42-105)	36989	36988	36987
OPERATOR:	UPRC	UPRC	UPRC
ELEV GL:	2452	2470	2431
TOT DPTH:	7043	6998	7043
COMPLTED:	0		0
STIMULATED:	12/14/95	12/14/95	12/14/95
PERFS:	51	51	40
TOP:	6432	6516	6428
BOT:	6522	6570	6501
INTERVAL:	90	54	73
ACID(GAL):			
CO2(BBLS):	604	583	538
(TONS):	86	92	124
TOTAL:	157	148	190
PAD(BBLS):	195	102	143
SL(BBLS):	307	403	280
FLUSH(BBLS):	102	78	115
PMP(BBLS):	604	583	538
SAND(SXS):	207	261	137
IN WELL:	9	53	8
NET(SXS):	198	208	129
MESH:	20/40	20/40	20/40
N2 (MCF):	102	149	59
RATE(BPM)			
AVG:	43.0	40.0	43.0
MAX:	44.0	44.0	45.5
PRESS(PSI)			
AVG:	5600	5230	5100
MAX:	6100	5796	5432
SND CONC(PPG)			
AVG:	1.6	1.5	1.2
MAX:	2.0	3.0	2.0
HORSEPOWER			
AVG:	5931	5882	6007
MAX:	6147	6470	6357

12/29/95 PAGE 4 OF 4

WELL:	MNTGMRY12	MNTGMRY13	MNTGMRY14	
BRK DWN(PSI):				
PRE ISIP(PSI)	5850	6100	5850	
RATE(BPM);	43.5	42	40	
ISIP(PSI):	2254	2300	2177	
GRAD(PSI/FT):	0.35	0.35	0.34	
F(PSI/100FT):	56	58	57	
5 MIN(PSI):	2056	1100	2000	
AVG SC X SL=	207	261	137	
PRESS AT PERFS				
@MAX P(PSI)	8688	8412	7977	
@AVG P(PSI)	8122	7832	8122	
AVG(PSI):	8405	8122	8050	
LIQ(PSI/FT):	0.39	0.40	0.43	
SG:	0.91	0.92	0.99	
CO2 YLD(BBL/T	6.8	6.0	4.2	
PRESS:				
OPN FLO:				
TIL:		SCREENOUT		
MCFD		W/208 SXS		
AVG:		IN ZONE		
RECENT:		AVG SC IN		
FROM:		ZONE=1.37		
PUMPING($)	8667	8667	8667	
N2	3224	3549	1659	
SAND	2712	4188	1808	
MISC	684	4072	3410	
	15287	20476	15544	
CO2	10205	9620	12350	
CO2-PORTABLES	200	200	200	
BLENDER	0	0	0	
LISC FEE	5000	5000	5000	
TUBE TRLR	2500	2500	2500	
	17905	17320	20050	
MOB,PDIEM:				
TRCKNG				
MISC	284	5073		
TOT	33476	42869	35594	
$/SK	162	164	260	
STAGE 1	48596	61042	59636	
STAGE 2	33476	42869	35594	
TOT	82072	103911	95230	281213

(1) Candidate Well #1 – Montgomery 13-18 (36988)

(a) Stage #1

This was the first well treated in the six well group, and 24,200 pounds of sand were placed in zone, in the first stage. The maximum acceptance sand concentrations were unknown and screened out as the 3.0 ppg sand concentration started into the formation.

The well was perforated with 27 holes over a 13 foot interval from 6,725 to 6,738 feet.

The pressurized blender was transported to the well site on the day of the treatment, December 12, 1995 and filled with 20/40 Brady sand. The treatment was then executed, 26,500 lbs of proppant were pumped at an average rate and pressure of 47.0 barrels per minute and 5,200 psi respectively. The maximum sand concentration was 3.0 lbs per gal, and averaged 2.0, the maximum rates and pressures were 50.0 Bpm and 7,600 psi respectively.

The treatment screened out with 24,200 pounds of proppant in zone for an average in zone proppant concentration of 1.83 ppg.

The instantaneous shut in pressure was 1,971 psi which results in a gradient of 0.29 psi/ft.

(b) Stage #2

Prior to stimulating the second stage, the treating equipment was moved to the Montgomery #12 where the first stage was treated at a reduced injection rate because of mechanical problems and screened out with 10,400 pounds of proppant in zone.

An Alpha Oil Tools Big Bore frac plug was set at 6,580 feet and the second stage was perforated with 51 perforations over a 54 foot interval from 6,516 to 6,570.

The pressurized blender was transported to the well site on the day of the treatment, December 14, 1995 and filled with 20/40 Brady sand. The treatment was then executed, 26,100 lbs of proppant were pumped at an average rate and pressure of 40.0 barrels per minute and 5,230 psi respectively.

The treatment screened out with 20,800 pounds of proppant in zone for an average in zone proppant concentration of 1.37 ppg.

The maximum sand concentration was 3.0 lbs per gal, and averaged 1.5, the maximum rates and pressures were 44.0 Bpm and 5,796 psi respectively. The instantaneous shut in pressure was 2,300 psi which results in a gradient of 0.35 psi/ft. The stimulation pressure-rate history plot is below. The in zone proppant volume was estimated 20,800 pounds.

Montgomery #13

Disregard Procedures dated prior to: 12/11/95

Location	Sec.	Blk	Survey
1030' FSL & 1870' FWL	18	NG	GC & SF RR CO

Elevation:	GL - 2470	KB - 2482

Service:	Company:	Service Date:
Pump Trucks	Halliburton	12/11/95
Wireline	HLS	12/11/95
Nitrogen	Halliburton	12/11/95
CO2	FLOCO2	12/11/95
Tree Saver	Guardian Well Services	12/11/95
Frac Equip.	Universal Services	12/11/95

Size/Wt/Grade/Thrd	Set @	PBTD	Mkr Jt	Mkr Jt	Mkr Jt	TOC
4-1/2" 11.6 N-80 8rd	7034	6998	5856			5500

Existing Lower Canyon Perforations: 6725-6738 (27 holes)

Canyon Completion

(1) MIRU Guardian Well Services. Install casing saver on top of 4-1/2" frac valve. MIRU Halliburton pump trucks and Universal pressurized blender. Frac Lower Canyon with 112 tons CO2 carrying Ottawa sand as follows:

40 BPM Max Pressure-6500 psig

Stage	Gals	Beg ppg	End ppg	Stage Sand		Percent	Pmp Time
CO2 Pad	6000					27%	3.6
Hold	4000	0.5	0.5	2000		18%	2.4
Hold	4000	1	1	4000		18%	2.4
Hold	8300	2	2	16600		37%	4.9
Flush	4200						2.5
26500 gal frac + flush				22600 lbs 20/4 Ottawa			15.8
22300 gals gel			42 Gross Height			538 lbs/ft	
		Flare Quality	NA			531 gals/ft	

Design Rate - To be pumped at as high a rate as possible and push a 6000 psig treating pressure.

(2) Remove casing saver. RU WLU. Install 5000# lubricator. RIH & set 4-1/2" Alpha Oil Tools Big Bore Frac Plug at 6580'. Perforate the Upper Canyon using a 3-1/8" HSC phased 120 degrees as follows:

	Top	Btm	SPF	Holes
Perfs	6516	6536	1	21
Perfs	6545	6570	1	26
	Total Holes:		47	

Perforations per BPB GR/Neutron/Density/Temp. dated 9-24-95.

(3) RD WLU. With 4-1/2" valve closed, place 3-1/2" frac ball on top of gate. Install casing saver on top of 4-1/2" valve. Open valve and allow ball to fall. Scope casing saver mandrel thru valve and into casing.

(4) Frac Upper Canyon with 112 tons CO2 carrying Ottawa sand as follows:

40 BPM Max Pressure-6500 psig

Stage	Gals	Beg ppg	End ppg	Stage Sand		Percent	Pmp Time
CO2 Pad	6000					27%	3.6
Hold	4000	1	1	4000		18%	2.4
Hold	4000	2	2	8000		18%	2.4
Hold	8300	3	3	24900		37%	4.9
Flush	4100						2.4
26400 gal frac + flush				36900 lbs 20/4 Ottawa			15.7
22300 gals gel			114 Gross Height			324 lbs/ft	
		Flare Quality	NA			196 gals/ft	

Design Rate - To be pumped at as high a rate as possible and push a 6000 psig treating pressure.

(5) RD Halliburton and Universal. Commence flowback of well on a 12/64" adjustable choke. Flow back at an estimated rate of 1500 to 2000 mcfpd adjusting choke size as necessary. When frac ball reaches surface, close 4-1/2" master valve. ND upper tree, remove ball. NU tree and continue flowback of well to pit until well cleans up.

(6) Install surface facilities and commence gas sales.

cc: McCollum, Sewell, McDougal, Strickler, Consultants, Well file - Ozona & Ft Worth
c:\complet\montgom\13-p02.wk4

HALLIBURTON ENERGY SERVICES

ACQUIRE Version 2.1

CUSTOMER AND JOB INFORMATION

Customer	U.P.O.G	Date	14-Dec-1995
Contractor		County	CROCKETT
Lease	MONTGOMERY	Town	
Location	OZONA	Section	
Formation	UPPER CANYON	Range	
Job Type	CO2	Permit No	
Country	U.S.A.	Well No	13
State	TEXAS	Field Name	

Customer Representative KELLY JAMERSON   Halliburton Operator DALE PUTNAM   Ticket No. 836024.1

STAGE DESCRIPTIONS

PRIME & TEST
PAD
.5 PPG 20/40
1 PPG 20/40
2 PPG 20/40
3 PPG 20/40
FLUSH

WELL CONFIGURATION INFORMATION

Packer Type   Depth 0 ft
Bottom Hole Temp. 91.0 Deg F

PIPE CONFIGURATION

Wellbore Segment Number	Measured Depth (ft)	TVD (ft)	Casing ID (inch)	Casing OD (inch)	Tubing ID (inch)	Tubing OD (inch)
1	6570	6570	3.950	4.500	0.000	0.000

PERFORATIONS

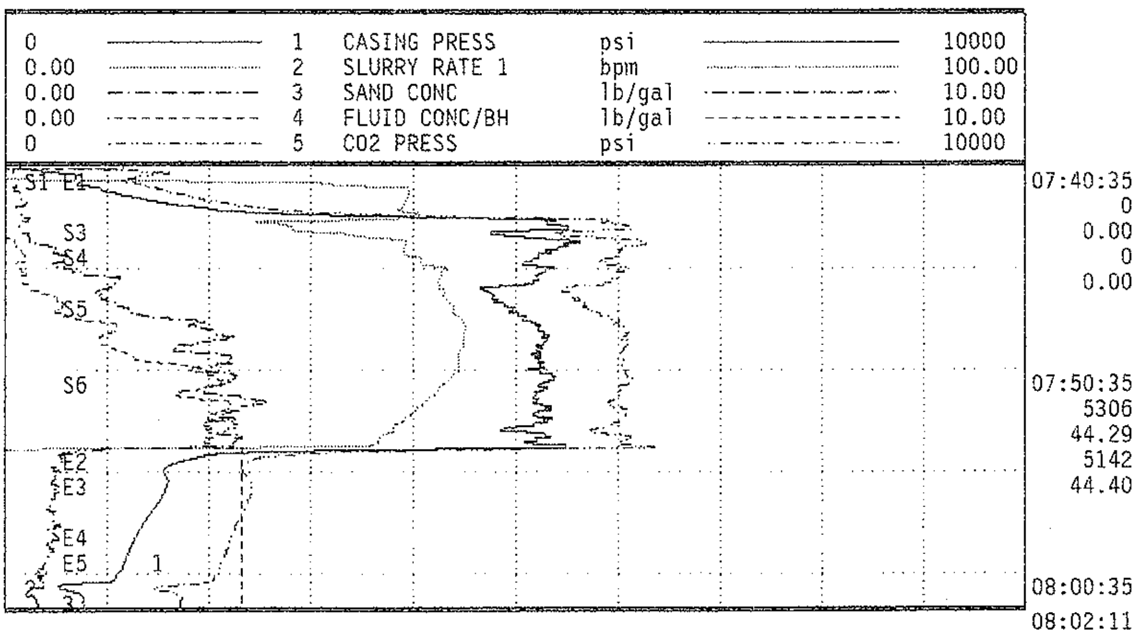
Perforation Interval	Top (ft)	Bottom (ft)	Shots per (ft)
1	6516	6570	0

REMARKS ABOUT JOB

FRACTURE UPPER CANYON

####################
PLAYBACK STRIP CHART
####################

1. Casing Press (psi)
2. Slurry Rate 1 (bpm)
3. Casing Press (psi) Avg for Stg
4. Slurry Rate (bpm) Avg for Stg



Customer:	U.P.O.G	Date:	14-Dec-1995
Well Desc:	MONTGOMERY 13	Ticket #:	836024.1
Formation:	UPPER CANYON	Job Type:	CO2

JOB SUMMARY

JOB START TIME: 07:40:35
JOB END TIME: 08:02:11
JOB DURATION: 00:21:36

STAGES AND EVENTS:

Chart	Time	Slurry Rate (bpm)	Slurry Stage Volume (gal)	Casing Press. (psi)	Remark
Event #1	07:40:35	0.00	0	0	Start Job
Stage #1	07:40:39	0.00	0	331	OPEN WELL HEAD
Stage #2	07:40:51	0.00	4074	692	START PAD
Stage #3	07:43:56	34.59	1025	4989	START .5 PPG
Stage #4	07:44:34	38.97	4156	5321	START 1 PPG
Stage #5	07:46:56	42.94	8472	4718	START 2 PPG
Stage #6	07:51:30	42.39	4626	5263	START 3 PP
Event #2	07:54:44	0.00	0	1920	WELL SCREENED OUT
Event #3	07:55:48	0.00	0	1586	LEFT 115 SKS IN CSG
Event #4	07:59:07	0.00	0	1241	AVG RATE 40 BBL/MIN
Event #5	07:59:50	0.00	0	1180	MAX PSI 6900 PSI AVG PSI 600 0 PSI MIN PSI 5400 PSI
Event #6	08:02:11	0.00	0	263	End Job

Customer:	U.P.O.G	Date:	14-Dec-1995
Well Desc:	MONTGOMERY 13	Ticket #:	836024.1
Formation:	UPPER CANYON	Job Type:	CO2

STAGE SUMMARY

Stage Times

Stage	Start Time	End Time	Elapsed Time
1	07:40:39	07:40:51	00:00:12
2	07:40:51	07:43:56	00:03:05
3	07:43:56	07:44:34	00:00:38
4	07:44:34	07:46:56	00:02:22
5	07:46:56	07:51:30	00:04:34
6	07:51:30	08:02:11	00:10:41
Total	07:40:39	08:02:11	00:21:32

AVERAGES OR VOLUMES PER STAGE -- Planned Volume vs. Actual Volume

Stage	Planned Sl Volume (gal)	Slurry Volume (gal)
1	1000	0
2	4200	4074
3	1718	1025
4	4391	4156
5	9166	8472
6	5343	4626
Tot/Avg	25818	22353

AVERAGES OR VOLUMES PER STAGE -- Strip Chart Variables

Stage	Casing Pressure (psi)	Prop Conc Slurry* (lb/gal)	Prop Conc Bottom* (lb/gal)	CO2 Pressure (psi)
1	437	0.06	0.00	1439
2	2566	0.15	0.00	3157
3	5423	0.34	0.10	6095
4	5090	0.78	0.20	5840
5	5173	1.83	1.21	5978
6	2371	2.18	2.04	3236
Tot/Avg	3364	1.33	1.14	4160

*Average based on volume.

Customer:	U.P.O.G	Date:	14-Dec-1995
Well Desc:	MONTGOMERY 13	Ticket #:	836024.1
Formation:	UPPER CANYON	Job Type:	CO2

STAGE SUMMARY

MAXIMUM VALUE PER STAGE -- Strip Chart Variables

Stage	Casing Pressure (psi)	Prop Conc Slurry* (lb/gal)	Prop Conc Bottom* (lb/gal)	CO2 Pressure (psi)
1	576	0.09	0.00	1670
2	5713	0.26	0.00	6214
3	5617	0.50	0.14	6309
4	5386	1.13	0.50	6169
5	5455	2.30	2.21	6175
6	5796	2.59	2.31	6911
Max Job	5796	2.59	2.31	6911

(2) Candidate Well #2 – Montgomery 12-18 (36989)

(a) Stage #1

The first stage treatment in the Montgomery #12 was compromised by significant CO_2 leaks around the piston rod packings. The leakage was estimated to be at least five (5) barrels per minute. The resultant injection rate after the leaks would be 35 barrels per minute and is believed to be the explanation for the screen out.

The well was perforated with 25 holes over a 12 foot interval from 6,577 to 6,589 feet.

The pressurized blender was transported to the well site on the day of the treatment, December 12, 1995 and filled with 20/40 Brady sand. The treatment was then executed, 25,000 lbs of proppant were pumped at an average rate and pressure of 40.0 barrels per minute and 5,900 psi respectively. The maximum sand concentration was 2.0 lbs per gal, and averaged 1.4, the maximum rates and pressures were 44.0 Bpm and 6,500 psi respectively.

The treatment screened out with 10,400 pounds of proppant in zone for an average in zone proppant concentration of 0.73 ppg.

The instantaneous shut in pressure was 2,137 psi which results in a gradient of 0.32 psi/ft

(b) Stage #2

The well was perforated with 51 holes over a 90 foot interval from 6,432 to 6,522 feet.

The pressurized blender was transported to the well site on the day of the treatment, December 14, 1995 and filled with 20/40 Brady sand. The treatment was then executed, 20,700 lbs of proppant were pumped at an average rate and pressure of 43.0 barrels per minute and 5,600 psi respectively. The maximum sand concentration was 2.0 lbs per gal, and averaged 1.6, the maximum rates and pressures were 44.0 Bpm and 6,100 psi respectively. The instantaneous shut in pressure was 2,254 psi which results in a gradient of 0.35 psi/ft. The stimulation pressure-rate history plot is included. The in zone proppant volume was estimated 19,800 pounds.

HALLIBURTON ENERGY SERVICES

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CUSTOMER AND JOB INFORMATION

Customer	U.P.O.G	Date	14-Dec-1995
Contractor		County	CROCKETT
Lease	MONTGOMERY	Town	
Location	OZONA	Section	
Formation	UPPER CANYON	Range	
Job Type	CO2	Permit No	
Country	U.S.A.	Well No	12
State	TEXAS	Field Name	

Customer Representative KELLY JAMERSON   Halliburton Operator DALE PUTNAM   Ticket No. 838876.1

STAGE DESCRIPTIONS

PRIME & TEST
PAD
.5 PPG 20/40
1 PPG 20/40
2 PPG 20/40
FLUSH

WELL CONFIGURATION INFORMATION

Packer Type   Depth 0 ft
Bottom Hole Temp. 91.0 Deg F

PIPE CONFIGURATION

Wellbore Segment Number	Measured Depth (ft)	TVD (ft)	Casing ID (inch)	Casing OD (inch)	Tubing ID (inch)	Tubing OD (inch)
1	6522	6522	3.950	4.500	0.000	0.000

PERFORATIONS

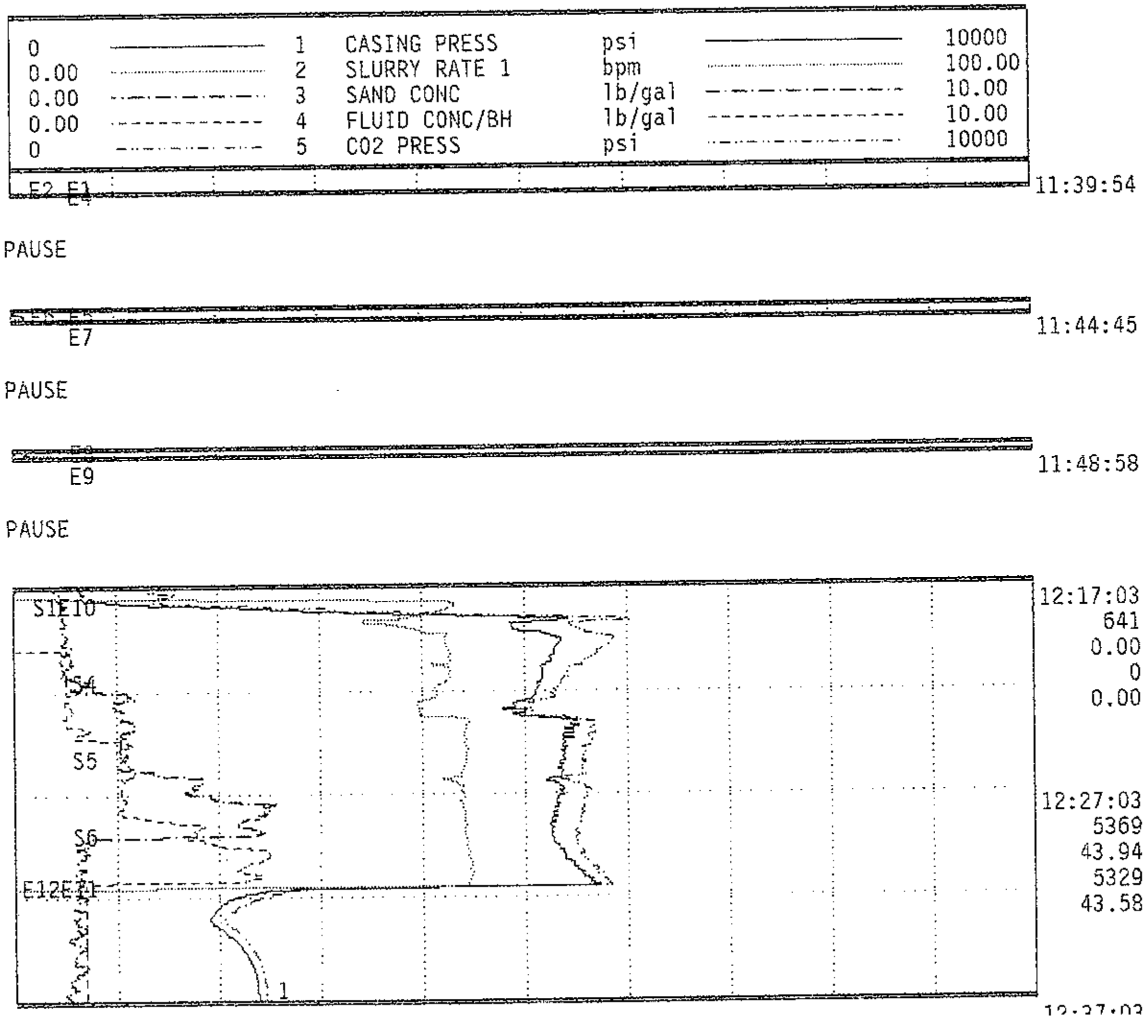
Perforation Interval	Top (ft)	Bottom (ft)	Shots per (ft)
1	6432	6522	0

REMARKS ABOUT JOB

FRACTURE UPPER CANYON

####################
PLAYBACK STRIP CHART
####################

1. Casing Press (psi)
2. Slurry Rate 1 (bpm)
3. Casing Press (psi) Avg for Stg
4. Slurry Rate (bpm) Avg for Stg



Customer:	U.P.O.G	Date:	14-Dec-1995
Well Desc:	MONTGOMERY 12	Ticket #:	838876.1
Formation:	UPPER CANYON	Job Type:	CO2

JOB SUMMARY

JOB START TIME: 11:38:55
JOB END TIME: 12:37:03
JOB DURATION: 00:58:08

STAGES AND EVENTS:

Chart	Time	Slurry Rate (bpm)	Slurry Stage Volume (gal)	Casing Press. (psi)	Remark
Event #1	11:38:55	0.00	0	0	Start Job
Event #2	11:39:01	0.00	0	-9	ON LOC 10;00 AM
Event #3	11:39:39	0.00	0	-9	Start Job
Event #4	11:39:54	0.00	0	-9	Pause
Event #5	11:44:27	0.00	0	103	Resume
Event #6	11:44:31	0.00	0	103	START COOL DOWN
Event #7	11:44:45	0.00	0	106	Pause
Event #8	11:48:48	3.66	0	168	Resume
Event #9	11:48:58	3.76	0	171	Pause
Event #10	12:17:03	0.00	0	641	Resume
Stage #1	12:17:24	11.74	75	669	SKIP
Stage #2	12:17:30	32.10	5524	746	START PAD
Stage #3	12:20:43	40.73	1981	5180	START .5 PPG SAND
Stage #4	12:21:49	41.15	6723	5128	START 1 PPG SAND
Stage #5	12:25:35	44.05	6131	5380	START 2 PPG SAND
Stage #6	12:28:54	43.91	4836	5280	START FLUSH
Event #11	12:31:38	0.00	0	2488	FLUSH COMPLETE
Event #12	12:31:51	0.00	0	2254	ISIP Casing Press 2254 (psi)
Event #13	12:37:03	0.00	0	2377	End Job

Customer:	U.P.O.G	Date:	14-Dec-1995
Well Desc:	MONTGOMERY 12	Ticket #:	838876.1
Formation:	UPPER CANYON	Job Type:	CO2

STAGE SUMMARY

Stage Times

Stage	Start Time	End Time	Elapsed Time
1	12:17:24	12:17:30	00:00:06
2	12:17:30	12:20:43	00:03:13
3	12:20:43	12:21:49	00:01:06
4	12:21:49	12:25:35	00:03:46
5	12:25:35	12:28:54	00:03:19
6	12:28:54	12:37:03	00:08:09
Total	12:17:24	12:37:03	00:19:39

AVERAGES OR VOLUMES PER STAGE -- Planned Volume vs. Actual Volume

Stage	Planned Sl Volume (gal)	Slurry Volume (gal)
1	1000	75
2	6000	5524
3	2045	1981
4	7319	6723
5	6547	6131
6	4811	4836
Tot/Avg	27722	25269

AVERAGES OR VOLUMES PER STAGE -- Strip Chart Variables

Stage	Casing Pressure (psi)	Prop Conc Slurry* (lb/gal)	Prop Conc Bottom* (lb/gal)	CO2 Pressure (psi)
1	695	0.45	0.00	1341
2	4491	0.49	0.46	4961
3	5155	0.56	0.48	5398
4	5241	1.05	0.73	5433
5	5303	1.98	1.22	5539
6	3239	0.73	2.06	3382
Tot/Avg	4274	1.05	1.13	4504

*Average based on volume.

Customer: U.P.O.G
Well Desc: MONTGOMERY 12
Formation: UPPER CANYON

Date: 14-Dec-1995
Ticket #: 838876.1
Job Type: CO2

STAGE SUMMARY

MAXIMUM VALUE PER STAGE -- Strip Chart Variables

Stage	Casing Pressure (psi)	Prop Conc Slurry* (lb/gal)	Prop Conc Bottom* (lb/gal)	CO2 Pressure (psi)
1	726	0.46	0.00	1354
2	5480	0.58	0.48	6068
3	5180	0.76	0.51	5532
4	5623	1.22	1.14	5725
5	5397	2.61	1.84	5664
6	5751	2.41	2.50	5885
Max Job	5751	2.61	2.50	6068

(3) Candidate Well #3 -- Montgomery 14-18 (36987)

(a) Stage #1

The well was perforated with 27 holes over a 13 foot interval from 6,655 to 6,668 feet.

The pressurized blender was transported to the well site on the day of the treatment, December 13, 1995 and filled with 20/40 Brady sand. The treatment was then executed, 11,500 lbs of proppant were pumped at an average rate and pressure of 39.6 barrels per minute and 5,590 psi respectively.

The treatment had to be temporarily discontinued after pumping 39 barrels of CO_2 because of a leaking wellhead isolation tool. The pumping was halted and the pressure bled from the well head to replace a leaking element. The pumping was resumed after approximately two hours.

The maximum sand concentration was 2.0 lbs per gal, and averaged 0.9, the maximum rates and pressures were 40.6 Bpm and 6,453 psi respectively. The instantaneous shut in pressure was 2,358 psi which results in a gradient of 0.35 psi/ft. The stimulation pressure-rate history plot is below. The in zone proppant volume was an estimated 8,100 pounds.

HALLIBURTON ENERGY SERVICES

ACQUIRE Version 2.1

CUSTOMER AND JOB INFORMATION

Customer	U.P.O.G	Date	13-Dec-1995
Contractor		County	CROCKETT
Lease	MONTGOMERY	Town	
Location	OZONA	Section	
Formation	LOWER CANYON	Range	
Job Type	CO2	Permit No	
Country	U.S.A.	Well No	14
State	TEXAS	Field Name	

Customer Representative KELLY JAMERSON   Halliburton Operator DALE PUTNAM   Ticket No. 838877

STAGE DESCRIPTIONS

PRIME & TEST
PAD
PAD
1 PPG 20/40
2 PPG 20/40
FLUSH

WELL CONFIGURATION INFORMATION

Packer Type   Depth 0 ft
Bottom Hole Temp. 91.0 Deg F

PIPE CONFIGURATION

Wellbore Segment Number	Measured Depth (ft)	TVD (ft)	Casing ID (inch)	Casing OD (inch)	Tubing ID (inch)	Tubing OD (inch)
1	6668	6668	3.950	4.500	0.000	0.000

PERFORATIONS

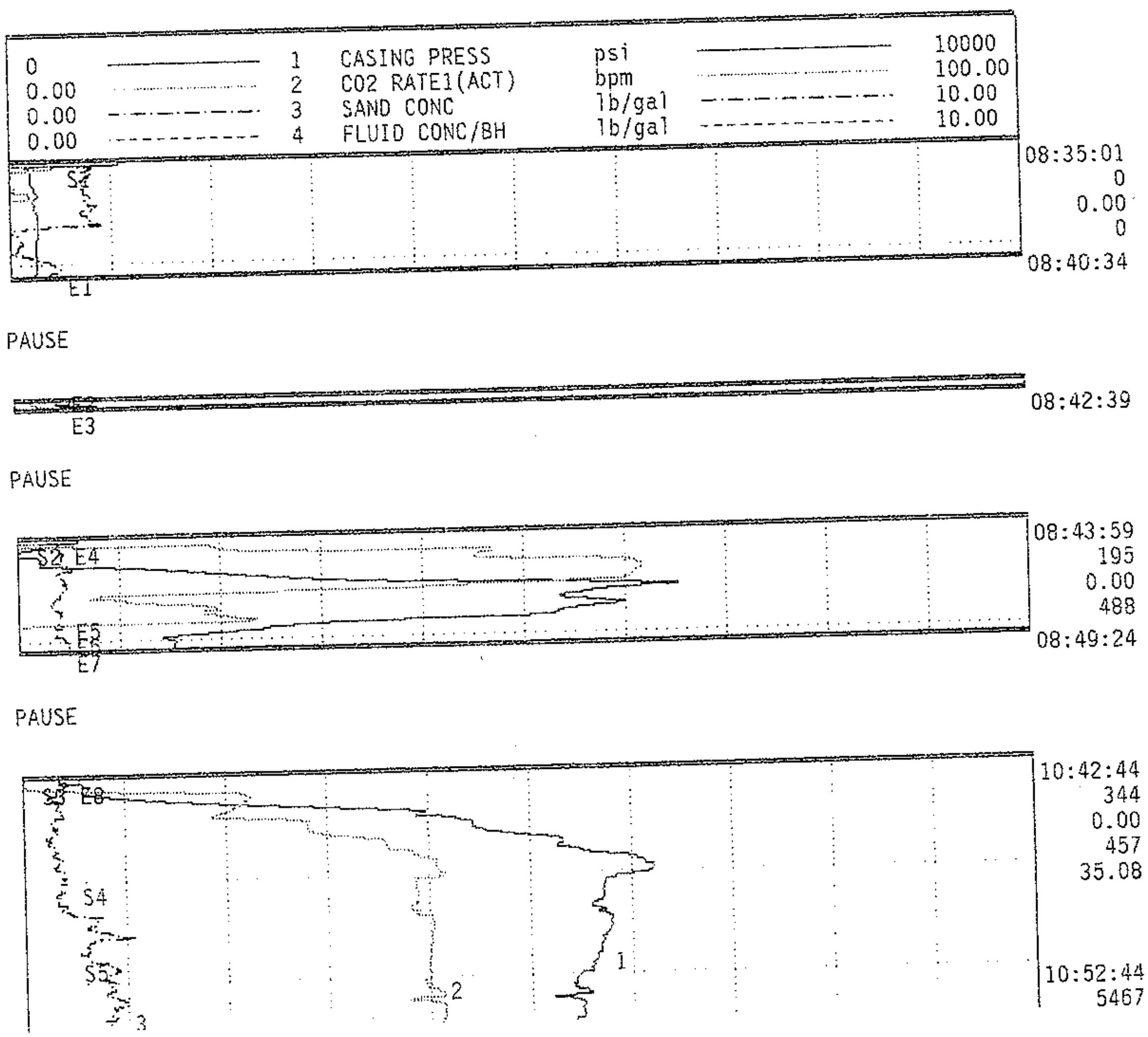
Perforation Interval	Top (ft)	Bottom (ft)	Shots per (ft)
1	6655	6668	0

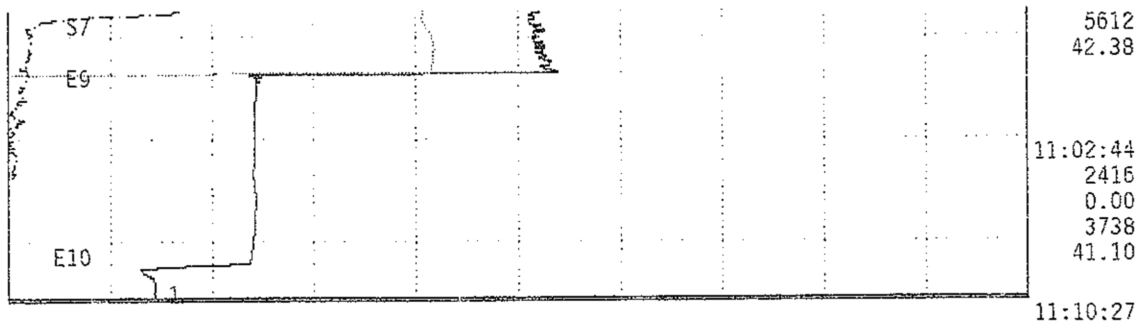
REMARKS ABOUT JOB

PUMP 140 TONS OF CO2 AND 226 SKS 20/40 OTTOWA AT 50 BBL/MIN AT APPROXIMATELY 4000 PSI WITH MAXIMUM PSI OF 6000 PSI.

####################
PLAYBACK STRIP CHART
####################

1. Casing Press (psi)
2. CO2 Rate1(Act) (bpm)
3. Casing Press (psi) Avg for Stg
4. CO2 Rate/Standard (bpm) Avg for Stg





Customer:	U.P.O.G	Date:	13-Dec-1995
Well Desc:	MONTGOMERY 14	Ticket #:	838877
Formation:	LOWER CANYON	Job Type:	CO2

JOB SUMMARY

JOB START TIME: 08:35:01
JOB END TIME: 11:10:27
JOB DURATION: 02:35:26

STAGES AND EVENTS:

Chart	Time	CO2Act Rate (bpm)	CO2Act Stage Volume (gal)	Casing Press. (psi)	Remark
Stage #1	08:35:01	0.00	94	0	Start Job
Event #1	08:40:34	0.00	0	238	Pause
Event #2	08:42:25	5.70	0	1436	Resume
Event #3	08:42:39	2.65	0	1012	Pause
Event #4	08:43:59	0.00	0	195	Resume
Stage #2	08:44:09	0.00	5850	214	start pad
Event #5	08:48:16	0.00	0	2684	TREESAVER LEAKING SHUT DOWN TO REPAIR
Event #6	08:49:18	0.00	0	1534	Resume
Event #7	08:49:24	0.00	0	1538	Pause
Event #8	10:42:44	0.00	0	344	Resume
Stage #3	10:42:48	0.00	6485	560	START PAD
Stage #4	10:48:12	38.66	5477	5734	START .5 PPG SAND
Stage #5	10:51:31	39.94	6753	5685	START 1 PPG 20/40
Stage #6	10:55:29	40.52	1732	5304	START 2 PPG
Stage #7	10:56:31	40.70	5107	5142	START FLUSH
Event #9	10:59:45	0.00	0	2358	ISIP Casing Press 2358 (psi)
Event #10	11:08:41	0.00	0	2373	10 Min Shutin Pres. Casing P ress 2373 (psi)
Event #11	11:10:27	0.00	0	1427	End Job

Customer:	U.P.O.G	Date:	13-Dec-1995
Well Desc:	MONTGOMERY 14	Ticket #:	838877
Formation:	LOWER CANYON	Job Type:	CO2

STAGE SUMMARY

Stage Times

Stage	Start Time	End Time	Elapsed Time
1	08:35:01	08:44:09	00:09:08
2	08:44:09	10:42:48	01:58:39
3	10:42:48	10:48:12	00:05:24
4	10:48:12	10:51:31	00:03:19
5	10:51:31	10:55:29	00:03:58
6	10:55:29	10:56:31	00:01:02
7	10:56:31	11:10:27	00:13:56
Total	08:35:01	11:10:27	02:35:26

AVERAGES OR VOLUMES PER STAGE -- Planned Volume vs. Actual Volume

Stage	Planned Gs Volume (gal)	CO2 (Act) Volume (gal)
1	1000	94
2	8000	5850
3	8000	6485
4	12547	5477
5	2500	6753
6	5082	1732
7	0	5107
Tot/Avg	37129	31498

AVERAGES OR VOLUMES PER STAGE -- Strip Chart Variables

Stage	Casing Pressure (psi)	Prop Conc Slurry* (lb/gal)	Prop Conc Bottom* (lb/gal)
1	482	0.78	0.00
2	457	0.41	0.00
3	4108	0.37	0.00
4	5722	0.34	0.00
5	5498	0.59	0.00
6	5248	0.79	0.00
7	2886	1.65	0.00
Tot/Avg	1076	0.78	0.00

Customer: U.P.O.G
Well Desc: MONTGOMERY 14
Formation: LOWER CANYON

Date: 13-Dec-1995
Ticket #: 838877
Job Type: CO2

STAGE SUMMARY

MAXIMUM VALUE PER STAGE -- Strip Chart Variables

Stage	Casing Pressure (psi)	Prop Conc Slurry* (lb/gal)	Prop Conc Bottom* (lb/gal)
1	1550	0.93	0.00
2	6678	0.53	0.00
3	6255	0.47	0.00
4	5828	1.15	0.00
5	5690	1.01	0.00
6	5362	1.69	0.00
7	5472	1.65	0.00
Max Job	6678	1.69	0.00

(b) Stage #2

The well was perforated with 40 holes over a 73 foot interval from 6,428 to 6,501 feet.

The pressurized blender was transported to the well site on the day of the treatment, December 14, 1995 and filled with 20/40 Brady sand. The treatment was then executed, 13,700 lbs of proppant were pumped at an average rate and pressure of 43.0 barrels per minute and 5,100 psi respectively. The maximum sand concentration was 2.0 lbs per gal, and averaged 1.2, the maximum rates and pressures were 43.0 Bpm and 5,432 psi respectively. The instantaneous shut in pressure was 2,177 psi which results in a gradient of 0.34 psi/ft. The stimulation pressure-rate history plot is below. The in zone proppant volume was estimated 12,900 pounds.

HALLIBURTON ENERGY SERVICES

ACQUIRE Version 2.1

CUSTOMER AND JOB INFORMATION

Customer	U.P.O.G	Date	14-Dec-1995
Contractor		County	CROCKETT
Lease	MONTGOMERY	Town	
Location	OZONA	Section	
Formation	UPPER CANYON	Range	
Job Type	CO2	Permit No	
Country	U.S.A.	Well No	14
State	TEXAS	Field Name	

Customer Representative KELLY JAMERSON   Halliburton Operator DALE PUTNAM   Ticket No. 838877.1

STAGE DESCRIPTIONS

PRIME & TEST
PAD
.5 PPG 20/40
1 PPG 20/40
2 PPG 20/40
FLUSH

WELL CONFIGURATION INFORMATION

Packer Type   Depth 0 ft
Bottom Hole Temp. 91.0 Deg F

PIPE CONFIGURATION

Wellbore Segment Number	Measured Depth (ft)	TVD (ft)	Casing ID (inch)	Casing OD (inch)	Tubing ID (inch)	Tubing OD (inch)
1	6501	6501	3.950	4.500	0.000	0.000

PERFORATIONS

Perforation Interval	Top (ft)	Bottom (ft)	Shots per (ft)
1	6428	6501	0

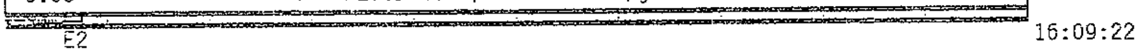
REMARKS ABOUT JOB

FRACTURE UPPER CANYON

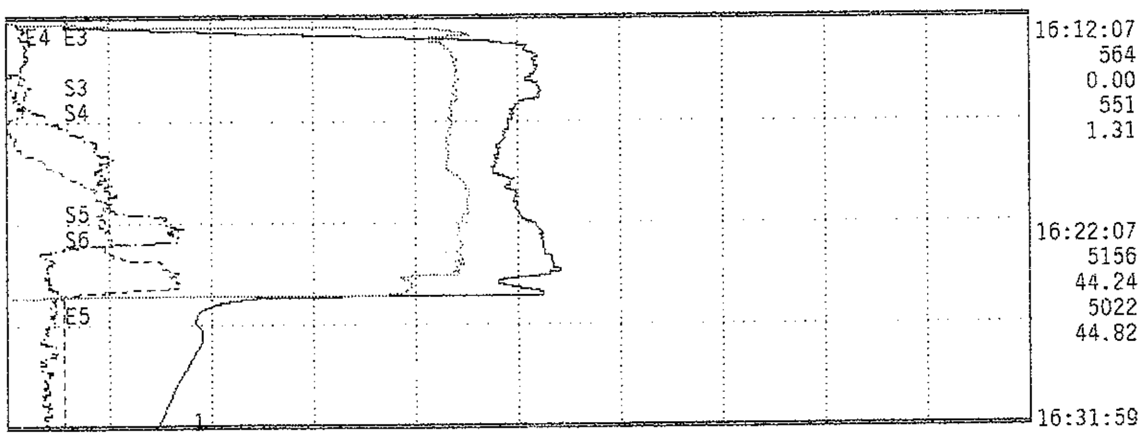
####################
PLAYBACK STRIP CHART
####################

1. Casing Press (psi)
2. Slurry Rate 1 (bpm)
3. Casing Press (psi) Avg for Stg
4. Slurry Rate (bpm) Avg for Stg

0	1	CASING PRESS	psi	10000
0.00	2	SLURRY RATE 1	bpm	100.00
0.00	3	SAND CONC	lb/gal	10.00
0.00	4	FLUID CONC/BH	lb/gal	10.00



PAUSE



Customer:	U.P.O.G	Date:	14-Dec-1995
Well Desc:	MONTGOMERY 14	Ticket #:	838877.1
Formation:	UPPER CANYON	Job Type:	CO2

JOB SUMMARY

JOB START TIME: 16:09:02
JOB END TIME: 16:31:59
JOB DURATION: 00:22:57

STAGES AND EVENTS:

Chart	Time	Slurry Rate (bpm)	Slurry Stage Volume (gal)	Casing Press. (psi)	Remark
Event #1	16:09:02	0.00	0	0	Start Job
Stage #1	16:09:06	4.30	23	1100	PRIME UP
Stage #2	16:09:16	0.18	6092	269	START PAD
Event #2	16:09:22	2.99	0	251	Pause
Event #3	16:12:07	0.00	0	564	Resume
Event #4	16:12:14	5.86	0	603	START PAD
Stage #3	16:15:41	43.55	2257	5198	START .5 PPG
Stage #4	16:16:55	43.30	7656	4917	START 1 PPG
Stage #5	16:21:05	45.10	3428	4972	START 2 PPG
Stage #6	16:22:55	44.20	4811	5214	START FLUSH
Event #5	16:25:54	0.00	0	2177	ISIP Casing Press 2177 (psi)
Event #6	16:31:59	0.00	0	1477	End Job

Customer:	U.P.O.G	Date:	14-Dec-1995
Well Desc:	MONTGOMERY 14	Ticket #:	838877.1
Formation:	UPPER CANYON	Job Type:	CO2

STAGE SUMMARY

Stage Times

Stage	Start Time	End Time	Elapsed Time
1	16:09:06	16:09:16	00:00:10
2	16:09:16	16:15:41	00:06:25
3	16:15:41	16:16:55	00:01:14
4	16:16:55	16:21:05	00:04:10
5	16:21:05	16:22:55	00:01:50
6	16:22:55	16:31:59	00:09:04
Total	16:09:06	16:31:59	00:22:53

AVERAGES OR VOLUMES PER STAGE -- Planned Volume vs. Actual Volume

Stage	Planned Sl Volume (gal)	Slurry Volume (gal)
1	1000	23
2	6000	6092
3	2045	2257
4	7319	7656
5	6547	3428
6	4808	4811
Tot/Avg	27719	24266

AVERAGES OR VOLUMES PER STAGE -- Strip Chart Variables

Stage	Casing Pressure (psi)	Prop Conc Slurry* (lb/gal)	Prop Conc Bottom* (lb/gal)
1	557	0.03	0.00
2	2649	0.14	0.17
3	5008	0.19	0.15
4	4858	0.85	0.40
5	5100	1.42	0.95
6	2801	0.50	1.29
Tot/Avg	3421	0.62	0.66

*Average based on volume.

Customer:	U.P.O.G	Date:	14-Dec-1995
Well Desc:	MONTGOMERY 14	Ticket #:	838877.1
Formation:	UPPER CANYON	Job Type:	CO2

STAGE SUMMARY

MAXIMUM VALUE PER STAGE -- Strip Chart Variables

Stage	Casing Pressure (psi)	Prop Conc Slurry* (lb/gal)	Prop Conc Bottom* (lb/gal)
1	1100	0.04	0.00
2	5224	0.26	0.24
3	5206	0.38	0.18
4	4999	1.10	1.02
5	5260	1.74	1.02
6	5432	1.68	1.69
Max Job	5432	1.74	1.69

(c) Stimulation Summary

The stimulation specifics are summarized:

Summary							
		Sand (sacks)		Max Tr Press	Avg Rate	Sand Conc (lb/gal)	
Well	Stg	Pumped	In-Zone	(psi)	(BPM)	Max	Avg
M#13	1	265	242	6,200	47.0	3.0	2.0
M#13	2	261	208	5,796	40.0	3.0	1.5
M#12	1	250	104	6,500	40.0	2.0	1.4
M#12	2	207	198	6,100	43.0	2.0	1.6
M#14	1	115	81	5,590	39.6	2.0	0.9
M#14	2	137	129	5,600	43.0	2.0	1.2

c. Post Stimulation

(1) Flow Back Procedures

The flow back procedure was initiated immediately following the removal of the stimulation hardware. The flow was restricted with a choke to enable the CO_2 vapor to flow safely. The choke size was increased as the pressure diminished and the CO_2 concentration was monitored. Some sand was produced as was expected because of the intentional under flush.

(2) Cleaning Frac Sand from the Well Bore

Following the stimulations the three Candidate wells were all cleaned by jetting the sand from them with nitrogen gas. The three Candidate wells were, as is generally the case with the CO_2/sand stimulations - because of the designed under flush, found to have sand in them above the perforations. The fill up in Montgomery 12-18 (1st stage) was 1,676 feet due to the screen out as was the 2nd stage in Montgomery 13-18; however, the fill up in the other four stages was less than that typically encountered being from three to 14 feet above the lowermost perforation.

Stage 1				
Well	Perf Intvl	Sand Top	Fill-up	Clean Out Depth
	(ft)	(ft)	(ft) (lbs)	(ft)
Montgomery 13-18	6,725 – 6,738	6,724	274 (2,390)	6,998
Montgomery 12-18	6,577 – 6,589	933	1,676 (14,630)	7,043
Montgomery 14-18	6,655 – 6,668	6,657	386 (3,370)	7,043

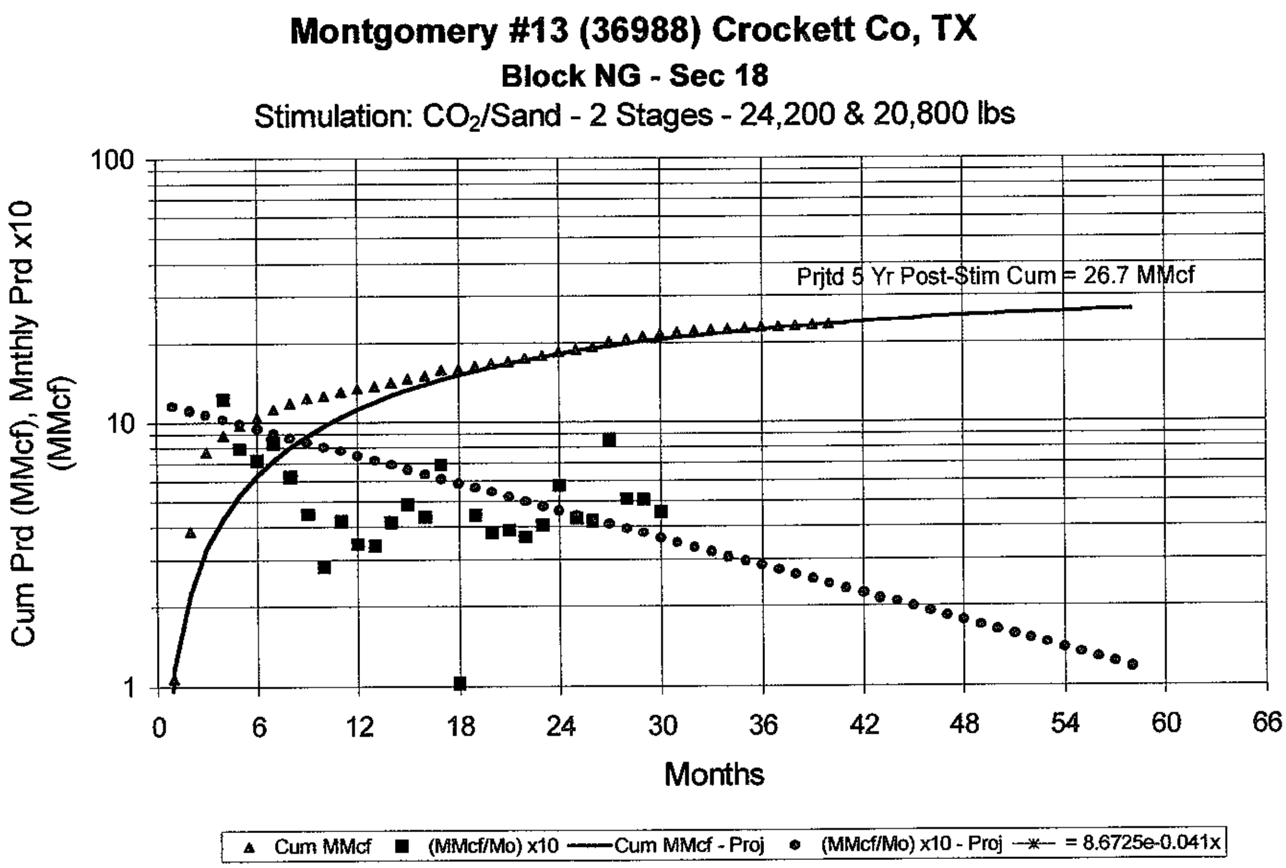
Stage 2				
Well	Perf Intvl	Sand Top	Fill-up	Clean Out Depth
	(ft)	(ft)	(ft) (lbs)	(ft)
Montgomery 13-18	6,516 – 6,570	6,055	605 (5,280)	6,660
Montgomery 12-18	6,432 – 6,522	6,519	101 (880)	6,620
Montgomery 14-18	6,428 – 6,501	6,498	92 (800)	6,590

(3) Tubing Installation

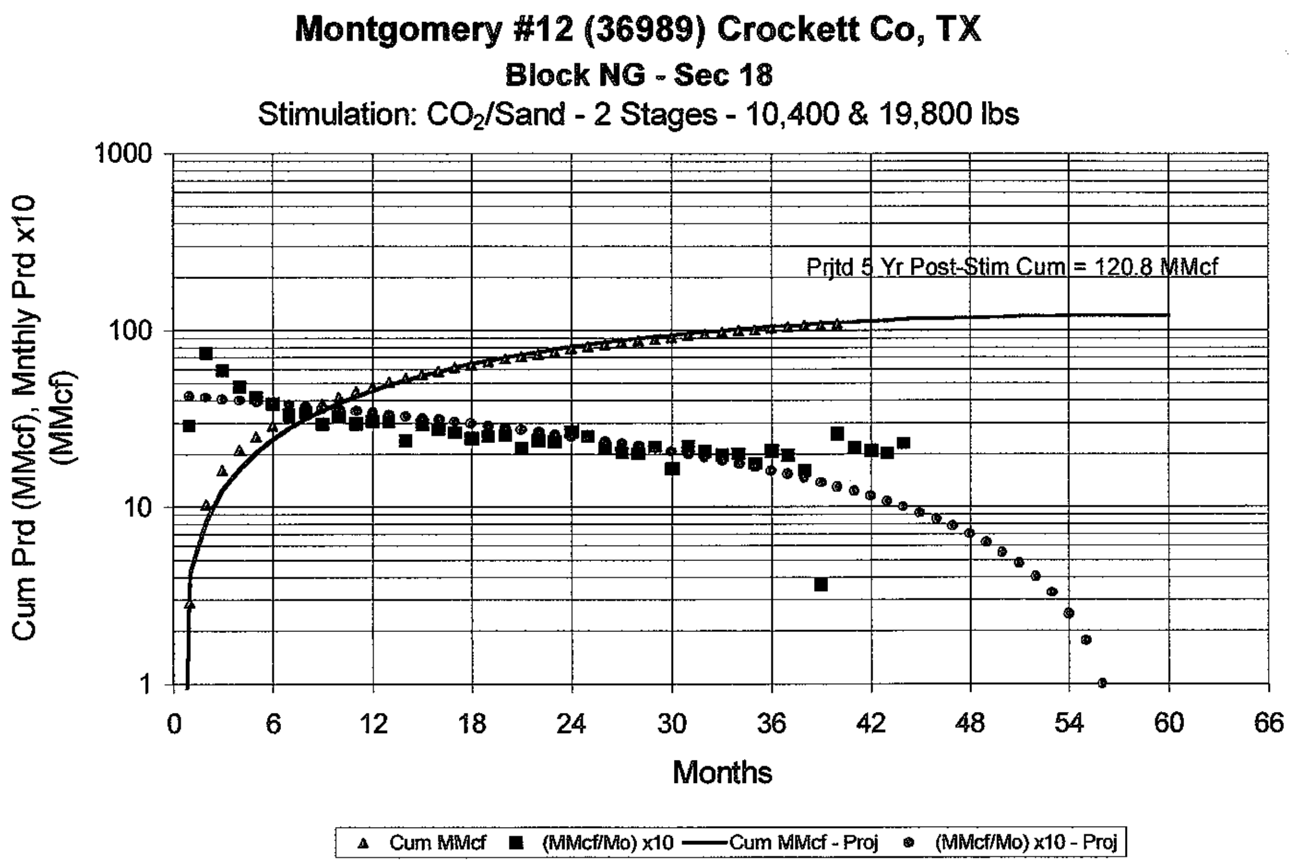
A 1-1/4 inch coiled tubing was installed for liquid removal. The wells were produced through the tubing, some with intermitters, and no plunger lift hardware was present.

4. Results - Production Comparisons

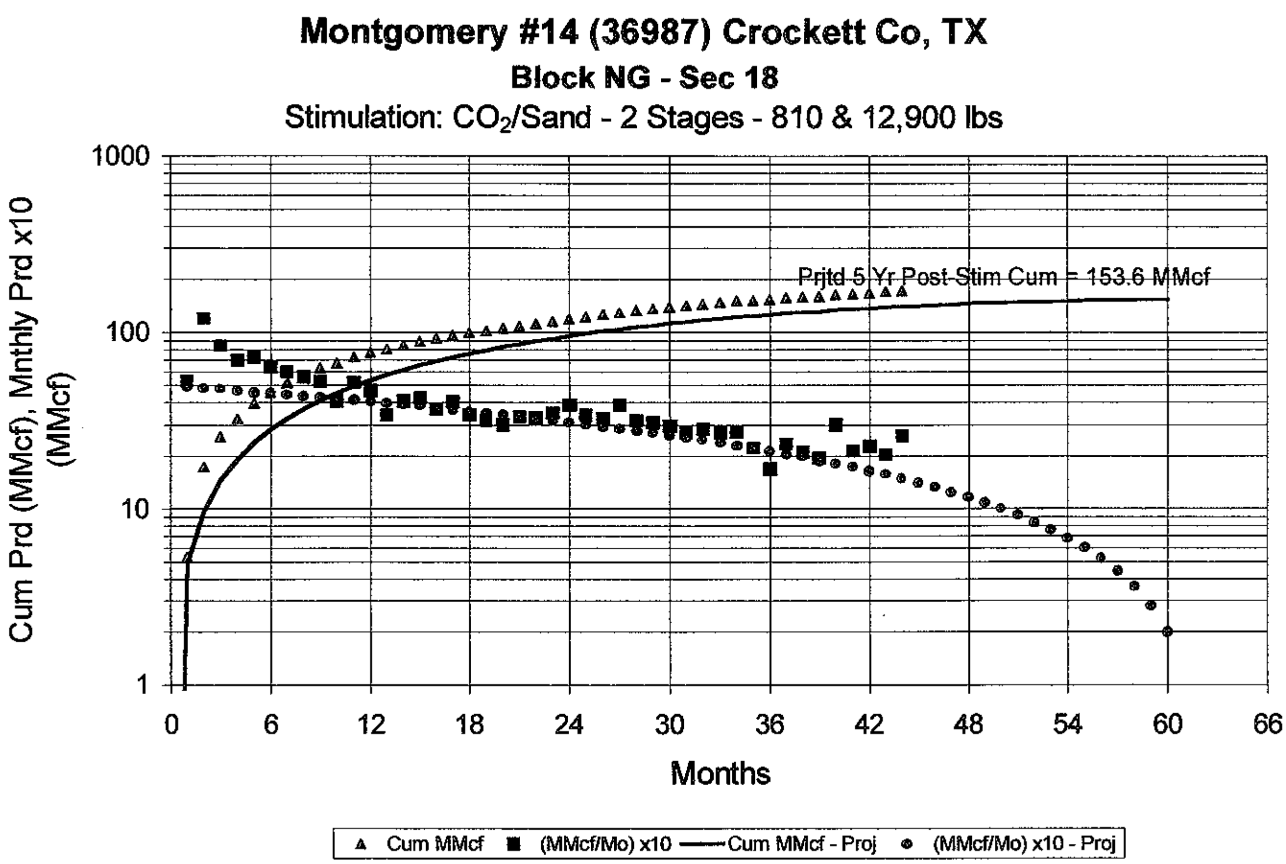
   a. Candidate Well #1 – Montgomery 13-18 (36988)



b. Candidate Well #2 – Montgomery 12-18 (36989)

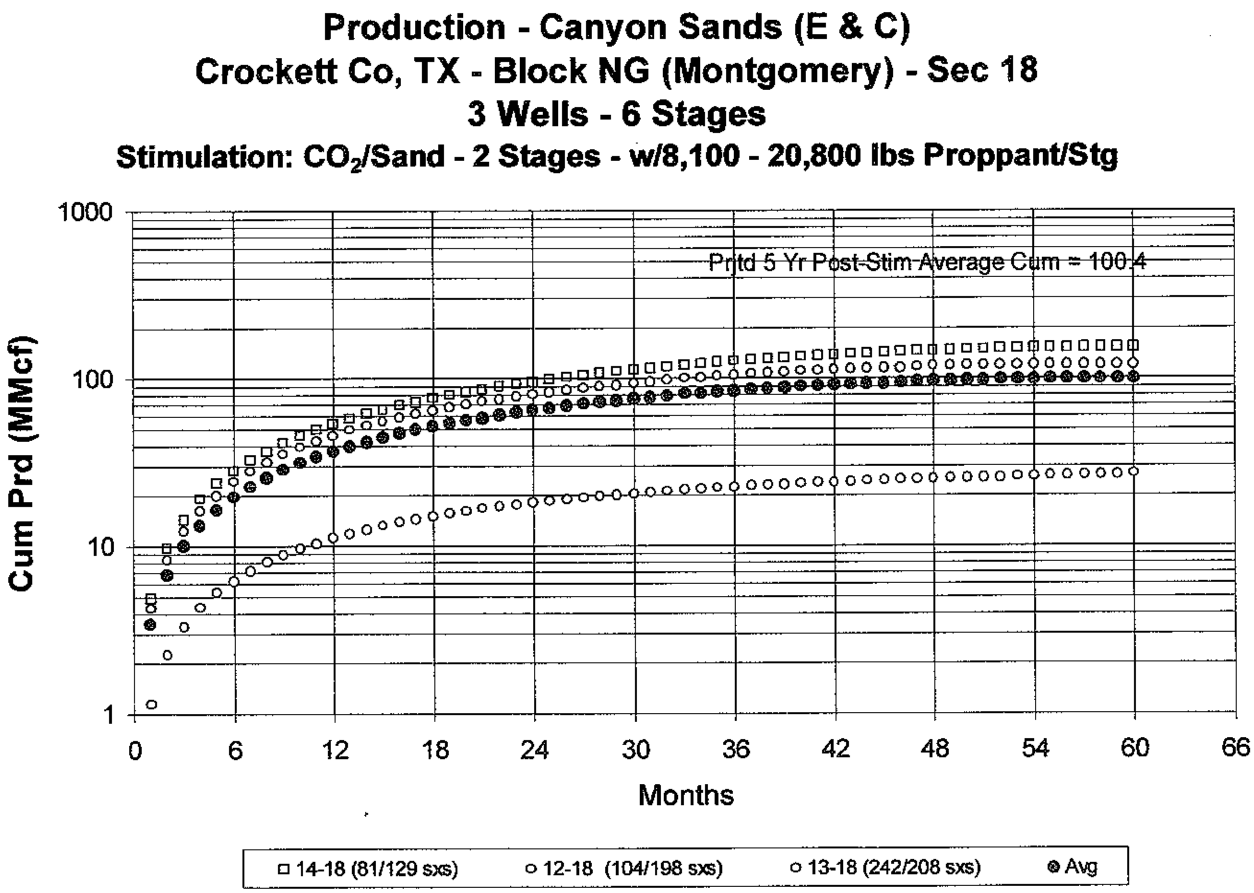


c. Candidate Well #3 -- Montgomery 14-18 (36987)



d. Summary – Candidate Wells

The five year cumulative production from the three Candidate Wells ranged between 26.7 and 153.6 MMcf and averaged 100.4 MMcf.

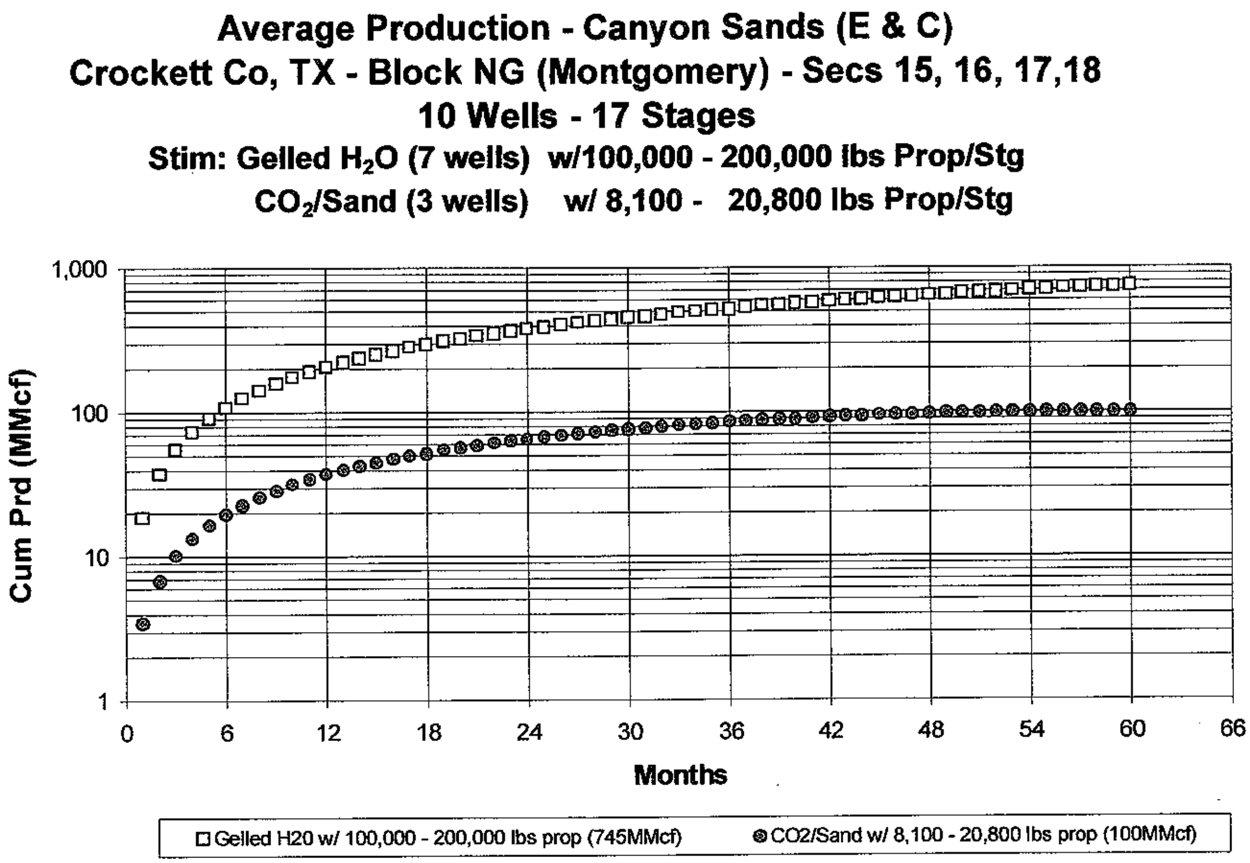


e. Production Comparisons – Summary

The five year cumulative production volumes from the three Candidate Wells ranged from 26.7 to 153.6 MMcf and averaged 100.4 MMcf, or 13 percent that of the ten Control Wells.

Well	Pmt # 42-105- xxxx	5 Yr Prod Projt'd (MMcf)	Stim Type, Sxs, Bbls
Montgomery 02-17	10786	1,695.2	
Montgomery 01-17	10785	1,100.2	
Montgomery 03-15	30742	814.4	
Montgomery 07-16	31725	662.0	
Montgomery 04-15	31021	510.9	
Montgomery 05-18	31727	370.8	
Montgomery 14-18	36987	153.6	CO_2 81, 635 CO_2 129, 538
Montgomery 12-18	36989	120.8	CO_2 104, 630 CO_2 198, 604
Montgomery 01-16	10101	65.8	
Montgomery 13-18	36988	26.7	CO_2 242, 588 CO_2 208, 583

These poor responses from the wells stimulated with the CO_2/sand process are unquestionably related to a number of factors regarding the formation characteristics of permeability and pressure, but to a larger extent to the reduced proppant volumes placed by the liquid-free treatments.



5. Conclusions - Test Area #1

a. The liquid CO_2/sand stimulations were somewhat successfully pumped in the Canyon Sands. Although it had not been conclusively established that they could be successfully pumped they were, but at considerably reduced proppant volumes than the design.

The proppant volumes placed were much less than the design and ranged from 8,100 to 24,200 pounds per stage. If the lowest volume, 8,100 pounds is removed, the five stage range was 10,400 to 24,200 and averaged 17,600 pounds or approximately twelve percent of that placed in conventional treatments.

The actual volumes placed in zone were:

Stage 1			
	Pumped	Removed from well	Net in zone
Well	(K lbs)	(K lbs)	(K lbs)
Montgomery 13-18	26.5	2.3	24.2
Montgomery 12-18	25.0	14.6	10.4
Montgomery 14-18	11.5	3.4	8.1

Stage 2			
	Pumped	Removed from well	Net in zone
Well	(K lbs)	(K lbs)	(K lbs)
Montgomery 13-18	26.1	5.3	20.8
Montgomery 12-18	20.7	0.9	19.8
Montgomery 14-18	13:7	0.8	12.9

b. The production from the three Candidate Wells was considerably less than that from the Control Wells.

The projected five year cumulative production averaged 100.4 MMcf while that from the seven Control wells averaged 745.0 MMcf or 7.4 times that from the wells stimulated with the liquid CO_2/sand process.

c. These poor responses from the wells stimulated with the CO_2/sand process are unquestionably related to a number of factors regarding the formation characteristics of permeability, and pressure, <u>but to a larger extent to the reduced proppant volumes placed by the liquid-free treatments</u>

d. The ability to place the design quantities was obviously limited by

   (1) The reduced pump rate of 40 barrels per minute, which was driven by a maximum tubular strength limitation of 6,500 psi.
   (2) High leak off rates into the formation.

e. The costs for the CO_2/sand stimulations (6 wells - 9 stages) was $407,462 or $45,274 per stage. Cost advantages resulted from a major reduction in pumping costs through the utilization of a locally available service company, Halliburton Energy Services (HES). The original bid was much greater and also required a significant mobilization charge. To a lesser extent, a cost savings for CO_2 of $7,380 was realized by utilizing another supplier.

f. In retrospect the inability of Halliburton to provide the design pump rate primarily because of the significant CO_2 leaks and the utilization of small diameter plungers compromised the ability to place proppant.

g. Significant equipment problems with CO_2 leakage around the piston rods was experienced. There were twelve Halliburton pumpers and the leakage became so severe that they were not visible from the blender operators position. They were shut down and partially remediated.

B. Test Area #2 - Block MM (Hoover-Hatton)

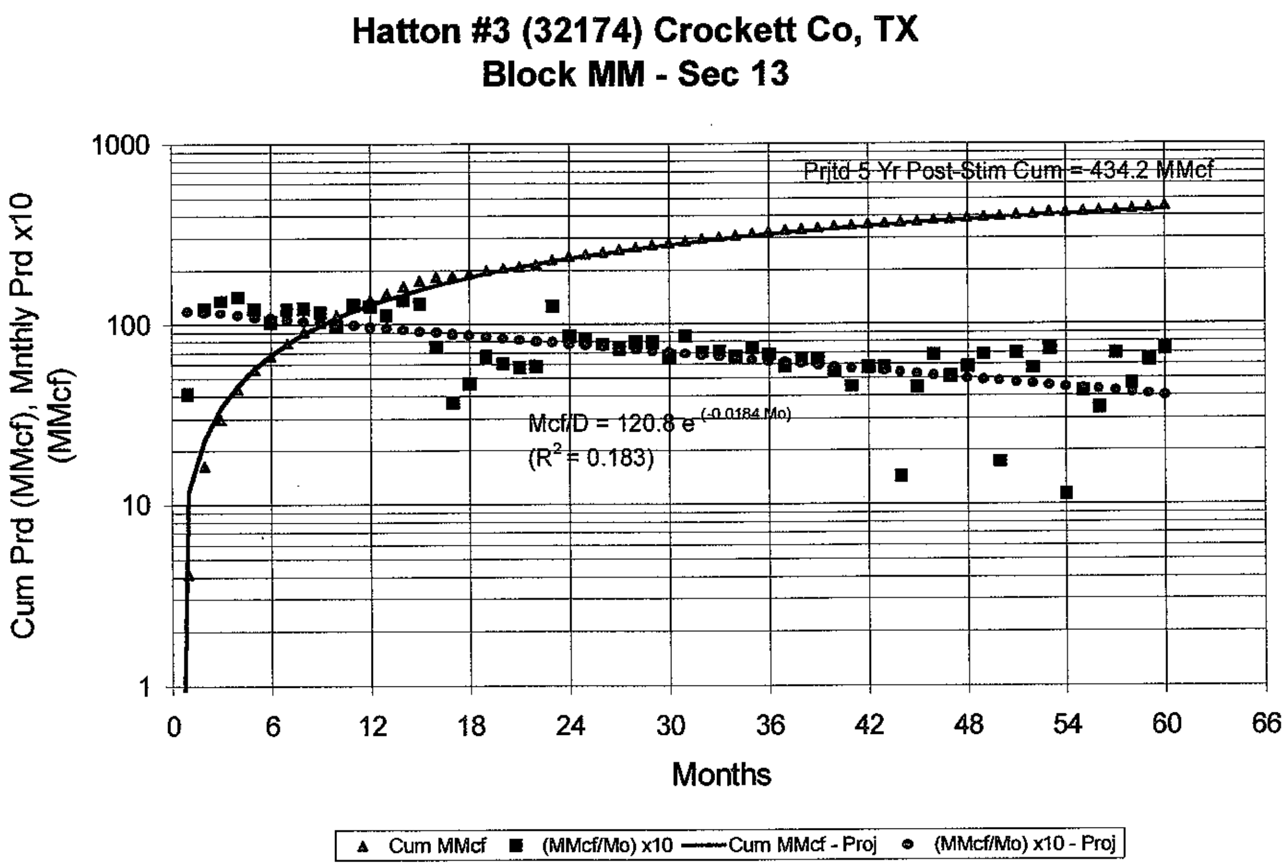
Block MM has an areal extent of four sections. The previous spacing was 80 acres which was, at the time, reduced to 40 subject to a pending request. There were 25 producing wells in Block MM. Four CO_2/Sand stimulation sites were offered. In-house electric logs for sixteen were provided.

1. Control Wells - 10 Wells

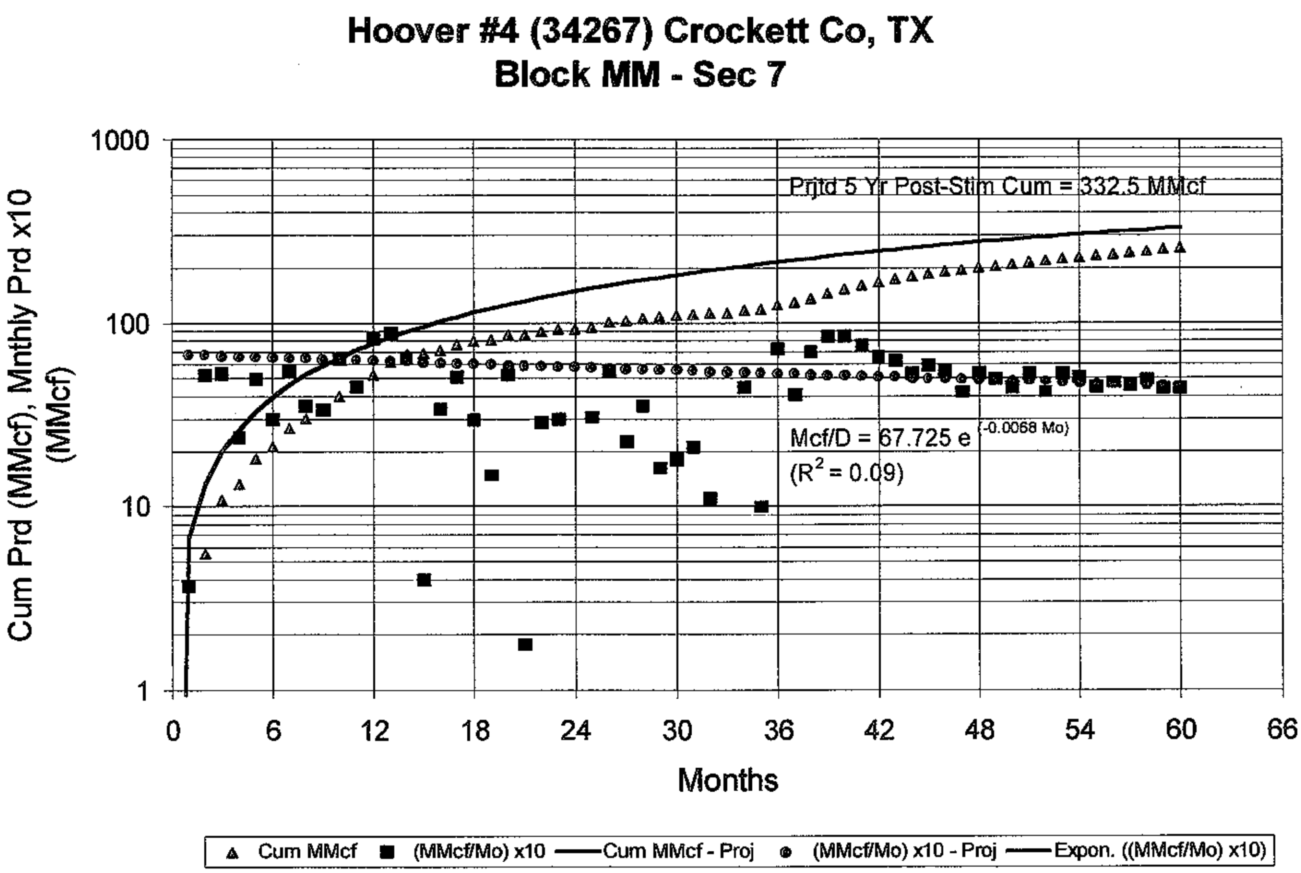
   Production Review and Projections

   The production was plotted and the five year production projection exclusive of flush production and non-productive intervals was generated as described under the preceding METHODOLGY section.

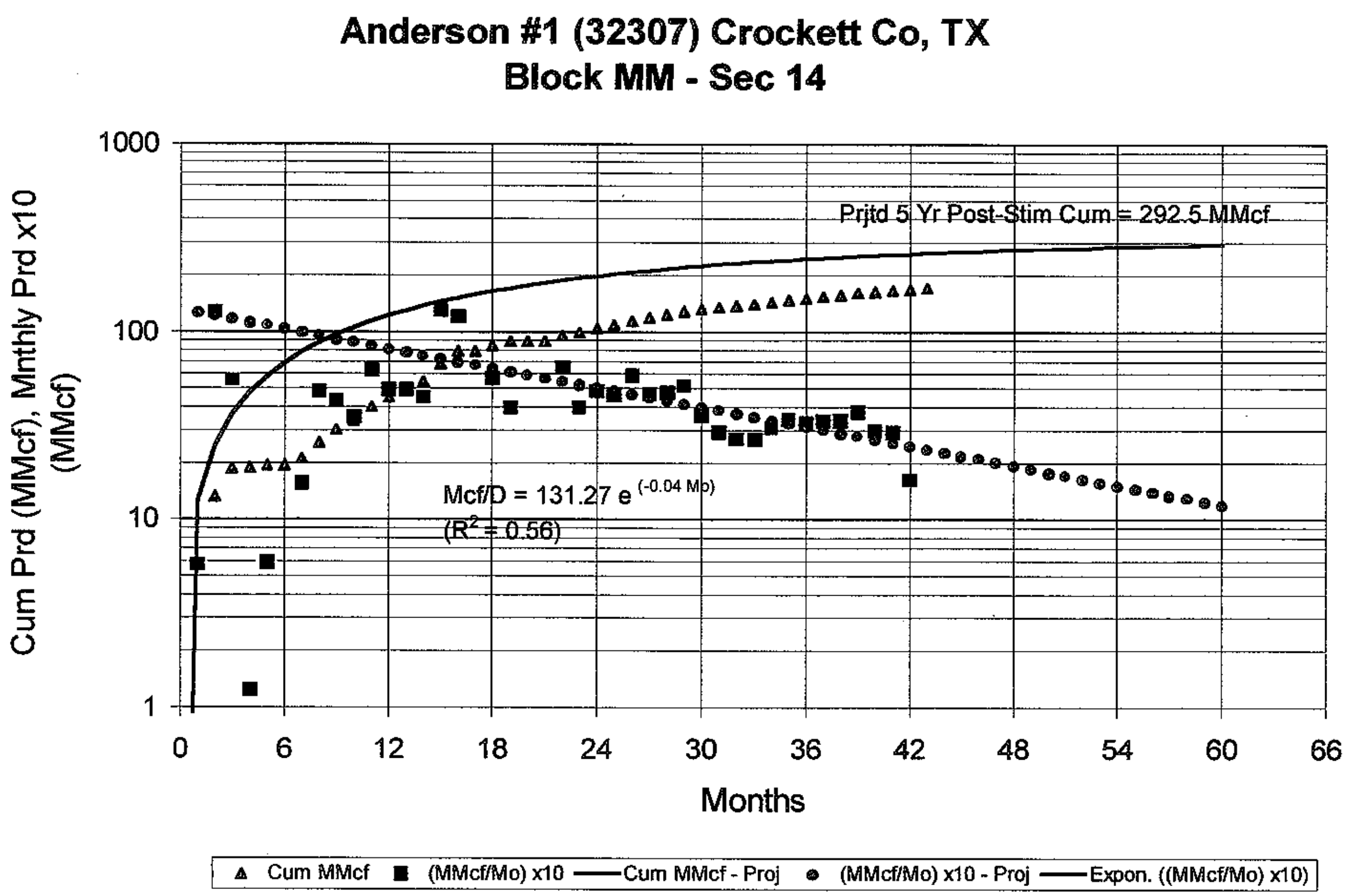
a. Control Well # 1 - Hatton 03-13 (32174) - Projected 5 Yr Prod 434.2 MMcf



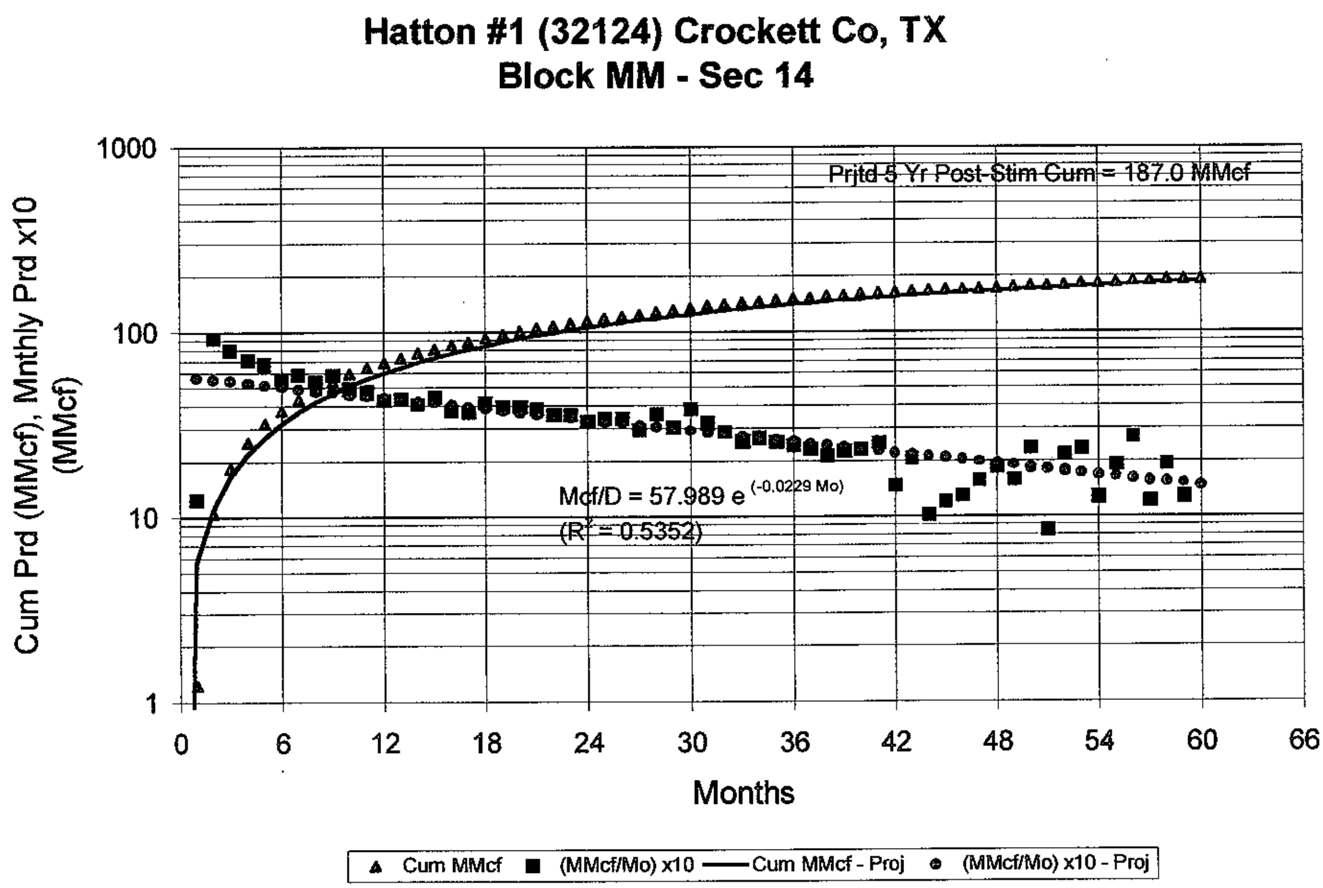
b. Control Well # 2 - Hoover 04-07 (34267) - Projected 5 Yr Prod 332.5 MMcf



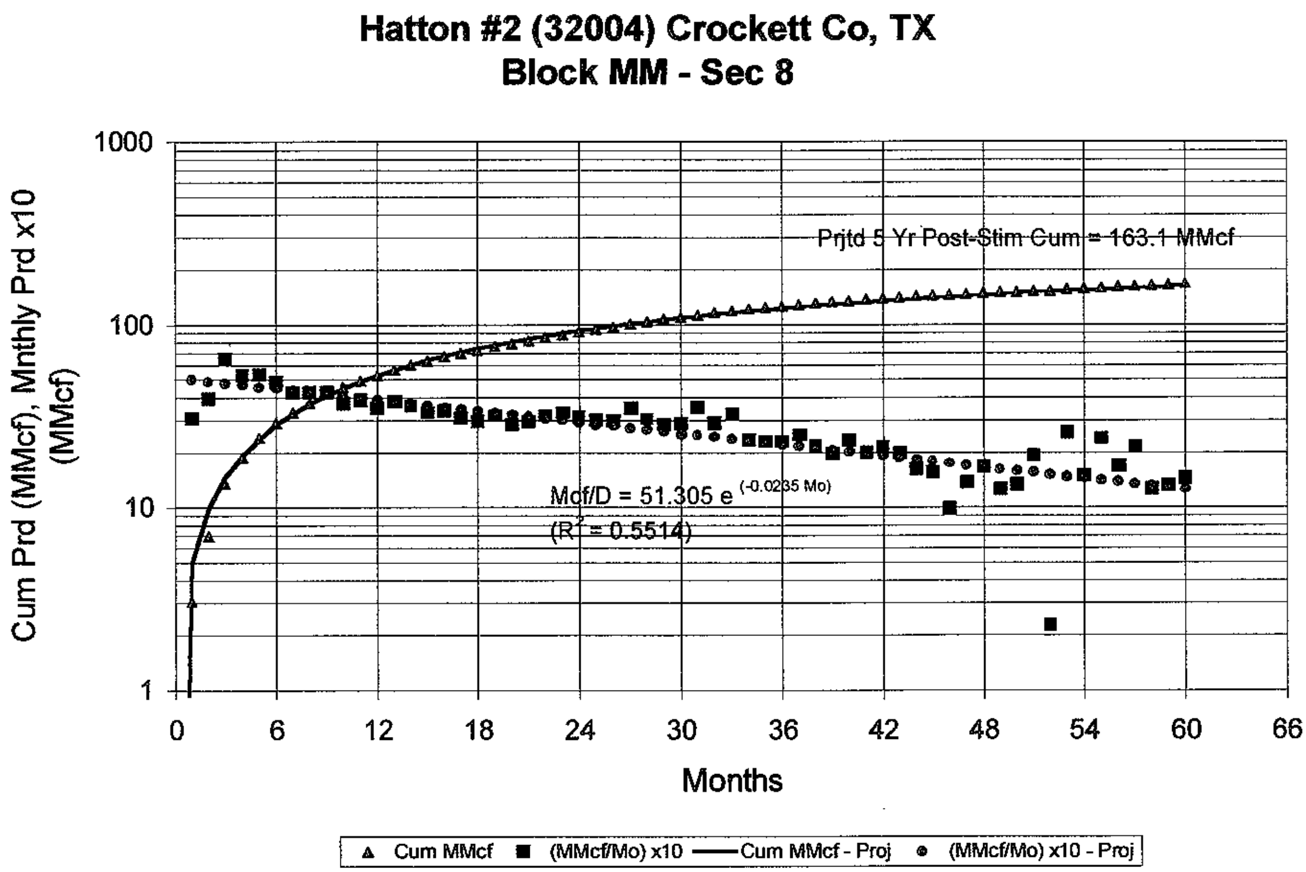
c. Control Well # 3 - Anderson 01-14 (32307) - Projected 5 Yr Prod 292.5 MMcf



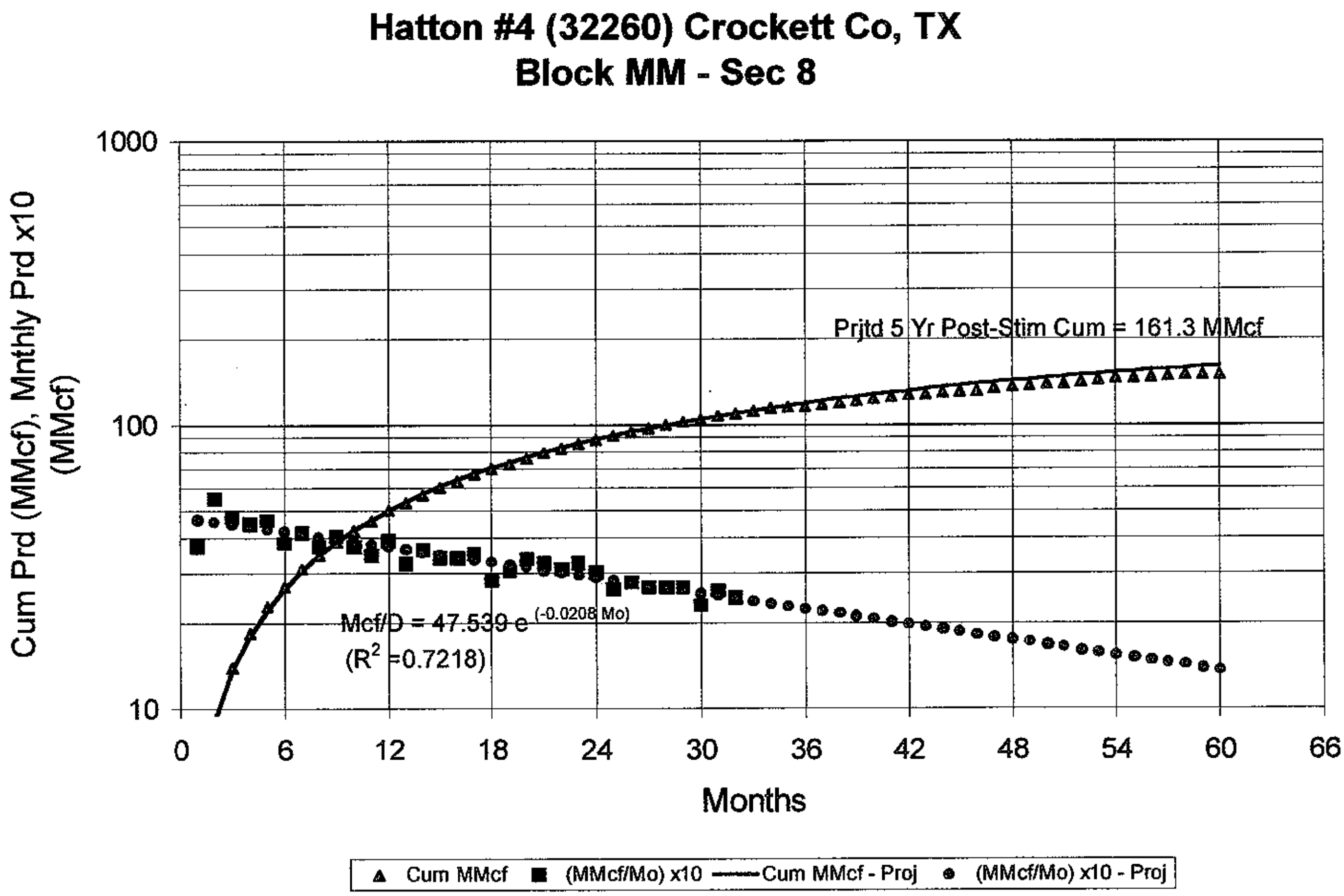
d. Control Well # 4 - Hatton 01-14 (32124) - Projected 5 Yr Prod 187.0 MMcf



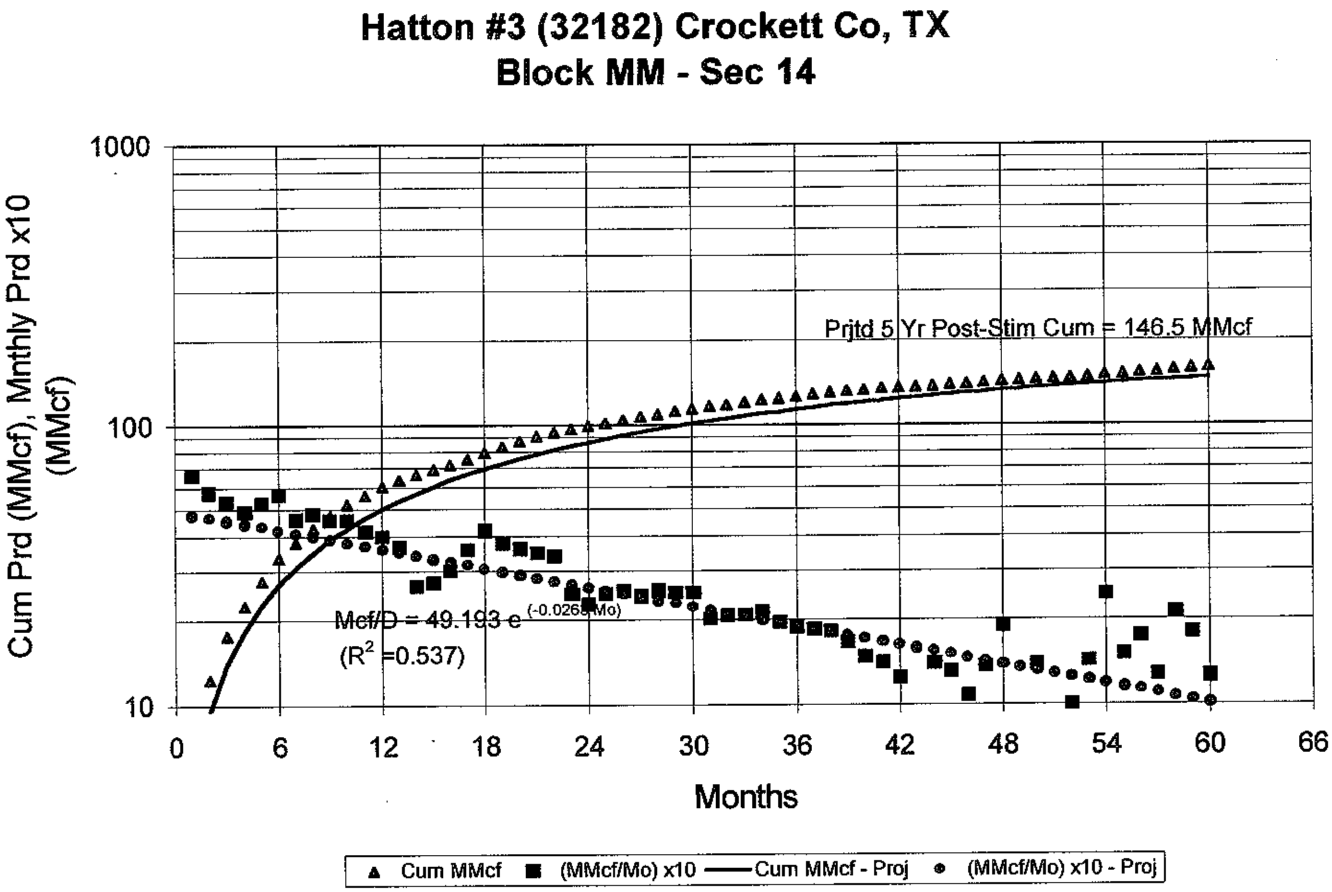
e. Control Well # 5 - Hatton 02-08 (32004) - Projected 5 Yr Prod 163.1 MMcf



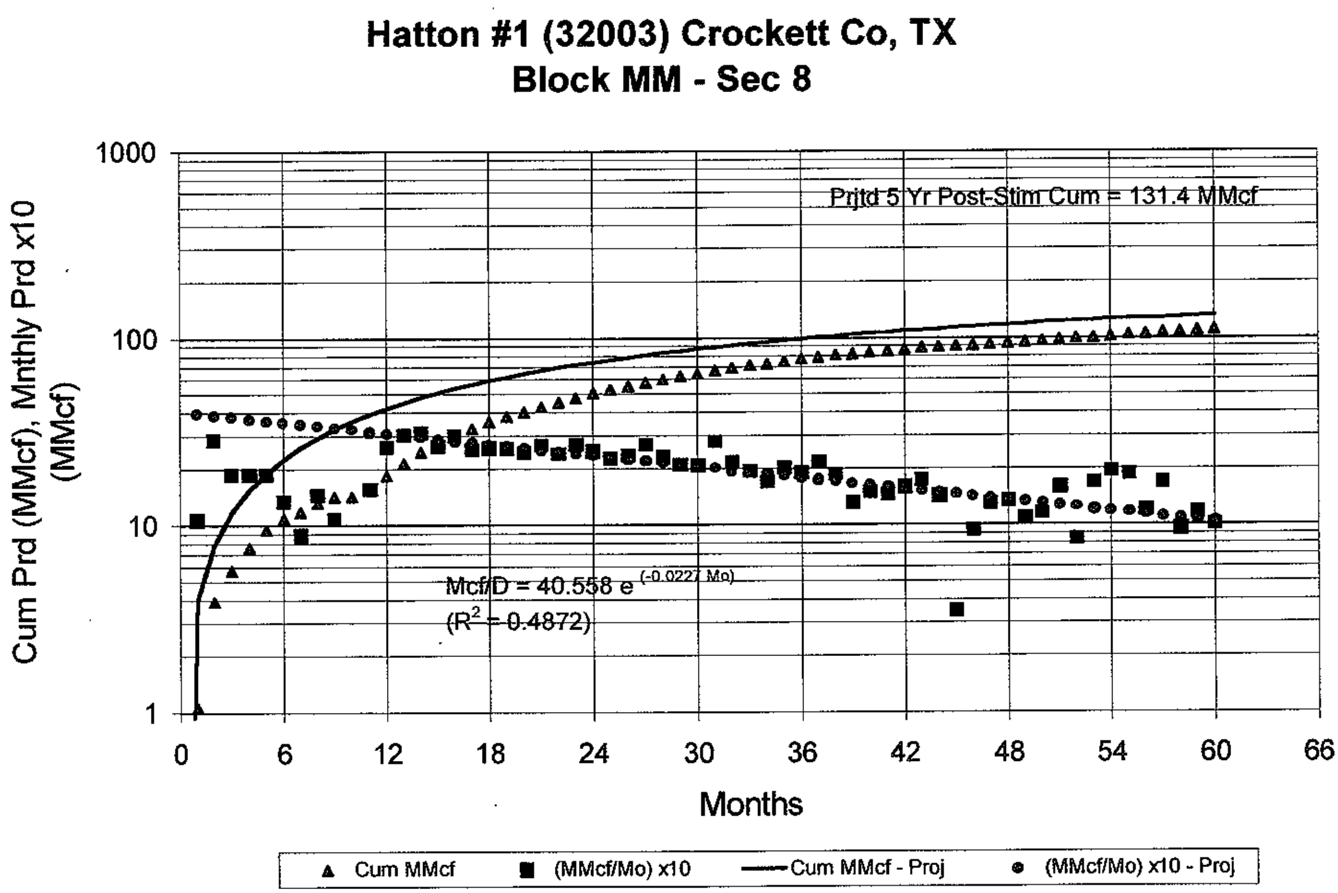
f. Control Well # 6 - Hatton 04-08 (32260) - Projected 5 Yr Prod 161.3 MMcf



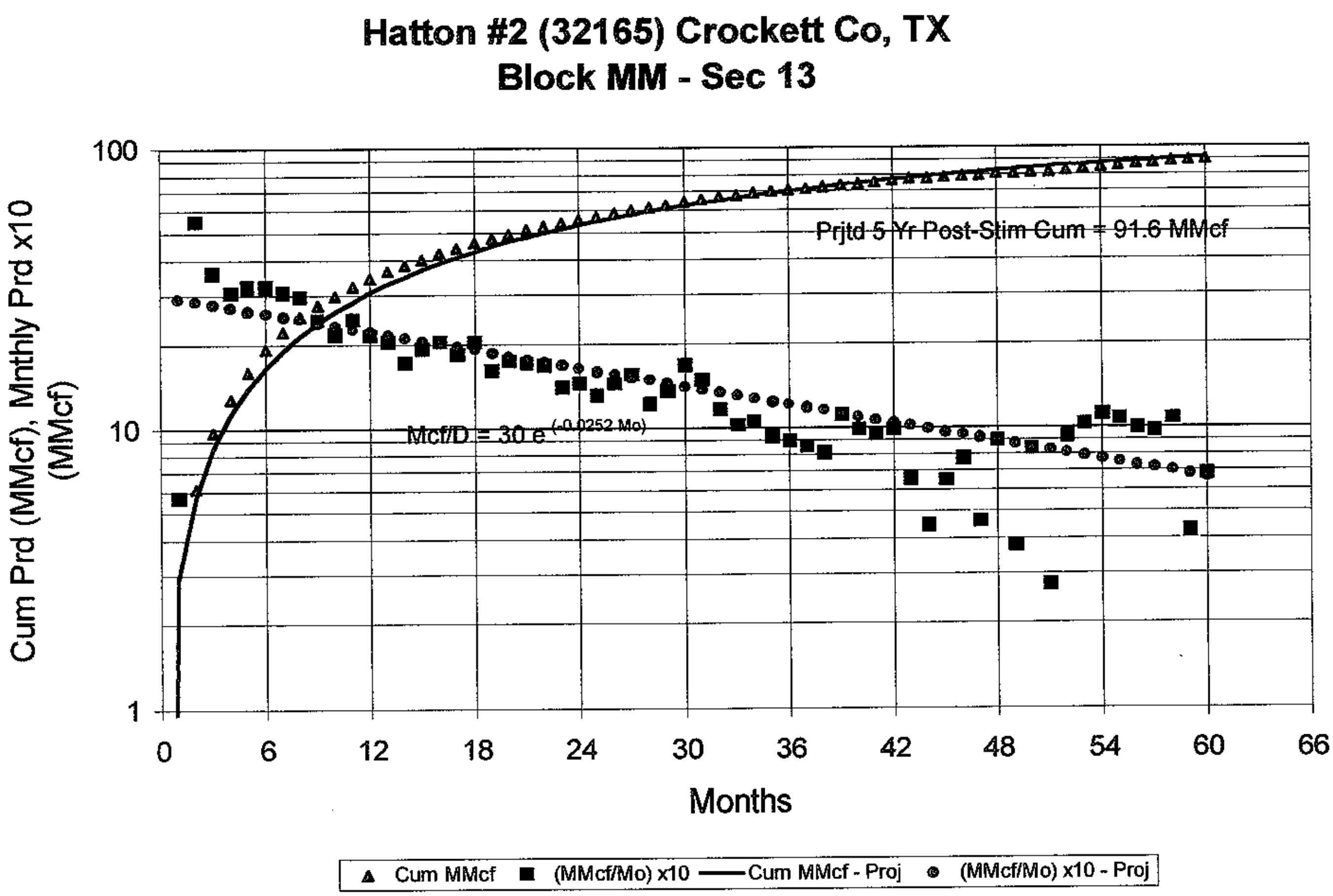
g. Control Well # 7 - Hatton 03-14 (32182) - Projected 5 Yr Prod 146.5 MMcf



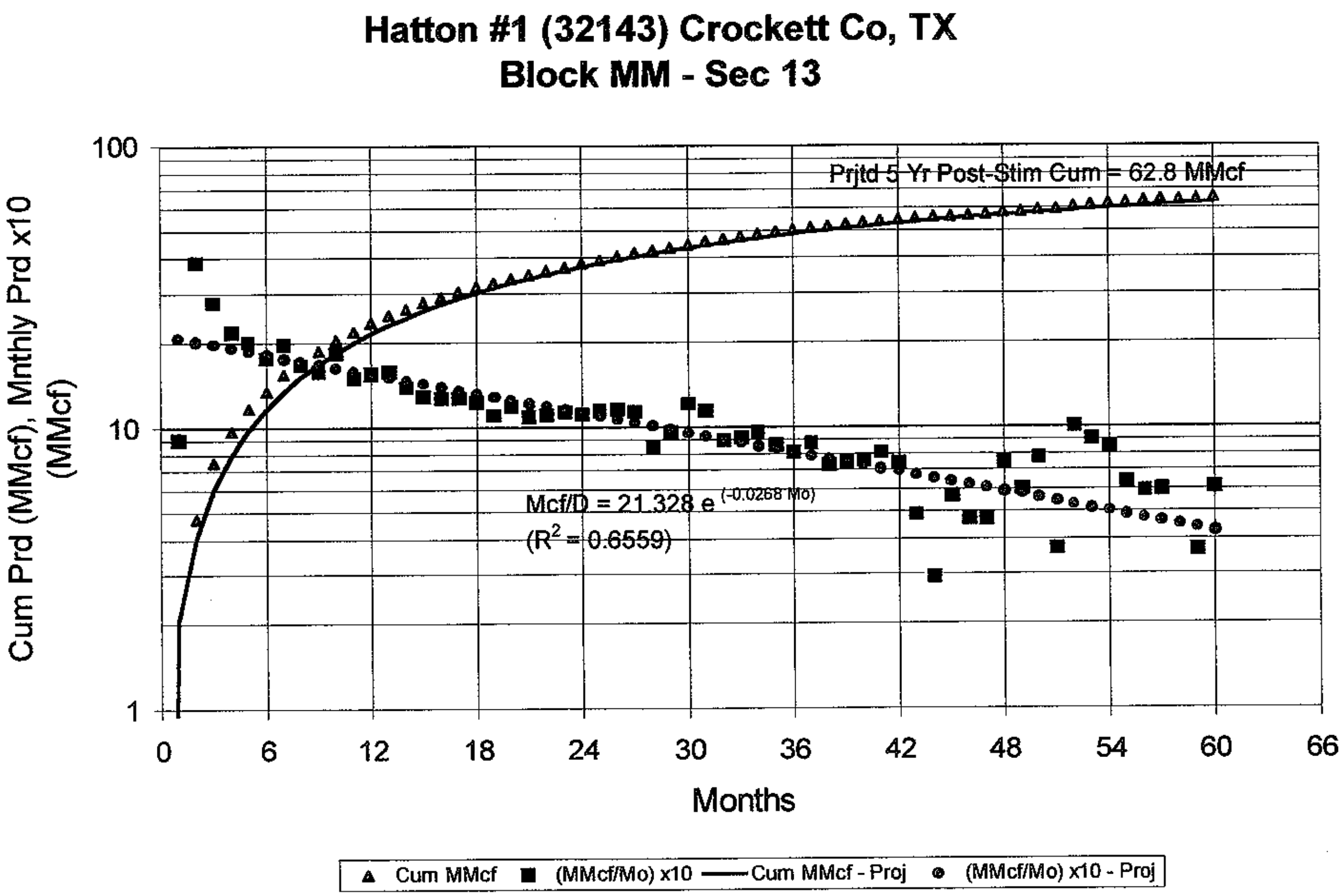
h. Control Well # 8 - Hatton 01-08 (32003) - Projected 5 Yr Prod 131.4 MMcf



i. Control Well # 9 - Hatton 02-13 (32165) - Projected 5 Yr Prod 91.6 MMcf

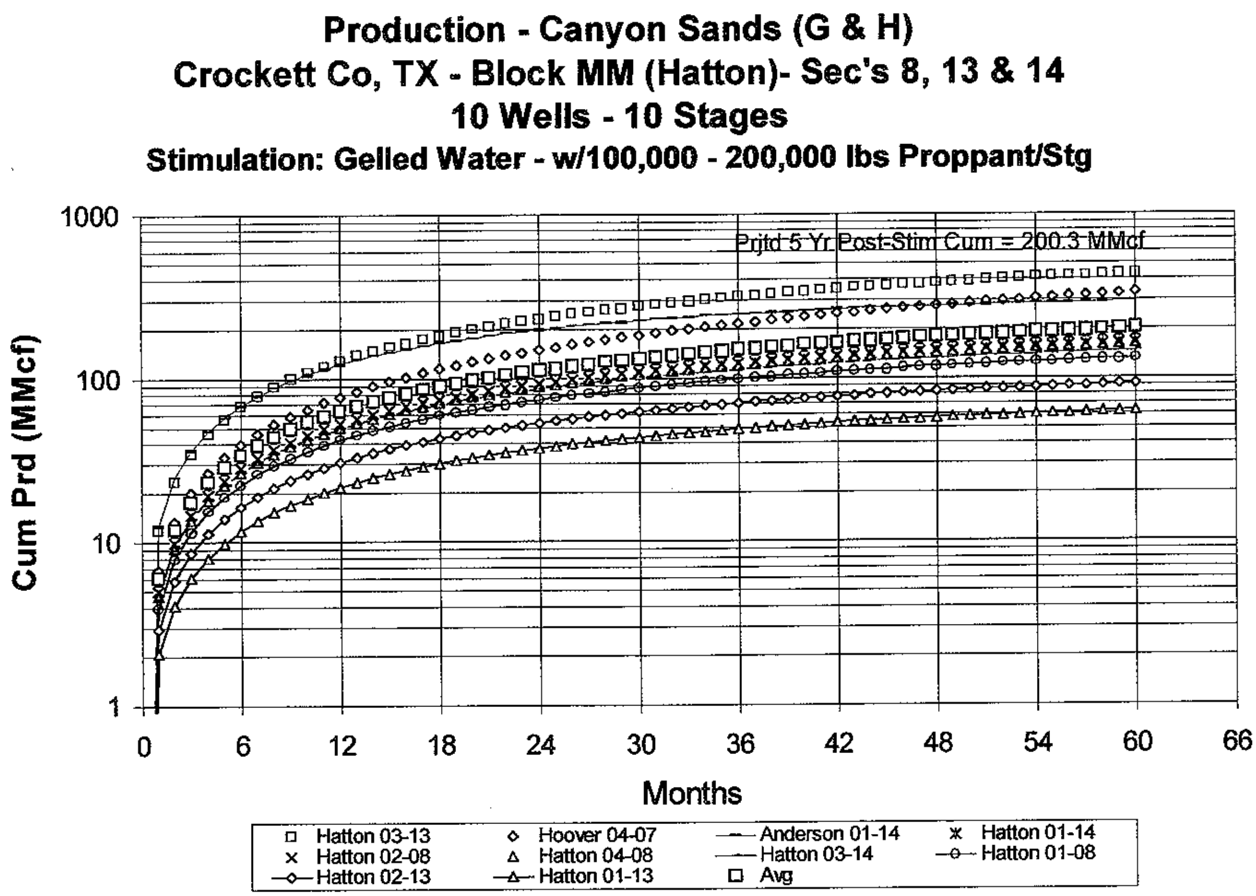


j. Control Well #10 - Hatton 01-13 (32143) - Projected 5 Yr Prod 65.3 MMcf



2. Summary – Control Wells

The five year cumulative production from the ten Control Wells ranged between 62.8 and 434.2 MMcf and averaged 200.3 MMcf.



3. Candidate Well Selection - Three Wells

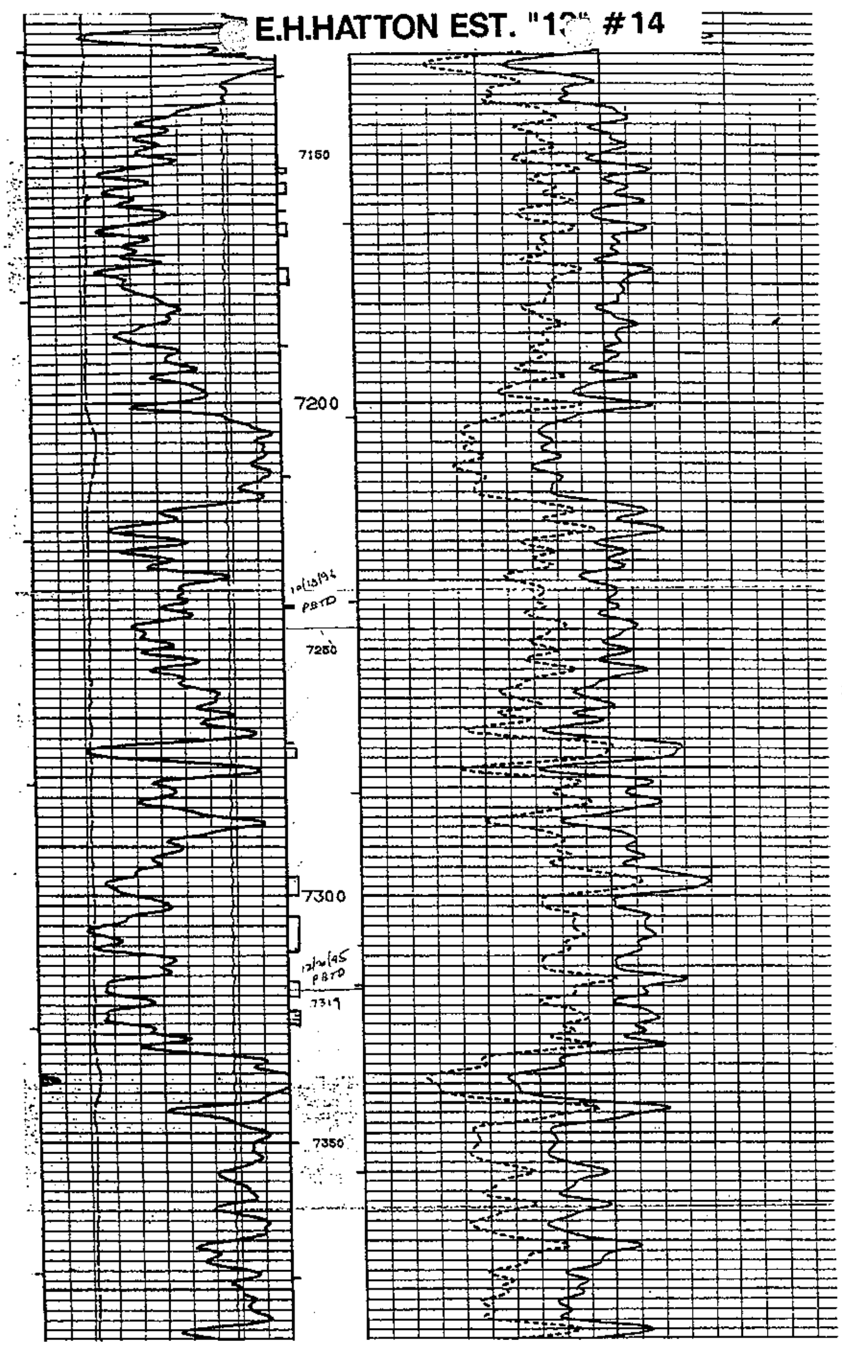
The three Candidate Wells and ten Control Wells situated in test area #2 and all were completed in the G & H Sands and stimulated with a single stage CO_2/sand treatment. The reservoir pressure was approximately 80 to 90% of the original and the EUR's have to exceed 300 million cubic feet of gas equivalence (300 MMcf) to meet the operators minimum economic hurdle.

One of the originally proposed Candidate Wells in Block MM was, because of a robust response to a liquid CO_2 only stimulation, removed at UPRC's request and a replacement substituted.

The originally proposed Candidate Well #3-17 was removed because of its unusually large response to a 577 bbl (107 tons) CO_2 only stimulation. The original plan was to initially treat it with CO_2 only, monitor the production, and then stimulate it with the CO_2/Sand process. Because the production response has been favorable, it was requested that another well, #7C-7, be exchanged for #3-17.

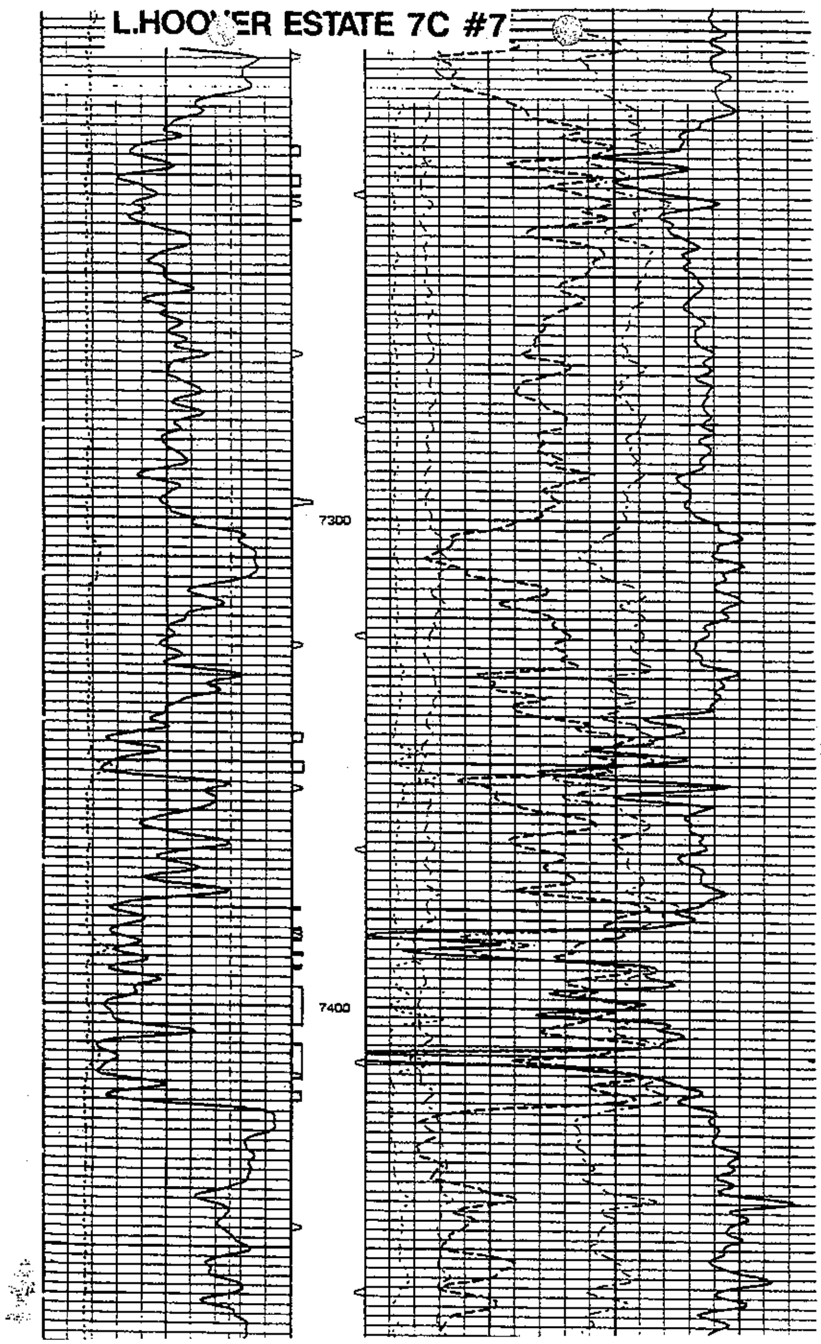
a. Candidate Well #1 - Hatton 13-14 (36848)

The electric log indicating the perforated intervals follows below.



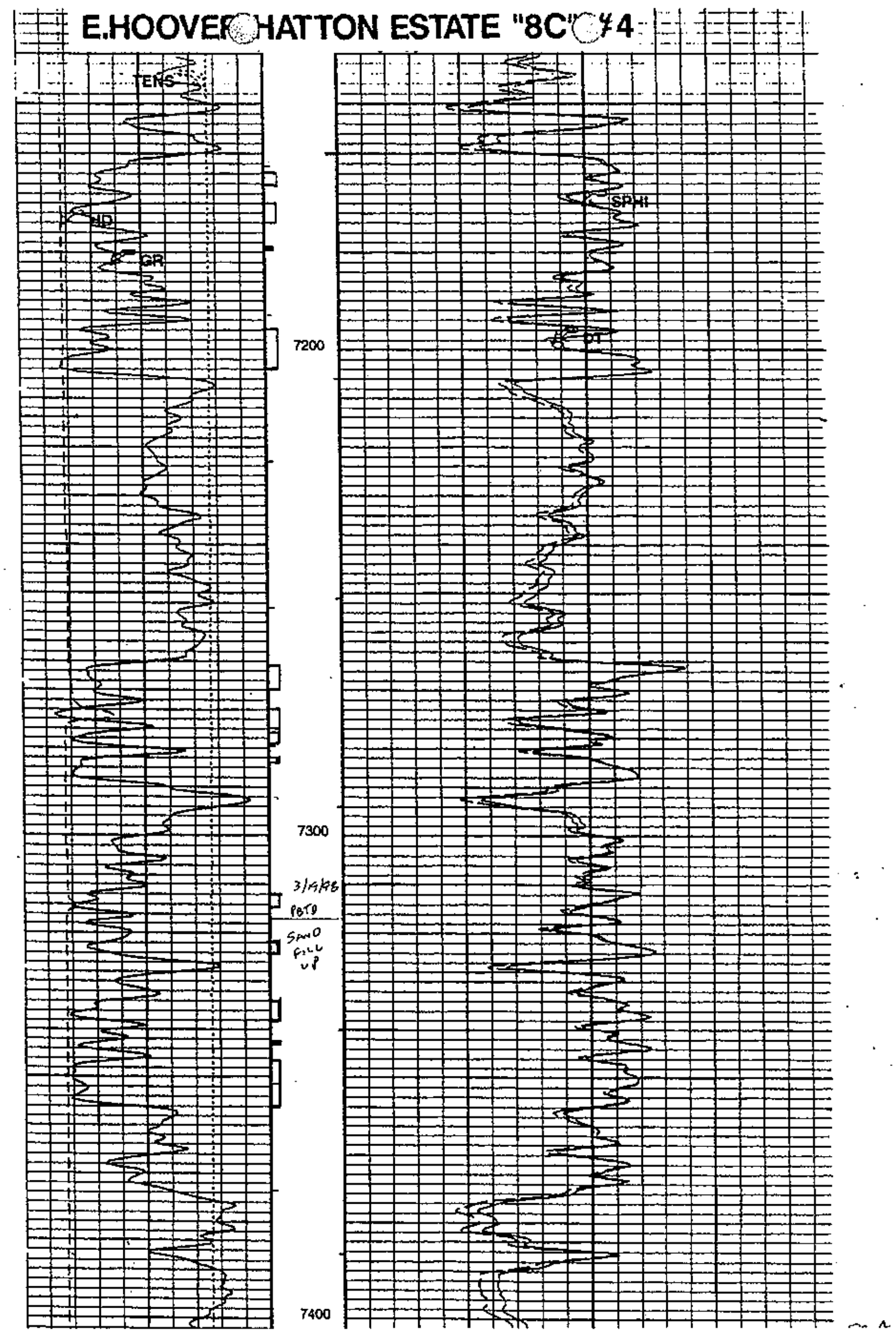
b. Candidate Well #2 - Hatton 7C-7 (36960)

The electric log indicating the perforated intervals follows below.



c. Candidate Well #3 - Hatton 8C-14 (36991)

The electric log indicating the perforated intervals follows below.



4. Field Activities

a. Stimulations

These treatments were performed immediately following those of three other Candidate Wells situated in Block NG (Montgomery) which were each stimulated with two-stage CO_2/sand treatments. During those treatments it became evident that the maximum pumping rate would be 40 barrels per minute as limited by a maximum allowable well head treating pressure of 6,500 psi, and that the maximum sand concentrations for this rate would be less than three pounds per gallon

A summary of the perforation, stimulation specifics (volumes, rates, pressures) for all three of the Candidate wells is below and the individual job summary logs and rate-pressure-sand concentration plots for each well are also included as noted below.

PETROLEUM CONSULTING SERVICES
P.O. BOX 35833
CANTON, OH 44735
(216) 499-3823

STIMULATION SUMMARY

DATE: 12/29/95 PAGE 1 OF 2

WELL:	HATTON 7C-7	HATTON 8C-4	HATTON 13-14
TARGET:	L CANYON	L CANYON	L CANYON
SEC/BLK:	7/MM	8/MM	13/MM
SURVEY:	T & STL RR	T & STL RR	T & STL RR
F?L/F?L:	430S/330E	660S/2080E	1500N/467W
CO/ST:	CROCKETT/TX	CROCKETT/TX	CROCKETT/TX
PMT #(42-105)	36960	36991	36848
OPERATOR:	UPRC	UPRC	UPRC
ELEV GL:	2409	2375	2378
TOT DPTH:	7585	7613	7525
COMPLTED:	11/03/95	09/19/95	09/04/95
STIMULATED:	12/15/95	12/15/95	12/15/95
PERFS:	63	71	56
TOP:	7224	7164	7153
BOT:	7420	7356	7326
INTERVAL:	196	192	173
ACID(GAL):	0	0	0
CO2(BBLS):	640	659	466
(TONS):	104	125	75
TOTAL:	149	165	119
PAD(BBLS):	198	205	143
SL(BBLS):	315	328	288
FLUSH(BBLS):	127	126	35
PMP(BBLS):	640	659	466
SAND(SXS):	112	140	139
IN WELL:	10	23	83
NET(SXS):	102	117	56
MESH:	20/40	20/40	20/40
N2 (MCF):	104	15	97
RATE(BPM)			
AVG:	39.5	40.0	39.0
MAX:	42.0	42.0	42.0
PRESS(PSI)			
AVG:	5800	5800	6600
MAX:	6050	6250	7400
SND CONC(PPG)			
AVG:	0.8	1.0	1.1
MAX:	1.0	2.0	2.0
HORSEPOWER			
AVG:	5615	5686	6309
MAX:	6228	6434	6794

12/29/95 PAGE 2 OF 2

WELL:	HATTON 7C-7	HATTON 8C-4	HATTON 13-14	
BRK DWN(PSI):				
PRE ISIP(PSI)	6050	5900	6775	
RATE(BPM):	42.5	40.5	40.8	
ISIP(PSI):	3624	3324	3103	
GRAD (PSI/FT)	0.49	0.46	0.43	
F(PSI/100FT):	22	24	34	
2 MIN(PSI):	3200			
3 MIN(PSI):		3224		
AVG SC*SL(SXS	112	140	139	
PRESS AT PERFS:				
@MAX P(PSI)	8847	9137	10370	
@AVG P(PSI)	8586	8586	9427	
AVG(PSI):	8717	8862	9899	
LIQ (PSI/FT):	0.38	0.39	0.40	
SG:	0.88	0.90	0.92	
CO2 YLD(BBL/T	6.2	5.3	6.2	
PRESS:				
OPN FLO:				
TIL:				
MCFD				
AVG:				
RECENT:				
FROM:				
			SCREENOUT w/56 SXS IN ZONE AVG SC IN ZONE=0.69	
PUMPING($)	8666	8666	8666	
N2	2933	724	2935	
SAND	1248	3946	1846	
MISC	2447	2638	2481	
	15294	15974	15928	47196
CO2	9685	10725	7735	
CO2-PORTABLES	200	200	200	
BLENDER	6000	6000	6000	
LISC FEE	5000	5000	5000	
TUBE TRLR	5500	5500	5500	
	26385	27425	24435	78245
MOB,PDIEM:			800	
TRCKNG				
MISC	79	80	100	
TOT	41758	43479	41263	126500
$/SK	409	372	737	

(1) Candidate Well #1 - Hatton 13-14 (36848)

The well was perforated with 56 holes over a 173 foot interval from 7,153 to 7,326 feet.

The pressurized blender was transported to the well site on the day of the treatment, December 15, 1995 and filled with 20/40 Brady sand. The treatment was then executed, 13,900 lbs of proppant were pumped at an average rate and pressure of 34.0 (39-5) barrels per minute and 6,600 psi respectively. The maximum sand concentration was 2.0 lbs per gal, and averaged 1.1, the maximum rates and pressures were 42.0 Bpm and 7,400 psi (screen out) respectively. The instantaneous shut in pressure was 3,103 psi which results in a gradient of 0.43 psi/ft. The stimulation pressure-rate history plot is included.

The pumping operation was terminated because of a screen out. It was being pumped at 39 bpm and a good deal of CO_2 leakage around the piston rod packings (12 pumps) reduced the injection rate by an estimated 5 bpm resulting in an actual through-wellhead rate of 34 bpm. The in zone proppant volume was estimated 5,600 pounds.

HALLIBURTON ENERGY SERVICES

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CUSTOMER AND JOB INFORMATION

Customer	U.P.O.G	Date	15-Dec-1995
Contractor		County	CROCKETT
Lease	EH HATTON	Town	
Location	OZONA	Section	
Formation	LOWER CANYON	Range	
Job Type	CO2	Permit No	
Country	U.S.A.	Well No	13-14
State	TEXAS	Field Name	

Customer Representative FRED MCDOUGAL   Halliburton Operator DALE PUTNAM   Ticket No. 838878

STAGE DESCRIPTIONS

PRIME & TEST
PAD
.5 PPG 20/40
1 PPG 20/40
2 PPG 20/40
FLUSH

WELL CONFIGURATION INFORMATION

Packer Type   Depth 0 ft
Bottom Hole Temp. 91.0 Deg F

PIPE CONFIGURATION

Wellbore Segment Number	Measured Depth (ft)	TVD (ft)	Casing ID (inch)	Casing OD (inch)	Tubing ID (inch)	Tubing OD (inch)
1	7326	7326	3.950	4.500	0.000	0.000

PERFORATIONS

Perforation Interval	Top (ft)	Bottom (ft)	Shots per (ft)
1	7153	7326	0

REMARKS ABOUT JOB

FRACTURE LOWER CANYON

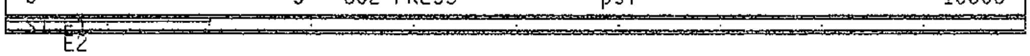
THANK YOU

HALLIBURTON ENERGY FRAC CREW

####################
PLAYBACK STRIP CHART
####################

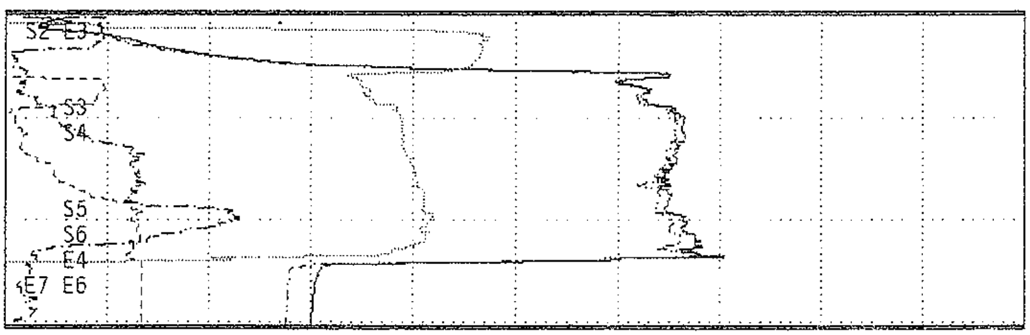
1. Casing Press (psi)
2. Slurry Rate 1 (bpm)
3. Casing Press (psi) Avg for Stg
4. Slurry Rate (bpm) Avg for Stg

0	————	1	CASING PRESS	psi	————	10000
0.00	········	2	SLURRY RATE 1	bpm	········	100.00
0.00	—·—·—·	3	SAND CONC	lb/gal	—·—·—·	10.00
0.00	-------	4	FLUID CONC/BH	lb/gal	-------	10.00
0	-·-·-·-	5	CO2 PRESS	psi	-·-·-·-	10000



07:25:54

PAUSE



08:01:49
419
0.00
416
0.00

08:11:49
6628
41.63
6537
08:16:56

Customer: U.P.O.G
Well Desc: EH HATTON 13-14
Formation: LOWER CANYON

Date: 15-Dec-1995
Ticket #: 838878
Job Type: CO2

JOB SUMMARY

JOB START TIME: 07:25:28
JOB END TIME: 08:16:56
JOB DURATION: 00:51:28

STAGES AND EVENTS:

Chart		Time	Slurry Rate (bpm)	Slurry Stage Volume (gal)	Casing Press. (psi)	Remark
Event	#1	07:25:28	0.00	0	0	Start Job
Stage	#1	07:25:43	0.00	0	-1	START COOL DOWN
Event	#2	07:25:54	0.00	0	-1	Pause
Event	#3	08:01:49	0.00	0	419	Resume
Stage	#2	08:01:53	0.00	5669	452	START PAD
Stage	#3	08:05:29	35.11	2085	6262	START .5 PPG
Stage	#4	08:06:50	38.83	6924	6632	START 1 PPG
Stage	#5	08:10:59	41.04	3176	6475	START 2 PPG
Stage	#6	08:12:48	40.84	1402	6775	START FLUSH
Event	#4	08:13:54	0.00	0	3220	SCREENED OUT
Event	#5	08:14:11	0.00	0	3103	ISIP Casing Press 3103 (psi)
Event	#6	08:14:17	0.00	0	3074	165 SKS SAND PUMPED
Event	#7	08:14:35	0.00	0	3059	1400 GAL FLUSH BEFORE SCREEN ED OUT
Event	#8	08:16:56	0.00	0	2999	End Job

Customer:	U.P.O.G	Date:	15-Dec-1995
Well Desc:	EH HATTON 13-14	Ticket #:	838878
Formation:	LOWER CANYON	Job Type:	C02

STAGE SUMMARY

Stage Times

Stage	Start Time	End Time	Elapsed Time
1	07:25:43	08:01:53	00:36:10
2	08:01:53	08:05:29	00:03:36
3	08:05:29	08:06:50	00:01:21
4	08:06:50	08:10:59	00:04:09
5	08:10:59	08:12:48	00:01:49
6	08:12:48	08:16:56	00:04:08
Total	07:25:43	08:16:56	00:51:13

AVERAGES OR VOLUMES PER STAGE -- Planned Volume vs. Actual Volume

Stage	Planned Sl Volume (gal)	Slurry Volume (gal)
1	1000	0
2	6000	5669
3	2045	2085
4	7319	6924
5	6547	3176
6	5280	1402
Tot/Avg	28191	19256

AVERAGES OR VOLUMES PER STAGE -- Strip Chart Variables

Stage	Casing Pressure (psi)	Prop Conc Slurry* (lb/gal)	Prop Conc Bottom* (lb/gal)	C02 Pressure (psi)
1	416	0.98	0.00	308
2	3022	0.44	0.94	2961
3	6417	0.37	0.46	6362
4	6538	1.10	0.41	6454
5	6620	1.90	1.28	6491
6	3906	0.53	1.24	3673
Tot/Avg	1756	0.92	0.73	1644

*Average based on volume.

Customer: U.P.O.G
Well Desc: EH HATTON 13-14
Formation: LOWER CANYON

Date: 15-Dec-1995
Ticket #: 838878
Job Type: CO2

STAGE SUMMARY

MAXIMUM VALUE PER STAGE -- Strip Chart Variables

Stage	Casing Pressure (psi)	Prop Conc Slurry* (lb/gal)	Prop Conc Bottom* (lb/gal)	CO2 Pressure (psi)
1	431	0.99	0.00	318
2	6532	0.98	0.97	6657
3	6655	0.51	0.91	6569
4	6663	1.40	1.23	6595
5	6809	2.33	1.33	6657
6	7368	1.39	1.33	6820
Max Job	7368	2.33	1.33	6820

(2) Candidate Well #2 - Hatton 7C-7 (36960)

The well was perforated with 63 holes over a 196 foot interval from 7,224 to 7,420 feet.

The pressurized blender was transported to the well site on the day of the treatment, December 15, 1995 and filled with 20/40 Brady sand. The treatment was then executed, 11,200 lbs of proppant were pumped at an average rate and pressure of 39.5 barrels per minute and 5,800 psi respectively. The maximum sand concentration was 1.0 lbs per gal, and averaged 0.8, the maximum rates and pressures were 42.0 Bpm and 6,228 psi respectively. The instantaneous shut in pressure was 3,624 psi, which results in a gradient of 0.49 psi/ft. The stimulation pressure-rate history plot is included. The in zone proppant volume was estimated 10,200 pounds.

HALLIBURTON ENERGY SERVICES

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CUSTOMER AND JOB INFORMATION

Customer	U.P.O.G	Date	15-Dec-1995
Contractor		County	CROCKETT
Lease	HOVER HAT	Town	
Location	OZONA	Section	
Formation	LOWER CANYON	Range	
Job Type	CO2	Permit No	
Country	U.S.A.	Well No	7c #7
State	TEXAS	Field Name	

Customer Representative FRED MCDOUGAL   Halliburton Operator DALE PUTNAM   Ticket No. 838879

STAGE DESCRIPTIONS

PRIME & TEST
PAD
.5 PPG 20/40
1 PPG 20/40
FLUSH

WELL CONFIGURATION INFORMATION

Packer Type   Depth 0 ft
Bottom Hole Temp. 91.0 Deg F

PIPE CONFIGURATION

Wellbore Segment Number	Measured Depth (ft)	TVD (ft)	Casing ID (inch)	Casing OD (inch)	Tubing ID (inch)	Tubing OD (inch)
1	7420	7420	3.950	4.500	0.000	0.000

PERFORATIONS

Perforation Interval	Top (ft)	Bottom (ft)	Shots per (ft)
1	7224	7420	0

REMARKS ABOUT JOB

FRACTURE LOWER CANYON

THANK YOU
HALLIBURTON ENERGY FRAC CREW

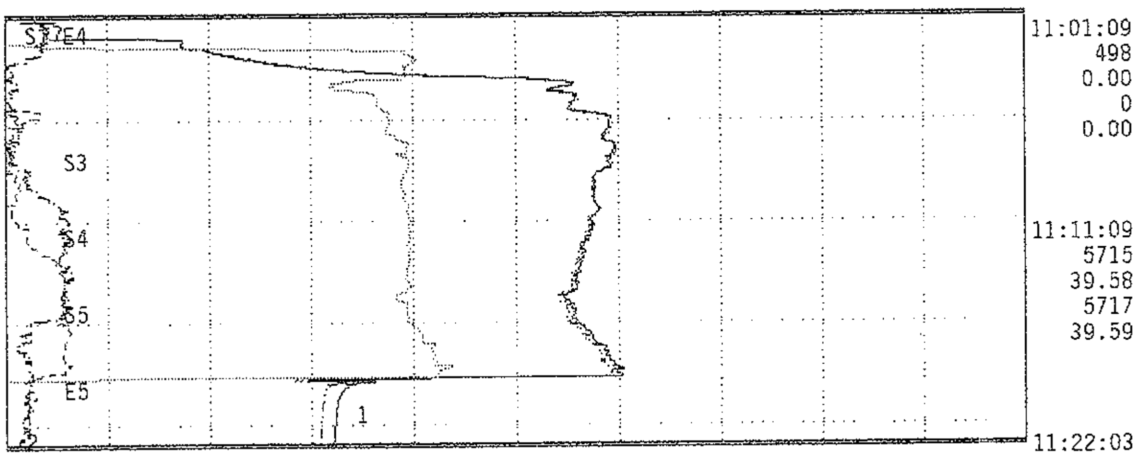
####################
PLAYBACK STRIP CHART
####################

1. Casing Press (psi)
2. Slurry Rate 1 (bpm)
3. Casing Press (psi) Avg for Stg
4. Slurry Rate (bpm) Avg for Stg

0	1	CASING PRESS	psi	10000
0.00	2	SLURRY RATE 1	bpm	100.00
0.00	3	SAND CONC	lb/gal	10.00
0.00	4	FLUID CONC/BH	lb/gal	10.00
0	5	CO2 PRESS	psi	10000

E3 10:38:14

PAUSE



Customer:	U.P.O.G	Date:	15-Dec-1995
Well Desc:	HOVER HAT 7c #7	Ticket #:	838879
Formation:	LOWER CANYON	Job Type:	CO2

JOB SUMMARY

JOB START TIME:	10:37:57
JOB END TIME:	11:22:03
JOB DURATION:	00:44:06

STAGES AND EVENTS:

Chart		Time	Slurry Rate (bpm)	Slurry Stage Volume (gal)	Casing Press. (psi)	Remark
Event	#1	10:37:57	0.00	0	0	Start Job
Event	#2	10:38:01	0.00	0	167	START COOLDOWN
Event	#3	10:38:14	0.00	0	172	Pause
Event	#4	11:01:09	0.00	0	498	Resume
Stage	#1	11:01:11	0.00	0	476	SKIP
Stage	#2	11:01:17	0.00	8334	478	START PAD
Stage	#3	11:07:46	36.11	5460	5940	START .5 PPG SAND
Stage	#4	11:11:05	39.62	7577	5721	START 1 PPG
Stage	#5	11:15:40	39.36	5350	5578	START FLUSH
Event	#5	11:18:55	0.12	0	3624	ISIP Casing Press 3624 (psi)
Event	#6	11:22:03	0.00	0	3089	End Job

Customer:	U.P.O.G	Date:	15-Dec-1995
Well Desc:	HOVER HAT 7c #7	Ticket #:	838879
Formation:	LOWER CANYON	Job Type:	CO2

STAGE SUMMARY

MAXIMUM VALUE PER STAGE -- Strip Chart Variables

Stage	Casing Pressure (psi)	Prop Conc Slurry* (lb/gal)	Prop Conc Bottom* (lb/gal)	CO2 Pressure (psi)
1	476	0.39	0.00	350
2	5968	0.44	0.34	5985
3	5940	0.63	0.14	5959
4	5757	0.69	0.61	5734
5	6050	0.59	0.63	5989
Max Job	6050	0.69	0.63	5989

(3) Candidate Well #3 - Hatton 8C-4 (36991)

The well was perforated with 71 holes over a 192 foot interval from 7,164 to 7,356 feet.

The pressurized blender was transported to the well site on the day of the treatment, December 15, 1995 and filled with 20/40 Brady sand. The treatment was then executed, 14,000 lbs of proppant were pumped at an average rate and pressure of 40.0 barrels per minute and 5,800 psi respectively. The maximum sand concentration was 2.0 lbs per gal, and averaged 1.0, the maximum rates and pressures were 42.0 Bpm and 6,434 psi respectively. The instantaneous shut in pressure was 3,324 psi which results in a gradient of 0.46 psi/ft. The stimulation pressure-rate history plot is included. The in zone proppant volume was estimated 11,700 pounds.

HALLIBURTON ENERGY SERVICES

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CUSTOMER AND JOB INFORMATION

Customer	U.P.O.G	Date	15-Dec-1995
Contractor		County	CROCKETT
Lease	HOVER HAT	Town	
Location	OZONA	Section	
Formation	LOWER CANYON	Range	
Job Type	CO2	Permit No	
Country	U.S.A.	Well No	8c #4
State	TEXAS	Field Name	

Customer Representative FRED MCDOUGAL   Halliburton Operator DALE PUTNAM   Ticket No. 838890

STAGE DESCRIPTIONS

PRIME & TEST
PAD
.5 PPG 20/40
1 PPG 20/40
2 PPG 20/40
FLUSH

WELL CONFIGURATION INFORMATION

Packer Type   Depth 0 ft
Bottom Hole Temp. 91.0 Deg F

PIPE CONFIGURATION

Wellbore Segment Number	Measured Depth (ft)	TVD (ft)	Casing ID (inch)	Casing OD (inch)	Tubing ID (inch)	Tubing OD (inch)
1	7356	7356	3.950	4.500	0.000	0.000

PERFORATIONS

Perforation Interval	Top (ft)	Bottom (ft)	Shots per (ft)
1	7164	7356	0

REMARKS ABOUT JOB

FRACTURE LOWER CANYON

THANK YOU

HALLIBURTON ENERGY FRAC CREW

####################
REALTIME STRIP CHART
####################

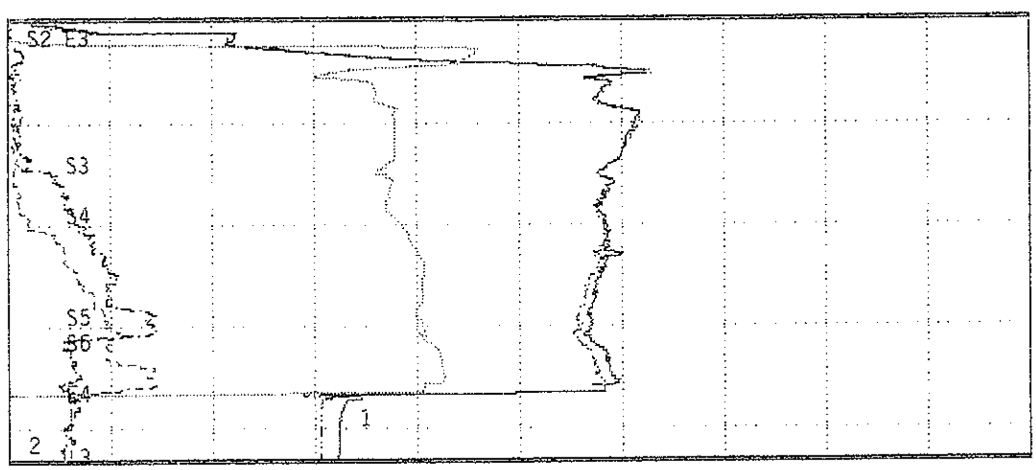
1. Casing Press (psi)
2. Slurry Rate 1 (bpm)
3. Casing Press (psi) Avg for Stg
4. Slurry Rate (bpm) Avg for Stg

0	————	1	CASING PRESS	psi	————	10000
0.00	········	2	SLURRY RATE 1	bpm	········	100.00
0.00	-·-·-·-·	3	SAND CONC	lb/gal	-·-·-·-·	10.00
0.00	--------	4	FLUID CONC/BH	lb/gal	--------	10.00
0	--·--·--	5	CO2 PRESS	psi	--·--·--	10000

E2

13:46:43

PAUSE



14:11:55
461
0.00
158
0.00

14:21:55
5837
38.54
5798
37.61

14:31:55
14:33:21

Customer:	U.P.O.G	Date:	15-Dec-1995
Well Desc:	HOVER HAT 8c #4	Ticket #:	838880
Formation:	LOWER CANYON	Job Type:	CO2

JOB SUMMARY

JOB START TIME:	13:46:23
JOB END TIME:	14:33:21
JOB DURATION:	00:46:58

STAGES AND EVENTS:

Chart		Time	Slurry Rate (bpm)	Slurry Stage Volume (gal)	Casing Press. (psi)	Remark
Event	#1	13:46:23	0.00	0	0	Start Job
Stage	#1	13:46:28	0.00	0	156	COOL DOWN PUMPS
Event	#2	13:46:42	0.00	0	158	Pause
Event	#3	14:11:54	0.00	0	466	Resume
Stage	#2	14:11:57	0.00	8595	459	START PAD
Stage	#3	14:18:21	37.93	3854	6013	START .5 PPG SAND
Stage	#4	14:20:48	36.96	8280	5795	START 1 PPG
Stage	#5	14:25:48	40.40	2254	5717	START 2 PPG SAND
Stage	#6	14:27:07	40.47	5291	5665	START FLUSH
Event	#4	14:30:28	0.00	0	3324	ISIP Casing Press 3324 (psi)
Event	#5	14:33:21	0.00	0	3224	End Job

Customer:	U.P.O.G	Date:	15-Dec-1995
Well Desc:	HOVER HAT 8c #4	Ticket #:	838880
Formation:	LOWER CANYON	Job Type:	CO2

STAGE SUMMARY

Stage Times

Stage	Start Time	End Time	Elapsed Time
1	13:46:28	14:11:57	00:25:29
2	14:11:57	14:18:21	00:06:24
3	14:18:21	14:20:48	00:02:27
4	14:20:48	14:25:48	00:05:00
5	14:25:48	14:27:07	00:01:19
6	14:27:07	14:33:21	00:06:14
Total	13:46:28	14:33:21	00:46:53

/ERAGES OR VOLUMES PER STAGE -- Planned Volume vs. Actual Volume

Stage	Planned Sl Volume (gal)	Slurry Volume (gal)
1	1000	0
2	9000	8595
3	4091	3854
4	8365	8280
5	2182	2254
6	5288	5291
Tot/Avg	29926	28273

AVERAGES OR VOLUMES PER STAGE -- Strip Chart Variables

Stage	Casing Pressure (psi)	Prop Conc Slurry* (lb/gal)	Prop Conc Bottom* (lb/gal)	CO2 Pressure (psi)
1	158	0.01	0.00	161
2	4876	0.08	0.08	4888
3	5859	0.40	0.08	5850
4	5806	0.85	0.51	5742
5	5681	1.35	0.94	5578
6	4493	0.66	1.14	4330
t/Avg	5080	0.56	0.55	5014

*Average based on volume.

Customer:	U.P.O.G	Date:	15-Dec-1995
Well Desc:	HOVER HAT 8c #4	Ticket #:	838880
Formation:	LOWER CANYON	Job Type:	CO2

STAGE SUMMARY

MAXIMUM VALUE PER STAGE -- Strip Chart Variables

Stage	Casing Pressure (psi)	Prop Conc Slurry* (lb/gal)	Prop Conc Bottom* (lb/gal)	CO2 Pressure (psi)
1	461	0.01	0.00	364
2	6268	0.18	0.15	6334
3	6006	0.66	0.12	6006
4	6002	1.09	0.83	5863
5	5722	1.46	1.08	5629
6	5971	1.40	1.44	5826
Max Job	6268	1.46	1.44	6334

(4) Stimulation Summary

One of the three wells (#13-14) screened out and was terminated. It was being pumped at 39 barrels per minute and a good deal of CO_2 leakage around the piston rod packings on the pumps reduced the injection rate. The other two wells were treated without incident and the design sand schedule was achieved, resulting in "in-zone" sand volumes of 5,600, 10,200, and 11,700 pounds, or approximately twelve percent of that placed in conventional treatments.

The following proppant volumes were placed:

Well	Pumped (sacks)	Removed from well (sacks)	Net in zone (sacks)
Hatton 13-14	139	83	56
Hoover 7C-7	112	100	102
Hatton 8C-4	140	23	117

The stimulation treatments are summarized as follows:

	Sand (sacks)		Max Tr Press	Avg Rate	Sand Conc	
Well	Pumped	In-Zone	Psi	BPM	Max	Avg
13-14	139	56	7,400*	39.0	2.0	1.1
7C-7	112	102	6,050	39.5	1.0	0.8
8C-4	140	117	6,250	40.0	2.0	1.0
* Well equipped with P-110 casing						

b. Post Stimulation

(1) Flow Back Procedures

The flow back procedure was initiated immediately following the removal of the stimulation hardware. The flow was restricted with a choke to enable the CO_2 vapor to flow safely. The choke size was increased as the pressure diminished and the CO_2 concentration was monitored. Some sand was produced as was expected because of the intentional under flush.

(2) Cleaning Frac Sand from the Well Bore

Following the stimulations the three Candidate wells were all cleaned by jetting the sand from them with nitrogen gas. The three Candidate wells were as is generally the case with the CO_2/sand stimulations - because of the designed under flush, found to have sand in them above the perforations.

Well	Perf Intvl	Dpth-Top Prf	Sand Top	Fill-up	Clean Out Depth
	(ft)	(ft)	(ft)	(ft) (lbs)	(ft)
Hatton 13-14	7,153 – 7,326	7,153	6,516	147 (8,300)	7,467
Hatton 7C-7	7,224 – 7,420	7,224	7,413	115 (1,000)	7,528
Hatton 8C-14	7,164 – 7,356	7,164	7,349	257 (2,300)	7,613

(3) Tubing Installation

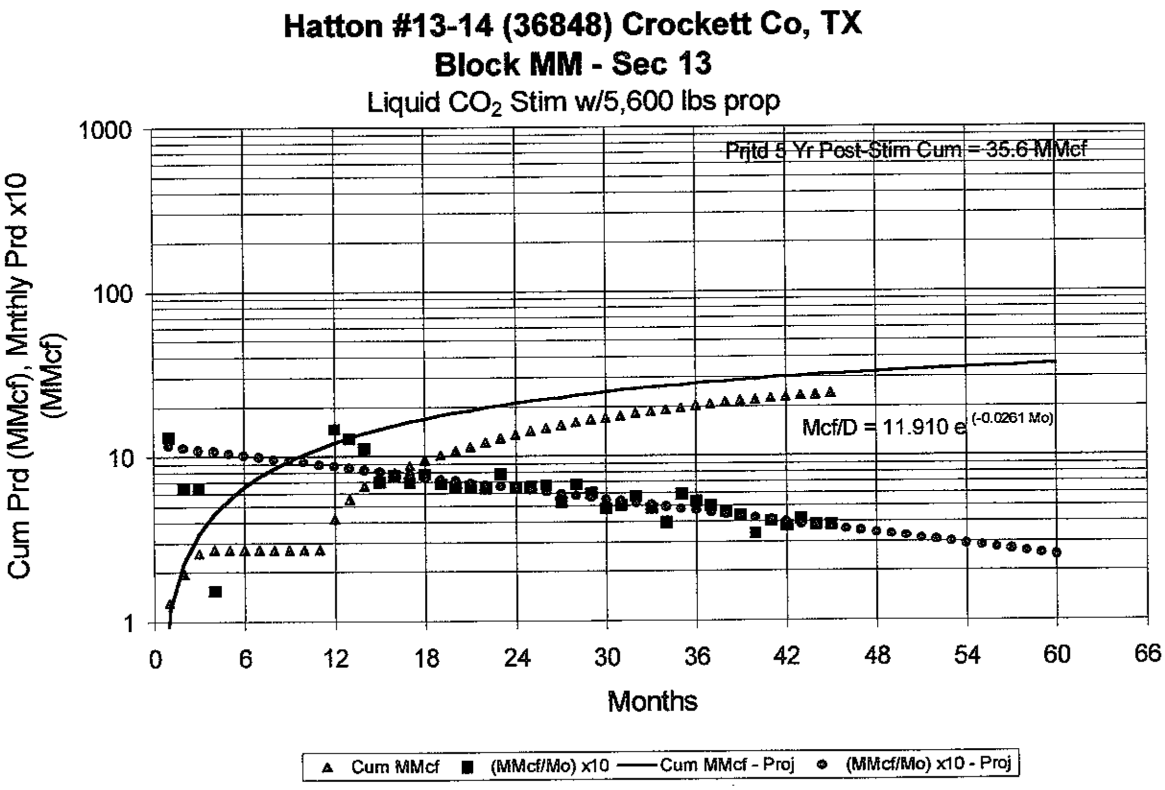
The flowing bottom hole pressures on all three of the CO_2/Sand stimulated wells in the Hoover Hatton area (single stage) were measured. Two of the wells, 7C-7 and 8C-4 had abnormally high flowing bottom hole pressure, 1000-1300 psi. Tubing strings were subsequently planned for these two wells, which were producing at 130 and 70 Mcfd, respectively. The production rates were expected to increase when the tubing is installed. The third well, 13-14, was producing 8 Mcfd and has a flowing bottom hole pressure of 820-850 psi. It was considered as a candidate for re-stimulation but UPRC presently believed that the geology is very poor and that a re-stimulation is unwarranted. The well is between two wells with reasonably good production, no plans are being made either to install tubing or re-stimulate the well.

The production from wells in the Hoover Hatton area increased approximately 20% following the installation of tubing.

5. Results - Production Comparisons

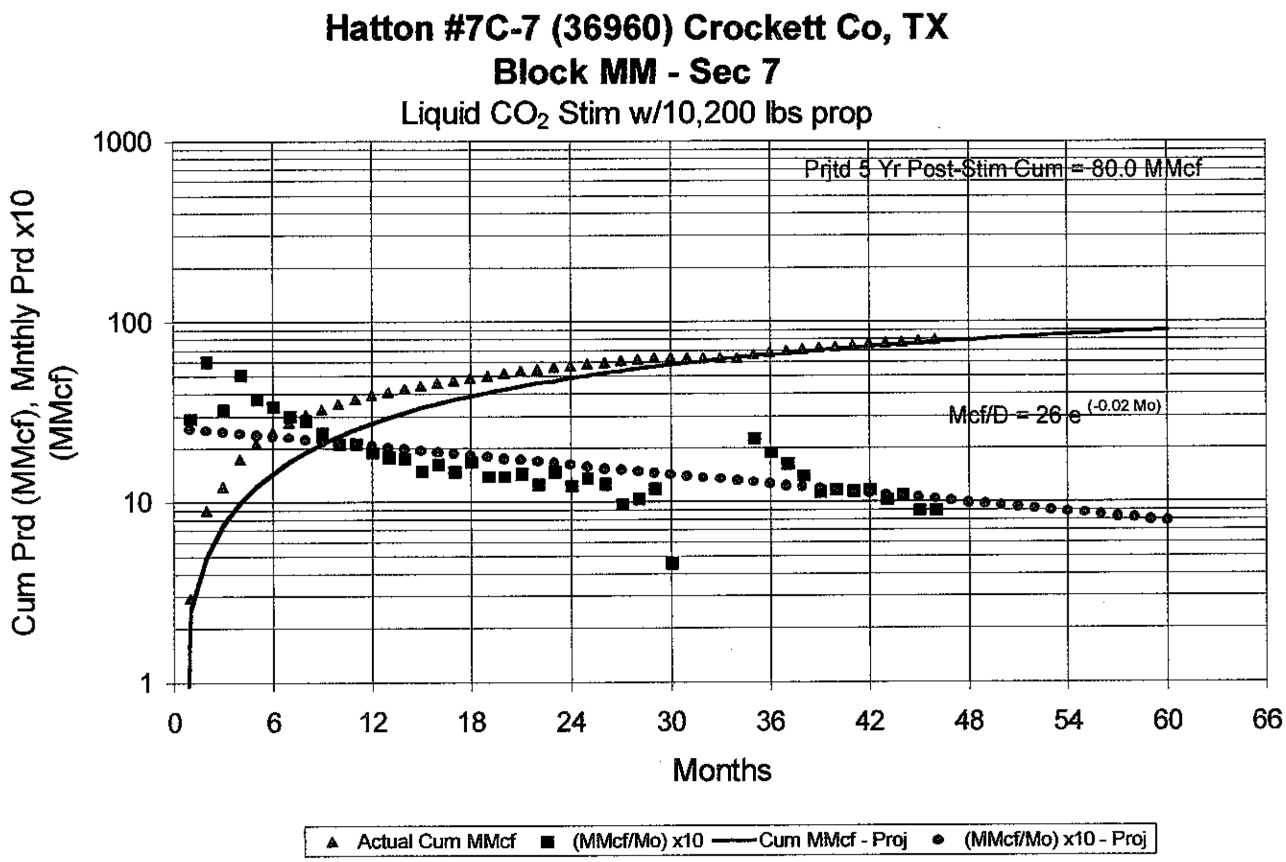
a. Candidate Well #1 - Hatton 13-14 (36848)

Well 13-14 had poor geology and poor production from the outset. Apparently tubing was not installed although it was reported to have been.

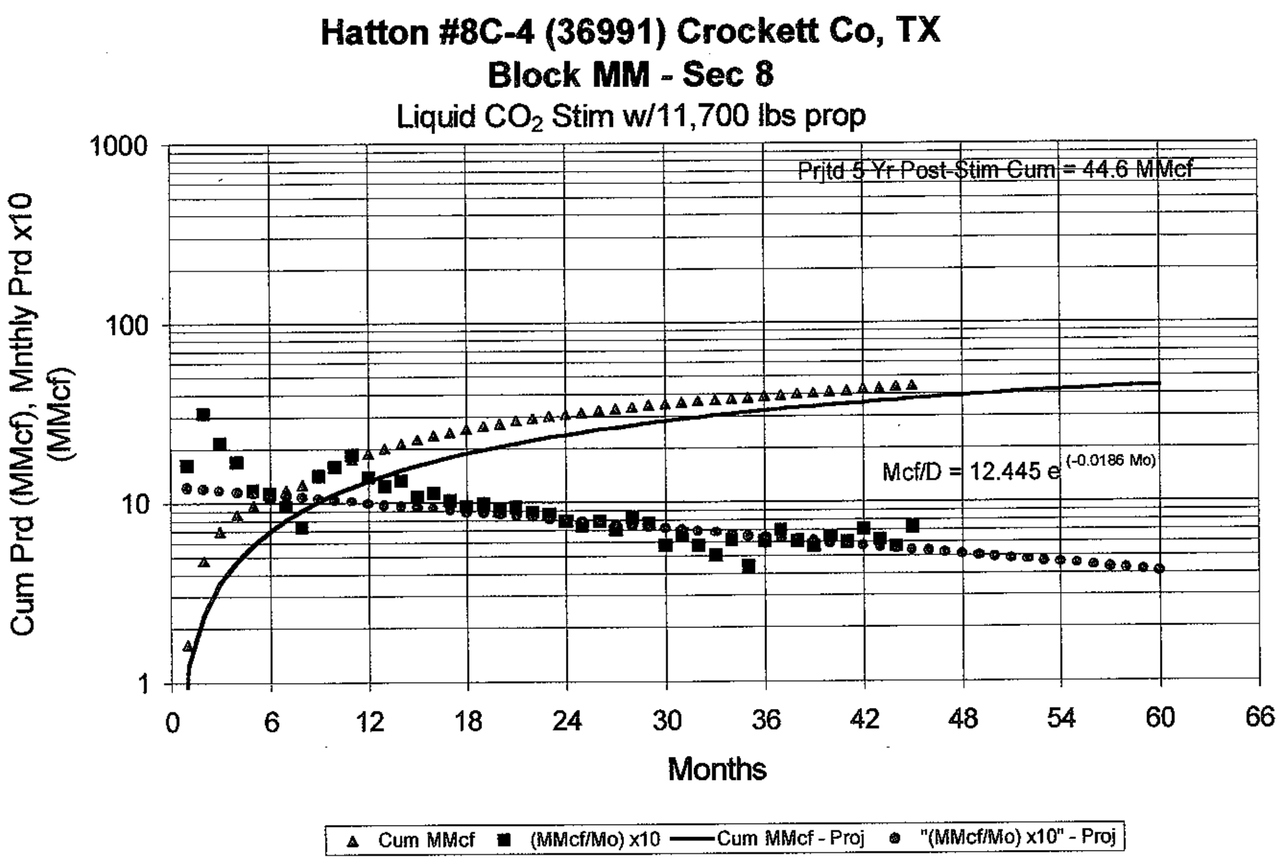


Hatton 13-14 was re-stimulated following the May 1996 approval by the DOE. It was stimulated with 584 sacks of sand in 4,238 barrels of gelled water. A previously unstimulated uphole Canyon Sand interval was also included in the treatment. Immediately prior to the stimulation, the total depth was 7,246 ft. Evidently 37 of the 57 perforations in the previously treated interval had been covered with sand since January 1996.

b. Candidate Well #2 - Hatton 7C-7 (36960)

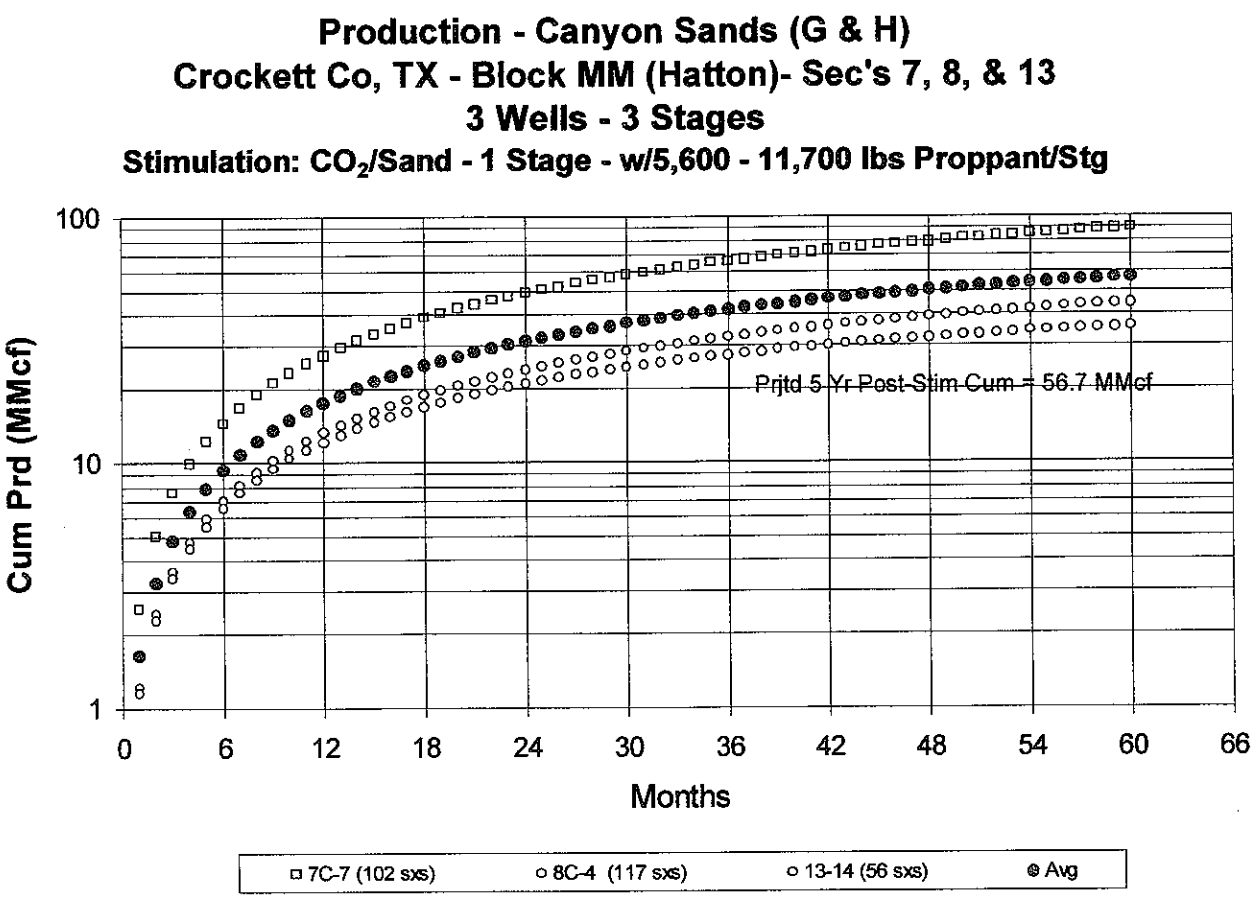


c. Candidate Well #3 - Hatton 8C-14 (36991)



d. Summary – Candidate Wells

The five year cumulative production from the three Candidate Wells ranged between 35.6 and 89.9 MMcf and averaged 56.7 MMcf.



e. Production Comparisons – Summary

The production from the three Candidate Wells was considerably less than that from the Control Wells. The projected five year cumulative production ranged from 35.6 to 89.9 MMcf and averaged 56.7 MMcf. That from the ten Control wells ranged from 62.8 to 434.2 MMcf and averaged 200.3 MMcf or 3.5 times that from the wells stimulated with the liquid CO_2/sand process.

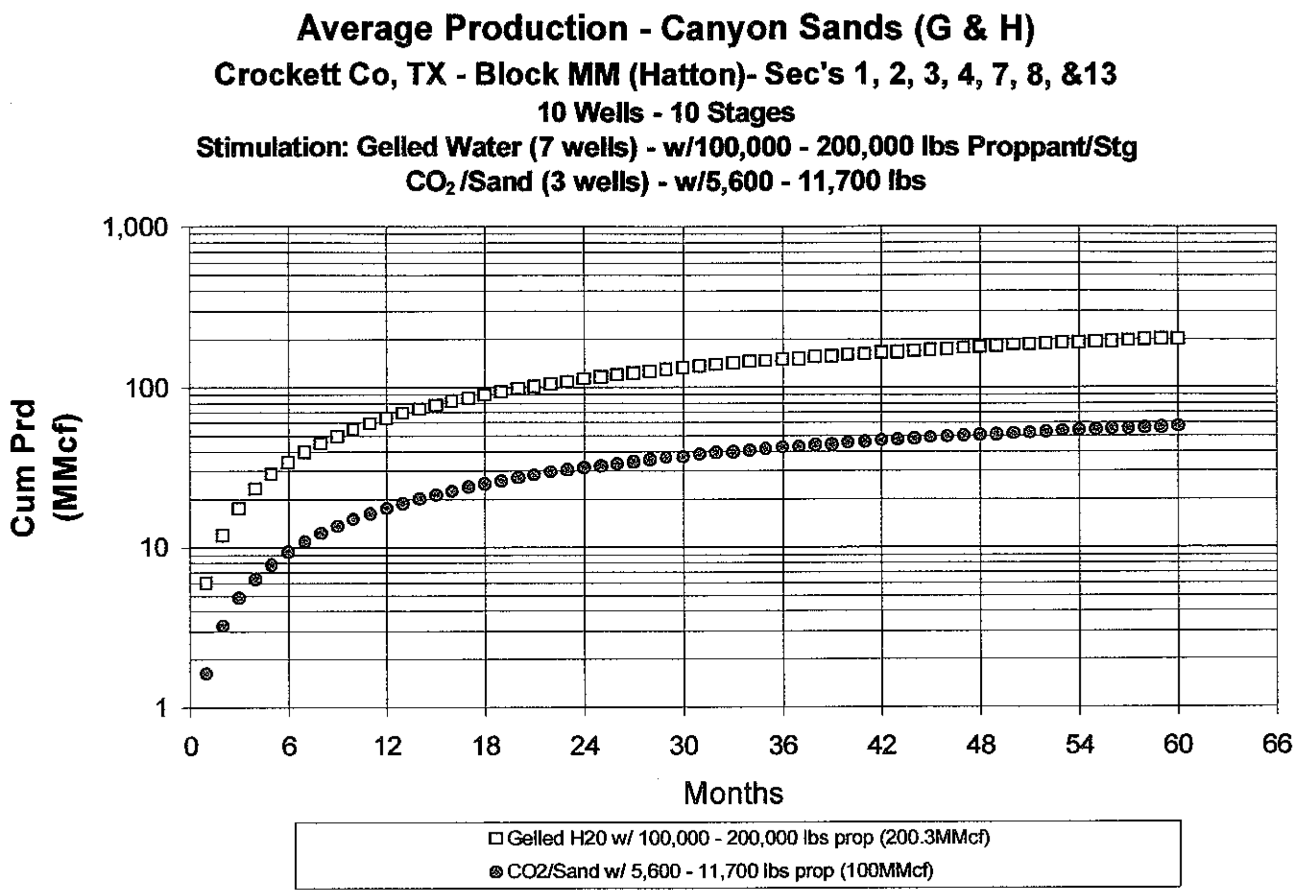
Well	Pmt # 42-105-	5 Yr Prod Proj	5 Yr Prod Actual	Prod Mo	Stim
	Xxxx	(MMcf)	(MMcf)		Type, Sxs, Bbls
Hatton 03-13	32174	434.2	449.6		
Hoover 04-07	34267	332.5	255.7		
Anderson 01-14	32307	292.5	173.0	40	
Hatton 01-14	32124	187.0	199.4		
Hatton 02-08	32004	163.1	166.9		
Hatton 04-08	32260	161.3	150.1		
Hatton 03-14	32182	146.5	160.0		
Hatton 01-08	32003	131.4	109.7		
Hatton 02-13	32165	91.6	89.9		
Hatton 7C-7	36960	89.9	79.1	46	CO_2 102, 640
Hatton 01-13	32143	62.8	65.3		
Hatton 8C-4	36991	44.6	44.3	45	CO_2 117, 659
Hatton 13-14	36848	35.6	23.8	45	CO_2 56, 466

The poor responses from the wells stimulated with the CO_2/sand process are unquestionably related to a number of factors regarding the formation characteristics of permeability, and pressure, but to a larger extent to the reduced proppant volumes placed by the liquid-free treatments.

A UPR Inter-Office Correspondence (09/18/96) related:

"... A final review of the CO_2 + sand (no water) fracture treatments indicated that these treatments under perform water-based fluids. The three wells stimulated with CO_2 fracture treatments produced an average of 12.7 MMCF in six months, compared to 17.2 MMCF for offset wells (about 35% more that the CO_2 wells). EURs for the CO_2 wells averaged 111 MMCF compared to 233 MMCF for offset wells. Initial production from the wells stimulated using CO_2 was encouraging (115 MCFD vs. 123 MCFD), but production declined rapidly. Therefore, it is recommended that all CO_2 wells be re-fractured and/or re-completed into upper Canyon zones and commingled."

"The average EUR for wells drilled in 1994-96 is 306 MMCF (excluding CO_2 wells) compared to 593 MMCF for older wells. The decline in EUR is primarily due to offset well drainage. The results from 1-stage and 2-stage fracture treatments showed almost identical results (EUR's of 305 vs. 307 MMCF). This may be due to poor zone selection (one stage isn't contributing), cross-flow, increased liquid loading, etc. Additional work is planned to better define the effects of staging...."



6. Conclusions - Test Area #2

a. Liquid CO_2/sand stimulations were somewhat successfully pumped in the Canyon Sands. Although it had not been conclusively established that they could be successfully pumped they were, but at considerably reduced proppant volumes than the design.

b. The production from the three Candidate Wells was considerably less than that from the Control Wells.

The projected five year cumulative production averaged 56.7 MMcf while that from the ten Control wells averaged 200.3 MMcf or 3.5 times that from the wells stimulated with the liquid CO_2/sand process.

c. These poor responses from the wells stimulated with the CO_2/sand process are unquestionably related to a number of factors regarding the formation characteristics of permeability, and pressure, but to a larger extent to the reduced proppant volumes placed by the liquid-free treatments

d. The proppant volumes placed were much less than the design and ranged from 5,600 to 11,700 pounds or approximately twelve percent of that placed in conventional treatments. The actual volumes placed in zone were:

	Pumped	Removed from well	Net in zone
Well	(K lbs)	(K lbs)	(K lbs)
Hatton 13-14	1.39	8.3	5.6
Hoover 7C-7	11.2	1.0	10.2
Hatton 8C-4	14.0	2.3	11.7

And, the ability to place the design quantities was obviously limited by

(1) The reduced pump rate of 40 barrels per minute, which was driven by a maximum well head pressure of 6,500 psi.

(2) High leak off rates into the formation.

After the tubing was installed, the production levels would not support the additional expense of CO_2/Sand stimulations, even if the well with poor geology, 13-14, is eliminated.

e. The costs for the CO_2/sand stimulations (6 wells - 9 stages) was $407,462 or $45,274 per stage. Cost advantages resulted from a major reduction in pumping costs through the utilization of a locally available service company, Halliburton Energy Services (HES). The original bid was much greater and also required a significant mobilization charge. To a lesser extent, a cost savings for CO_2 of $7,380 was realized by utilizing another supplier.

f. In retrospect the inability of Halliburton to provide the design pump rate primarily because of the significant CO_2 leaks and the utilization of small diameter plungers compromised the ability to place proppant.

Significant equipment problems with CO_2 leakage around the piston rods was experienced. There were twelve Halliburton pumpers and the leakage became so severe that the pumpers were obscured from the blender operators position. They were shut down and partially remediated.

XVI. COSTS

A. Projected

The estimated stimulation costs were significantly greater than those budgeted $45,274 vs. 67,055. The increases are due primarily to:

1. Higher horsepower requirements

   The subject wells were projected to require greater pumping horsepower, 6,643-7,200 rather than the 4,000 utilized in the budget which adds an additional $10,414-13,000 per stage.

2. Full horsepower charge for both stages.

   Canadian Fracmaster was unwilling to provide the pumping for the second stage except for full single stage cost which was projected to add an additional $33,840 to the second stage treatment.

3. Mobilization costs - Universal Well Services was unwilling to involve any third party pumping service companies. They were willing to transport their pumping equipment from the eastern U.S. per their schedule, or to utilize Canadian Fracmaster's pumping equipment. A complete frac spread from Universal would only be made available in the spring, during their slow period.

   They were willing to involve Canadian Fracmaster with equipment mobilized from Red Deer, Alberta. Universal was willing to provide two (2) pump trucks, the blender, and a frac van to be used in conjunction with Canadian Fracmaster's hardware pump trucks (1,800 HHP each).

Under both scenarios the mobilization costs were expensive and only become reasonable if they were amortized over a number of stimulation events.

The mobilization costs for the subject wells were estimated at $24,000 which included mobilization only from Grand Junction, Colorado, providing that the treatments could be scheduled to complement Canadian Fracmaster's scheduled trip to Grand Junction. Otherwise, an additional $35,640 would be required.

The cost of CO_2/Sand stimulations was estimated to be $44,000 greater than conventional treatments.

Wells	Stages	Stim Cost ($)	Contingencies ($)	Est DOE Cost ($)
6	9	191,164	15,000	= $206,164

B. Actual

The Halliburton invoices were reviewed and approved. The final approval costs were:

	UPRC to Pay	UPRC Net	PCS Net
Halliburton	$158,070.67	$ 80,208.05	$ 77,862.62
Flo CO_2	97,380.00	48,690.00	48,690.00
Universal	132,350.05	66,175.03	66,175.03
Guardian	19,661.53	19,661.53	0.00
Total	$407,462.25	$214,734.61	$192,727.65

C. Projected vs. Actual

The estimated cost for stimulating the wells (6 wells - 9 stages) was reduced from $609,445 to $407,462. The reduction was due primarily to a major reduction in pumping costs which resulted from the utilization of a locally available service company, Halliburton Energy Services (HES). The original bid was much greater and also required a significant mobilization charge. To a lesser extent, a cost savings for CO_2 of $7,380 was realized by utilizing another supplier.

The Department of Energy (DOE) cost-shared portion was 50% of the stimulation costs and the operator, UPRC, was responsible for the remaining 50%.

XVII. CONCLUSIONS – TEST AREAS 1 AND 2

A. With one exception, all nine stages, six on the Montgomery lease and three on the Hatton leases were rate-limited to approximately 40-43 barrels per minute because of the maximum allowable wellhead treating pressures of approximately 6,200 psi. Forty barrels per minute is approaching the minimum injection rates to reliably transport 20/40 size sand proppant.

B. The production from the Candidate Wells was disappointingly low:

1. Test Area #1 Block NG (Montgomery)
The projected five year cumulative production averaged 100.4 MMcf while that from the seven Control wells averaged 745.0 MMcf or 7.4 times that from the wells stimulated with the liquid CO_2/sand process.

2. Test Area #2 Block MM (Hoover)
The projected five year cumulative production averaged 56.7 MMcf while that from the ten Control wells averaged 200.3 MMcf or 3.5 times that from the wells stimulated with the liquid CO_2/sand process.

C. These poor responses from the wells stimulated with the CO_2/sand process are unquestionably related to a number of factors regarding the formation characteristics of permeability, and pressure, <u>but to a larger extent to the reduced proppant volumes placed by the liquid-free treatments</u>

D. The placed proppant volumes with the CO_2/sand process were much lower than the design volumes:

1. Test Area #1 Block NG (Montgomery)

The proppant volumes placed were much less than the design and ranged from 8,100 to 24,200 pounds per stage. If the lowest volume, 8,100 pounds is removed, the five stage range was 10,400 to 24,200 and averaged 17,600 pounds or approximately twelve percent of that placed in conventional treatments.

The actual volumes placed in zone were:

Stage 1			
	Pumped	Removed from well	Net in zone
Well	(K lbs)	(K lbs)	(K lbs)
Montgomery 13-18	26.5	2.3	24.2
Montgomery 12-18	25.0	14.6	10.4
Montgomery 14-18	11.5	3.4	8.1

Stage 2			
	Pumped	Removed from well	Net in zone
Well	(K lbs)	(K lbs)	(K lbs)
Montgomery 13-18	26.1	5.3	20.8
Montgomery 12-18	20.7	0.9	19.8
Montgomery 14-18	13.7	0.8	12.9

The treatments are summarized

		Sand (sacks)		Max Tr Press	Avg Rate	Sand Conc (lb/gal)	
Well	Stg	Pumped	In-Zone	Psi	BPM	Max	Avg
M#13	1	265	242	6,200	47.0	3.0	2.0
M#13	2	261	208	5,796	40.0	3.0	1.5
M#12	1	250	104	6,500	40.0	2.0	1.4
M#12	2	207	198	6,100	43.0	2.0	1.6
M#14	1	115	81	5,590	39.6	2.0	0.9
M#14	2	137	129	5,600	43.0	2.0	1.2

2. Test Area #2 Block MM (Hoover)

The proppant volumes placed were much less than the design and ranged from 5,600 to 11,700 pounds or approximately twelve percent of that placed in conventional treatments. The actual volumes placed in zone were:

	Pumped	Removed from well	Net in zone
Well	(K lbs)	(K lbs)	(K lbs)
Hatton 13-14	1.39	8.3	5.6
Hoover 7C-7	11.2	1.0	10.2
Hatton 8C-4	14.0	2.3	11.7

And, the ability to place the design quantities was obviously limited by

(1) The reduced pump rate of 40 barrels per minute, which was driven by a maximum well head pressure of 6,500 psi.

(2) High leak off rates into the formation.

The treatments are summarized

	Sand (sacks)		Max Tr Press	Avg Rate	Sand Conc (lb/gal)	
Well	Pumped	In-Zone	Psi	BPM	Max	Avg
Hatton 13-14	139	56	7,400	39.0	2.0	1.1
Hoover 7C-7	112	102	6,050	39.5	1.0	0.8
Hatton 8C-4	140	117	6,250	40.0	2.0	1.0

E. The costs for the CO_2/sand stimulations (6 wells - 9 stages) was $407,462 or $45,274 per stage. Cost advantages resulted from a major reduction in pumping costs through the utilization of a locally available service company, Halliburton Energy Services (HES). The original bid was much greater and also required a significant mobilization charge. To a lesser extent, a cost savings for CO_2 of $7,380 was realized by utilizing another supplier.

PETROLEUM CONSULTING SERVICES
P O BOX 35833
CANTON, OHIO 44735-5833
(216) 499-3823

COST DETAIL 12/19/95

WELL:	M12	M13	M14	7C-7	8C-4	13-14	
STAGE:	1	1	1	1	1	1	
DATE:	12/12/95	12/12/95	12/13/95	12/15/95	12/15/95	12/15/95	
HES							
PUMPING:	13000.00	13000.00	26000.00	8666.66	8666.66	8666.66	
SAND:	3182.50	2345.43	1782.20	1247.54	3946.30	1845.85	
DRAYAGE:	653.12	110.00	365.75	653.12		653.12	
WASH:	30.00	280.25					
MISC:		3682.20	110.00	1793.50	2637.14	1827.50	
TOT	16865.62	19417.88	28257.95	12360.82	15250.10	12993.13	
STAGE:	2	2	2	N/A	N/A	N/A	
DATE:	12/14/95	12/14/95	12/14/95				
HES							
PUMPING:	8666.66	8666.66	8666.66				
SAND:	2711.49	4188.17	1807.66				
DRAYAGE:	556.46	859.51	867.34				
WASH:		98.75					
MISC:		11222.25	3362.50				
TOT	11934.61	25035.34	14704.16				
N2							
STAGE:	1 & 2	1 & 2	1 & 2	1	1	1	
N2:	3248.00	4774.40	2048.00	1664.00	240.00	1552.00	
PMPNG:	285.00	285.00	985.00	985.00	28.50	985.00	
ADD'L PMPNG:	1600.00	800.00					
MISC:	255.00	1240.00	285.50	283.50	455.00	397.50	
TOT	5388.00	7099.40	3318.50	2932.50	723.50	2934.50	
TOT HES	34188.23	51552.62	46280.61	15293.32	15973.60	15927.63	179218.01

FLOCO2							
STAGE 1							
CO2:	9490.00	10335.00	12155.00	9685.00	10725.00	7735.00	
PRTBLES:	200.00	200.00	200.00	200.00	200.00	200.00	
MISC:	545.00	582.50	545.00	80.00	80.00	100.00	
STAGE 2							
CO2:	10270.00	10780.00	10780.00				
PRTBLES:	200.00	200.00	200.00				
MISC:	545.00	582.50	545.00				
TOT	21250.00	22690.00	24435.00	9985.00	11005.00	8035.00	97380.00
UWS							
STAGE 1							
BLENDER:	6000	6000	6000	6000	6000	6000	
LISC FEE:	5000	5000	5000	5000	5000	5000	
TUBE TRLR:	5500	5500	5500	5500	5500	5500	
MI&P DIEM:	2984	4583	2984			800	
STAGE 2							
BLENDER:	0	0	0				
LISC FEE:	5000	5000	5000				
TUBE TRLR:	2500	2500	2500				
TOT	26984.00	28583.00	26984.00	16500.00	16500.00	17300.00	132851.00
TOTALS							409447.01
HES							
PUMPING:	21666.66	21666.66	34668.66	8666.66	8666.66	8666.66	
SAND:	5893.99	6533.60	3589.86	1247.54	3846.30	1845.85	
DRAYAGE:	1209.58	969.51	1233.09	653.12	0.00	653.12	
WASH:	30.00	379.00	0.00	0.00	0.00	0.00	
MISC:	0.00	14904.45	3472.50	1793.50	2637.14	1827.50	
N2:	3248.00	4774.40	2048.00	1684.00	240.00	1552.00	
PMPNG:	285.00	285.00	985.00	985.00	28.50	985.00	
ADD'L PMPNG:	1600.00	800.00	0.00	0.00	0.00	0.00	
MISC:	255.00	1240.00	285.50	283.50	455.00	397.50	
	34188.23	51552.62	46280.61	15293.32	15973.60	15927.63	
FLOCO2							
CO2:	19760.00	21125.00	22945.00	9685.00	10725.00	7735.00	
PRTBLES:	400.00	400.00	400.00	200.00	200.00	200.00	
MISC:	1090.00	1165.00	1090.00	80.00	80.00	100.00	
	21250.00	22690.00	24435.00	9965.00	11005.00	8035.00	
UWS	26984.00	28583.00	26984.00	16500.00	16500.00	17300.00	
TOT	82422.23	102825.62	97699.61	41758.32	43478.60	41262.63	409447.01

F. In retrospect the inability of Halliburton to provide the design pump rate primarily because of the significant CO_2 leaks and the utilization of small diameter plungers compromised the ability to place proppant.

Significant equipment problems with CO_2 leakage around the piston rods was experienced. There were twelve Halliburton pumpers and the leakage became so severe that they were not visible from the blender operators position. They were shut down and partially remediated.

G. Summarizing, the conclusion is that fracture lengths longer than those which can be generated with CO_2/Sand stimulations are required in this area. It is too "tight".

H. The production from only one well, Montgomery #14, exceeded the economic hurdle rate, the others are significantly below the economic rate, the conclusion is that larger fracture lengths than can be generated with CO_2/Sand stimulations are required in this area. It is too "tight".

This concludes the project effort for the demonstrations of the liquid CO_2/sand stimulations in 6 wells (9 stages) operated by Union Pacific in The Canyon Sands in the Ozona field (Crocket Co, Texas). They are now owned and operated by Anadarko Petroleum. The conclusions indicate that because of the inability to place adequate proppant volumes that the results are an economic failure, and that there is little likelihood of practically placing increased proppant volumes.

FIELD TESTING & OPTIMIZATION OF CO_2/SAND FRACTURING TECHNOLOGY
Group #2 – San Juan Co, NM – January 1996 – Three Wells – Single Stage Treatments – Amoco

Final Report

By
RAYMOND L. MAZZA

Period of Performance
October 1, 1994 – November 30, 2004

Work Performed Under Contract No.: Contract #DE-AC21-94MC31199
"Field Testing & Optimization of CO_2/Sand Fracturing Technology"

For:
U. S. Department of Energy
National Energy Technology Laboratory
Morgantown, West Virginia

By
Petroleum Consulting Services
Canton, Ohio

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DISCLAIMER

ABSTRACT

The demonstration of a 100% liquid free CO_2/sand stimulation process was executed on three wells (three stages) in the Fruitland Coal in San Juan Co, New Mexico. The process is unique in that because CO_2 is the only fluid which enters the formation, it requires a specialized closed system, pressurized blender to mix up to 45,000 pounds of proppant with the CO_2. The CO_2 vaporizes at reservoir conditions and leaves a liquid-free proppant pack. The reduced proppant volume (45,000 vs. 250,000 pounds) from that used with the conventional water-based stimulations was recognized; however, the reduction in formation damage from retained liquids could have resulted in a net benefit.

The three Candidate Wells were selected and stimulated with CO_2/Sand in January 1996. The wells had limited sand volumes placed and have not produced at economic rates. The production from all three has been generally lower than that from conventionally stimulated wells. The limited placement of sand is suspected of being a result of the very large number of perforations, approximately 300 which reduced the transport velocity; and additional testing with significantly fewer perforations is recommended.

I. ABSTRACT

The demonstration of a 100% liquid free CO_2/sand stimulation process was executed on three wells (three stages) in the Fruitland Coal in San Juan Co, New Mexico. The process is unique in that because CO_2 is the only fluid which enters the formation, it requires a specialized closed system, pressurized blender to mix up to 45,000 pounds of proppant with the CO_2. The CO_2 vaporizes at reservoir conditions and leaves a liquid-free proppant pack. The reduced proppant volume (45,000 vs. 250,000 pounds) from that used with the conventional water-based stimulations was recognized; however, the reduction in formation damage from retained liquids could have resulted in a net benefit.

The three Candidate Wells were selected and stimulated with CO_2/Sand in January 1996. The wells had limited sand volumes placed and have not produced at economic rates. The production from all three has been generally lower than that from conventionally stimulated wells. The limited placement of sand is suspected of being a result of the very large number of perforations, approximately 300 which reduced the transport velocity; and additional testing with significantly fewer perforations is recommended.

II. INTRODUCTION

In 1995 Amoco Production Company (Amoco) - now BP - had an active drilling program in the Fruitland Coals in San Juan County, New Mexico and indicated a strong interest in participating in the DOE's cost shared demonstration project to evaluate the potential of the liquid-free, CO_2/Sand stimulation technology.

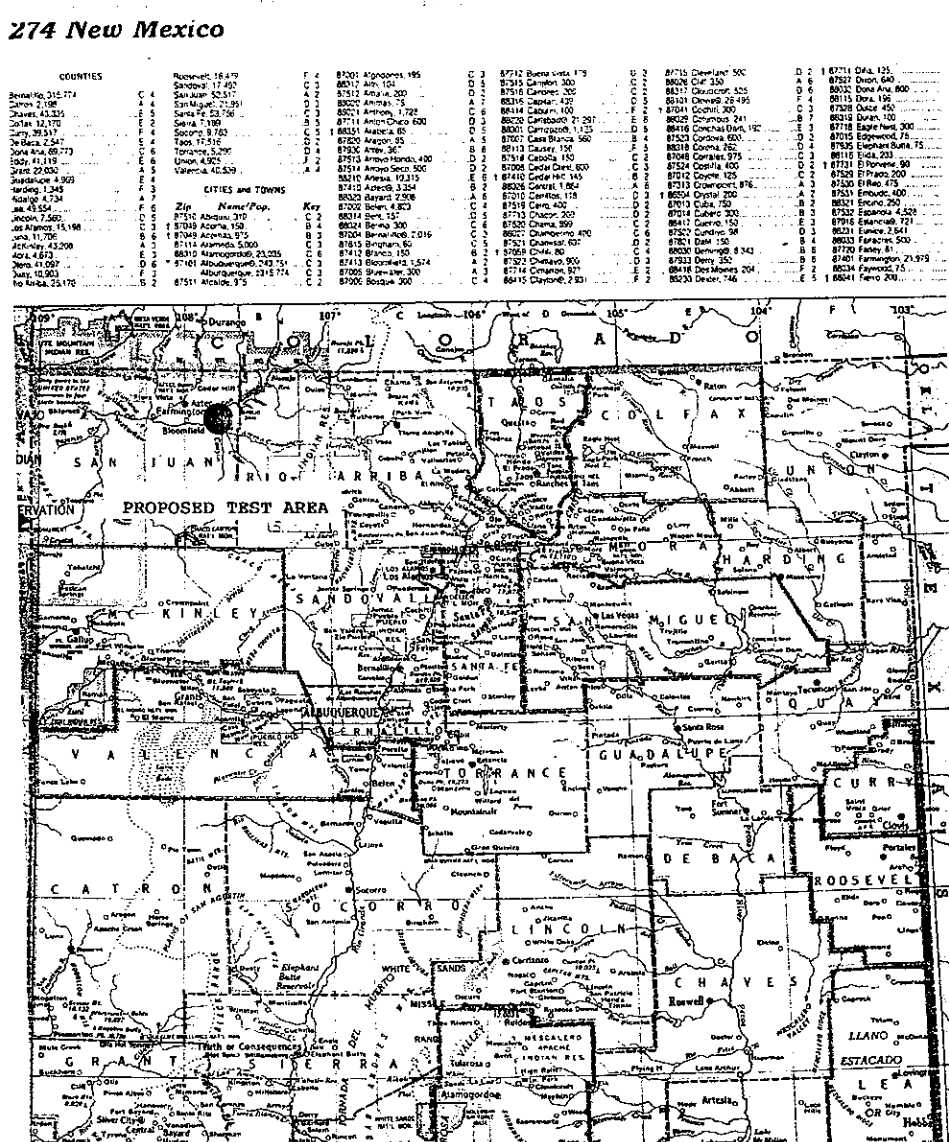
The Candidate Wells were considered to provide a good opportunity to demonstrate the CO_2\Sand stimulation process in a liquid-sensitive reservoir where the capillary retention of stimulation liquids was known to be detrimental to gas production.

If the treatments turned out to be successful, then the marginal nature of this portion of this reservoir (Type III) would become more economically attractive.

III. BACKGROUND

The wells producing from the Fruitland Coals in San Juan County (Figure 1) which are located on the "Fairway" are very prolific gas producers and are designated as Type I. The Candidate Wells which were offered by Amoco were situated southwest of the "Fairway" in an economic "fringe" area where the coals are designated as Type III where the reservoir pressure is lower, the formations are dry, and the clean up time from the conventional nitrogen foam stimulations is longer.

Figure 1



The Type III Fruitland Coals are liquid free, except for some occasional condensate production, which may reside in the Pictured Cliff Sandstone (PC) which is subjacent to the basal coal member. The Fruitland Coal interval in other areas is water productive and produces both gas and formation water in significant volumes. In the area of the Candidate Wells the coals are dry and have lower permeability, and therefore were considered to be good candidates for the liquid free CO_2/Sand stimulation process.

IV. METHODOLOGY

The evaluation of the CO_2/Sand stimulations was affected through the comparison of the five-year cumulative produced gas volumes from the Candidate Wells which were stimulated with CO_2/Sand with that from nearby Control Wells which had been stimulated with other processes. These other stimulation processes included N_2 foam, and gelled water.

The wells with the larger projected five-year cumulative produced gas volumes, after the flush production was removed, were considered to be superior.

A. Mathematical Analog of Production Data

The procedure to remove the flush production volumes utilizes a fit of a mathematic equation of the later time production, and then utilizing that relationship to extrapolate the early production as if the flush production rates had not occurred.

There were some instances where the flush production volumes were minimal which reinforces the benefit of being able to more acutely focus in on the reservoir characteristics through the elimination of this bias. This process can also provide a significant benefit when there is missing production data.

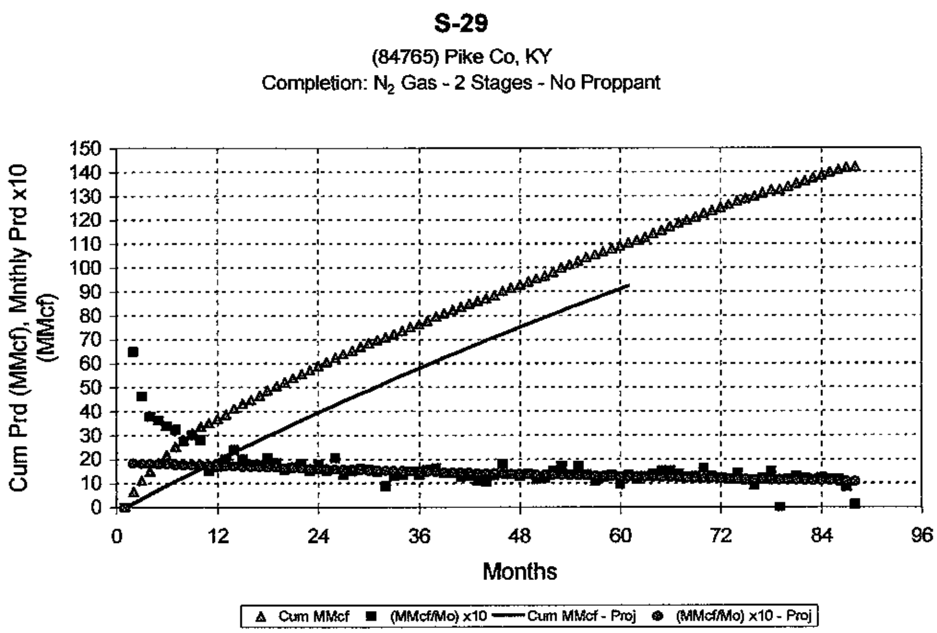
B. Missing Data

This process can also provide a significant benefit where there is missing production data. Also, in instances where there is only a very limited knowledge of the early production histories or where there is co-metered gas production can benefit as well.

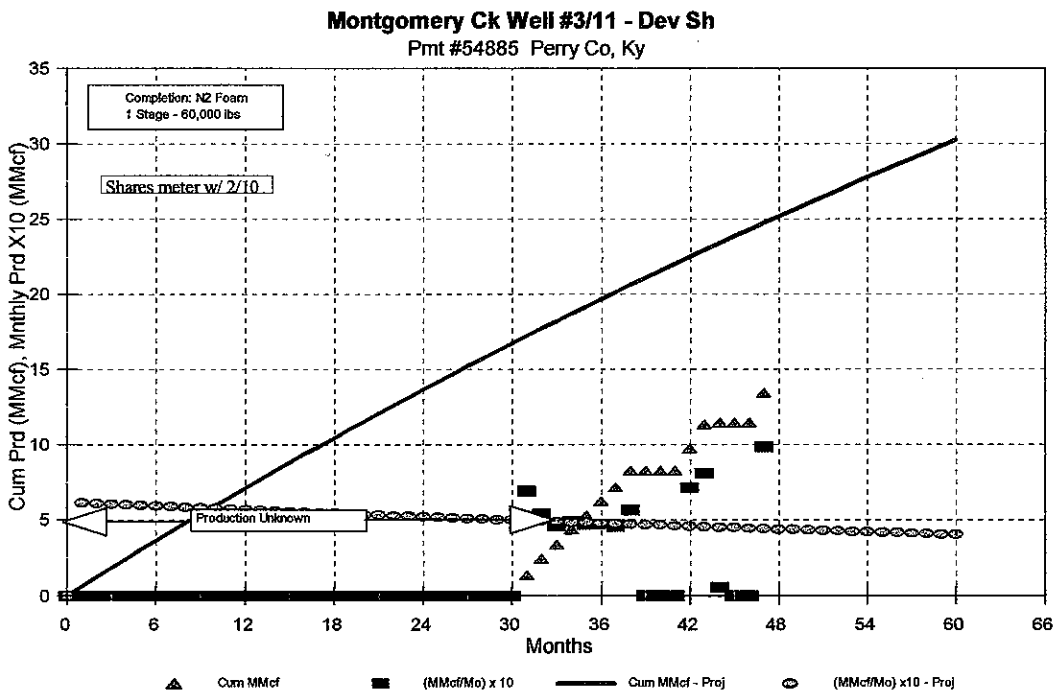
C. Examples

The following examples demonstrate the procedure utilized to remove the gas produced during the flush production period which in this case lasted approximately 13 months.

The actual produced gas volume was 41 MMcf while the projected volume was 23 MMcf or a difference of 18 MMcf. The projected five year cumulative production is 92 MMcf whereas the actual production volume measured was 110 MMcf.



In the second example there was no production data available for the first 29 months, additionally the available data included two shut in periods which are followed by flush production. By utilizing a mathematic fit of the steady state production data a realistic projection of the early time production resulted. The limited data set was then utilized, and the bias resulting from the flush production periods following the shut in periods was removed.

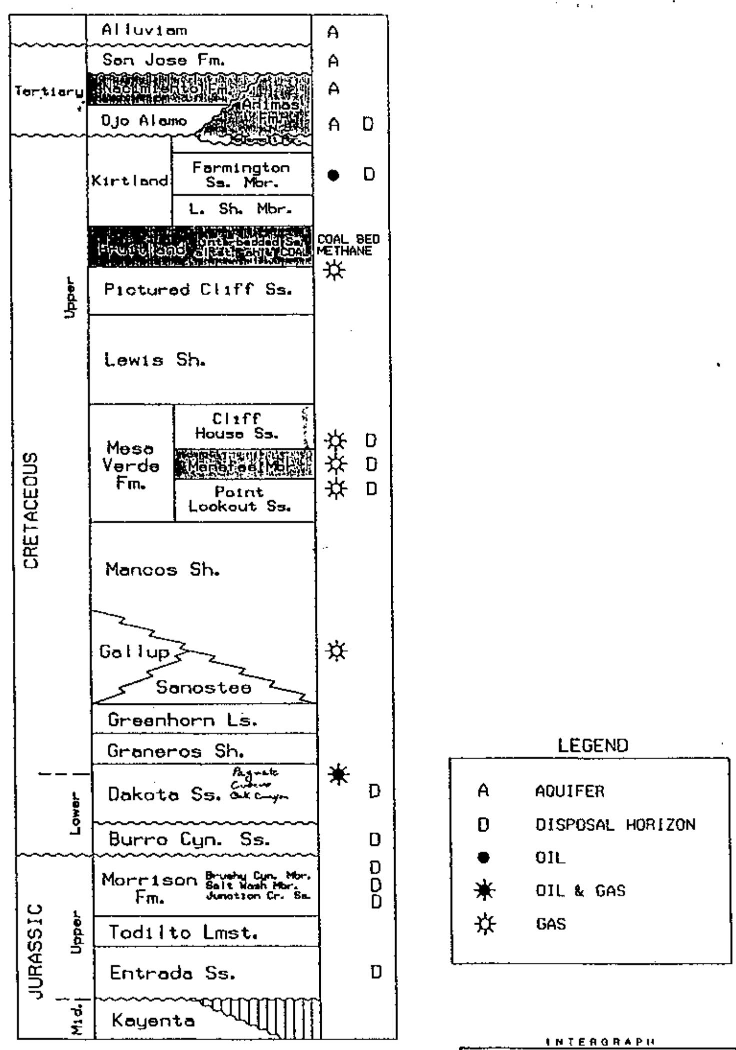


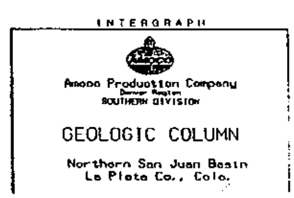
In removing the effects of the flush production volume a more realistic assessment of the response to the different stimulation types resulted. The production plots for each well including the actual and projected values are included in this report.

V. PRODUCING HORIZON

The Fruitland Coals are an Upper Cretaceous sequence of interbedded sandstones, siltstones, shale, and coal which lie a depth of 2,000-2,500 feet in the Test Area (Figure 2). The coals have thicknesses of 36-60 feet, and the basal coal, Cahn, is 45 to 60 feet thick, and is the most productive. It along with other overlying coal members were stimulated. The treated intervals ranged from 120 to 180 feet.

Figure 2





VI. FIELD

The Fruitland Coal wells on the Fairway are in an area designated as Type I and typically produce up to 1,000 Mcf per day along with 10-50 barrels of water (GLR = 20-100 Mcf/bbl) from the reservoir at a pressure of 600-800 psi. To the north of the Fairway in the Type II area the wells produce gas at 0-500 Mcf per day and 10-50 barrels of water (GLR = 25-50 Mcf/bbl).

A. Type III Area

In the Type III area southwest of the Fairway where the Candidate Wells are situated, the production is typically 0-250 Mcf per day and is essentially water free. The wells can produce 1-2 barrels of liquid daily (GLR = 165 Mcf/bbl), sometimes mostly condensate which may originate in the underlying Pictured Cliff Sandstone(PC).

		Reservoir Pressure		Gas prod	Water	GLR
Type	Location	$P_{original}$	P_{now}	Mcfd	Bwpd	Mcf/bbl
I	Fairway (FW)	1000	600-800	>1000	10-50	20-100
II	NE of FW	1000	600-800	0-500	10-20	25-50
III	SW of FW (Target)	500	500	0-250	1-2	125-250

B. Pipeline pressure

The pipeline pressure ranges between 125 and 150 psi which was the pressure at which the Candidate Wells were initially producing. Well head compressors were subsequently installed and the flowing pressure was reduced to approximately 10 psi.

VII. RESERVOIR

A. Reservoir Pressure and Temperature

The reservoir pressure and temperature in the area where the Candidate Wells are situated is approximately 500 psi and 102 degrees Fahrenheit respectively.

	Temp	Total Depth
Well	(°F)	(ft)
Riddle I-1	101	2,277
Florance GCL-1	N/R	2,206
Florance Q-1	105	2,264

VIII. CO_2 CHARACTERISTICS

The accompanying pressure-enthalpy diagram (Figure 3) indicates the projected states of the CO_2 during the pumping, flow back, and producing events. The CO_2 will readily vaporize under these conditions and will require $-286(10)^3$ BTUs per ton.

	Press	Temp		Density	Enthalpy
Pt # Location	(psi)	(°F)	State	(lb/cuft)	BTU/lbm
PUMPING*					
1 Well head	2,200	0	SC	64.94	-3,905
2 Perfs	3,600	20*	SC	64.52	-3,864
NOT PUMPING					
3 Perfs***	1,000	20	SC	62.50	-3,893
4 Formtn***	750	75	SH	10.00	-3,785
5 Formtn	500	103	SH	4.55	-3,746
6 Perfs	26	103	SH	3.33	-3,756
7 Well head	15	75	SH	0.20	-3,750
* Pumping through 4.50 in casing at 40 bbls per min (residence time = 0.85 min)					
** Heat gain through casing at 40 bbls per min = $88(10)^3$ BTU/min (apx 40 BTU/sqft @ LMDT = 73°F)					
*** At the instant that the pumping is terminated					
-3893-(-3750) = -143 BTU/lb = $-286(10)^3$ BTU/ton					

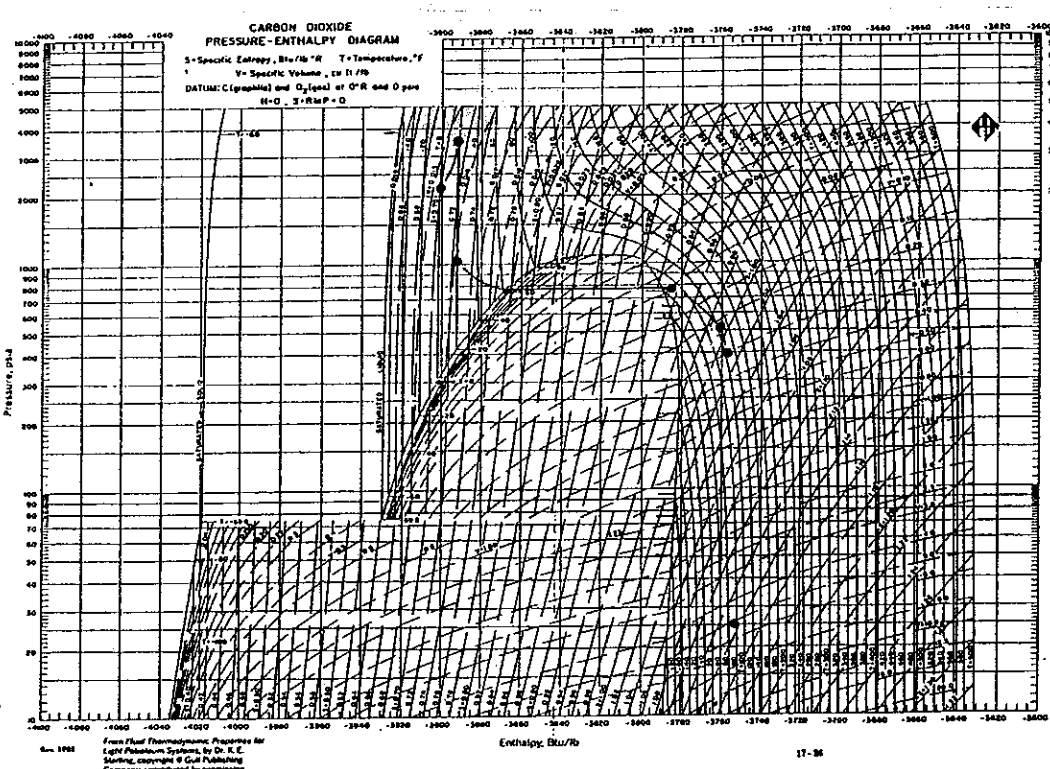


Figure 3

IX. CONVENTIONAL STIMULATION TREATMENTS

In the test area, the wells are typically stimulated with 70-75q nitrogen foam. The sizes are typically 900 barrels and 250,000 pounds of sand.

X. IS THE PROPOSED RESERVOIR LIKELY TO BENEFIT FROM THE CO_2/SAND TECHNOLOGY?

The Fruitland coals in the Type III section have less production potential than Types I and II and are marginally economic with conventional treatments. The potential for improvement was considered to be significant for two primary reasons. The preferential adsorptive capabilities of carbon dioxide over that of methane, and that the benefit of a liquid-free treatment. That is, benefits would result from the liquid free stimulation in a liquid sensitive reservoir, and the CO_2 would displace the methane and enhance the production as well.

A. OPERATOR

1. Interest in CO_2/sand technology?

   Amoco was interested in improving the producing potential of the Fruitland coal in the Type III area, and elected to participate in the demonstration.

2. Adequate test opportunity?

   The proposed Candidate Wells provided an adequate test opportunity to demonstrate and to evaluate the process. The available production data was utilized to generate projections from which a criteria for success was developed.

3. Presently active drilling program?

   Amoco had an active drilling program.

4. Is there a future for successful results? Is the operator likely to continue implementing this technology without DOE cost support?

   Yes, if the technology proved to be economically supportable then Amoco had sufficient acreage and infrastructure to support additional CO_2/sand stimulation activity.

5. Interest in DOE cost-supported participation?

   Amoco indicated a strong interest in the demonstration of the process, provided Candidate Well opportunities with background production information from nearby Control Wells, and executed a Letter of Intent.

6. Share production data for five years?

   Amoco agreed to share the production data for the five year period following the stimulations.

B. Letter of Intent

A Letter of Intent was prepared and executed (Figure 4). It addressed, and Amoco agreed, to the following:

1. To provide legitimate Candidate Well opportunities for three mutually agreed upon wells,
2. To provide acceptable background information on the nearby Control Wells including the drilling, completion, and production specifics,
3. To bear the normal additional expenses of cement bond logging, perforating, bull dozers, and other normally occurring expenses associated with stimulation events,
4. Participating in the demonstration project and the anticipated treatments specifics, and
5. To provide the production information for five years.

Figure 4 (p. 1 of 2)

TGR
A AGREEMENT
Letter ~~of Intent~~
(p. 1 of 2)

Operator: Amoco Production Company (Amoco)

Candidate Wells: San Juan County, New Mexico T28N-R08W

Target Formation: Fruitland Coals

There were six (6) candidate wells proposed in the original submittal (07/02/95). Wells #1 and 5 have been eliminated. One was determined to be on an Indian burial ground and the other would require additional time for partner approvals. The ~~four~~ three TGR remaining candidate wells are:

Well*	Lease	Sec	Quad	Thickness	1st Yr Dly Prod (Mcfd)	Pmt #	Casing	
2	Riddle I1	20	NE	52	150	TBD	4-1/2	
3	Florance GCL1	20	SW	63	140	TBD	4-1/2	
4	Florance Q1	29	NE	60	110	TBD	4-1/2	
~~6~~	~~Story D2~~	~~27~~	~~NE~~	~~48~~	~~75~~	~~TBD~~	~~3-1/2 PB~~	NOT APPROVED TGR

*Designations assigned in the original submittal (07/02/95)

The U. S. Department of Energy will, subject to their approvals, agree to provide cost-shared funding for the stimulation of these candidate wells with Universal Well Service's closed system blender for CO_2\sand treatments, if certain criteria are met. Amoco agrees to bear the remaining expenses.

The project entails demonstrating the process in a controlled environment where sufficient background production information from nearby wells can be used to compare the production results with those of this demonstration project.

The design of the stimulation treatments is to consist of approximately 120 tons of carbon dioxide and 25,000 to 45,000 pounds of sand pumped at injection rates of 35 to 60 barrels per minute, and to consist of up to ~~four (4)~~ three (3) TGR single-stage treatments.

Amoco agrees to operate these wells with wellhead pressures similar to those of the control wells to enable a meaningful comparison of the production from the candidate wells with that of the nearby offset control wells. This will probably necessitate the installation of wellhead compressors similar to those installed on the offset wells. The purpose is to effect a quantitative comparison of the effectiveness of the liquid-free CO_2\sand stimulation with that of nitrogen foam.

The ~~four (4)~~ three (3) TGR candidate wells will be available for stimulation treatments by the second week of January, 1996.

The wells will be turned in line shortly after treatment, and the production will be forwarded to PCS on a monthly basis to enable an evaluation of the CO_2 treatments to be made. DOE is requesting monthly production data on these wells for a minimum of five (5) years following turn-in, including monthly copies of the meter run readings and third party integration statements. They are to be forwarded monthly to Petroleum Consulting Services.

Figure 4 (p. 2 of 2)

~~Letter of Intent~~ AGREEMENT
(p. 2 of 2)

Sand, if any, will be removed from the wellbore at operator's expense, immediately following the stimulation.

The DOE requires the following:

1. Executed Letter of intent — This document
2. A map of the candidate well and nearby offsetting wells - Satisfied
3. Electric logs — HGR ~~Control~~ and candidate wells
4. Cumulative production data — HGR ~~Control~~ and candidate wells
5. Monthly pipeline pressure data — ~~Control~~ and candidate wells
6. Stimulation records tabular and strip charts — ~~Control~~ and candidate wells
7. Well completion reports — ~~Control and~~ candidate wells

* As we do not operate the control wells we can only agree to assist in obtaining this information. HGR

The DOE, subject to their approval, will, through the contractor, Petroleum Consulting Services, pay for one-half (1/2) of the costs of the stimulations, including the service company charges for product (CO_2, sand), services, and mobilization. This is to be accomplished by an invoice from Amoco to PCS for one-half (1/2) of the total stimulation costs which includes all discounts.

Amoco hereby indicates an intention to enter into a 50/50 cost-shared participation of the stimulation expenses for these candidate wells, subject to DOE approvals.

Amoco agrees to bear the remaining expenses of these treatments and any remaining activities, i.e., those expenses normally associated with these treatments: cement bond log, perforating, dozers, service rigs, etc.

If these conditions are satisfactory, please acknowledge by signing below, and returning this document to:

Petroleum Consulting Services
P. O. Box 35833
Canton, Ohio 44735
(216) 499-3823 (216) 499-2280 (fax)

Date: ____________________

Signed: H. G. Rowe

~~Company Officer~~

Title: ATTORNEY - IN - FACT

Witness: ____________________

XI. NEPA COMPLIANCES

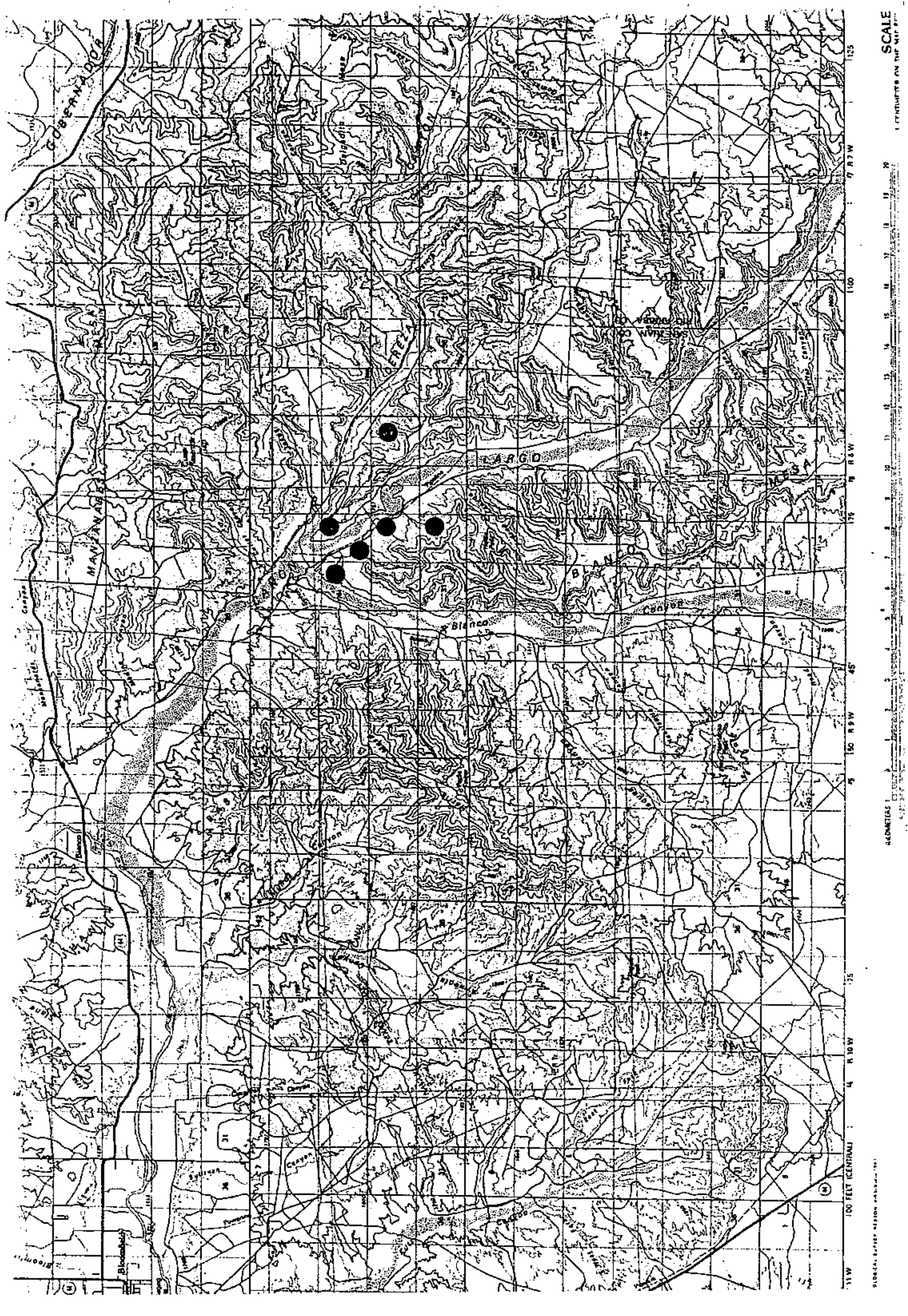
A NEPA questionnaire was prepared for the Candidate Wells. Conversations were held with Amoco's environmental compliance personnel and the specifics of land use, air quality, water resources/water quality, solid waste and hazardous materials, impact on vegetation and animals, aesthetics, historical/cultural resources, transportation, energy requirements, environmental restoration and/or waste management, and worker health and safety were identified and responded to.

Subsequently, the NEPA approval was granted.

XII. TEST AREA

The test area is situated in San Juan Co, New Mexico in Township 28N, Range 8W which is southeast of the town of Blanco along Canyon Largo (Figure 5). It initially consisted of six Control Wells and the six potential Candidate Wells.

Figure 5

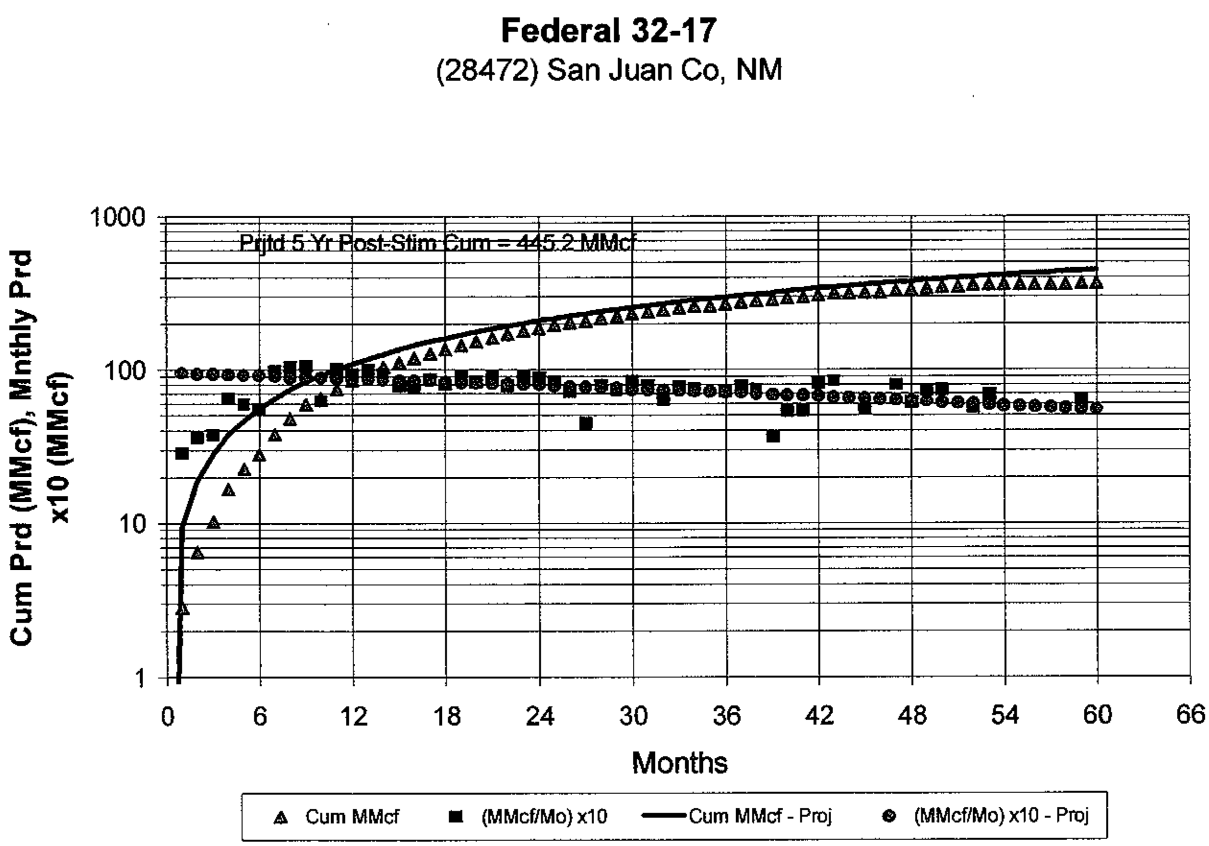

LARGO
BLANCO
Blanco
GOBERNADOR
MANZANARES
SCALE
R 8 W
R 10 W
R 9 W

A. Control Wells – 6 Wells

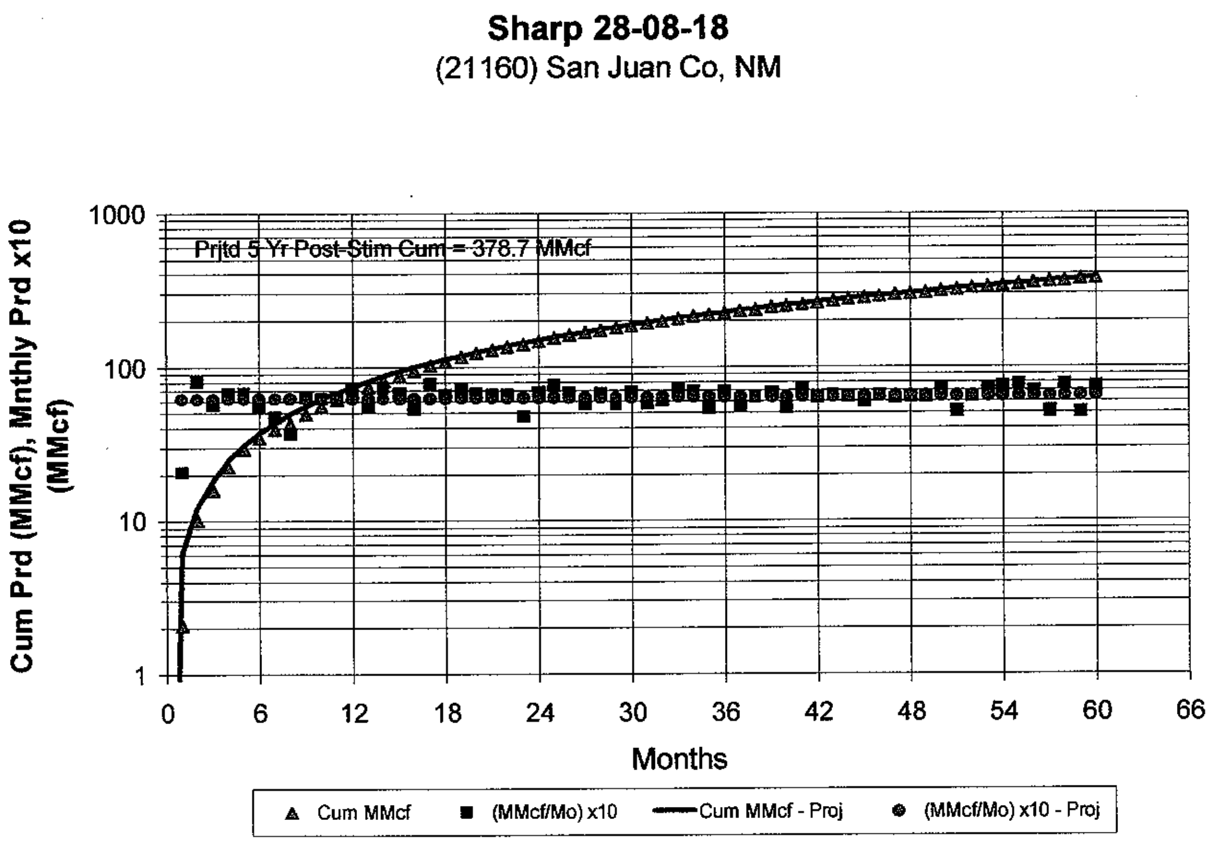
1. Production Review and Projections

The production was plotted and the five year production projection exclusive of flush production and non-productive intervals was generated as described under the preceding METHODOLGY section.

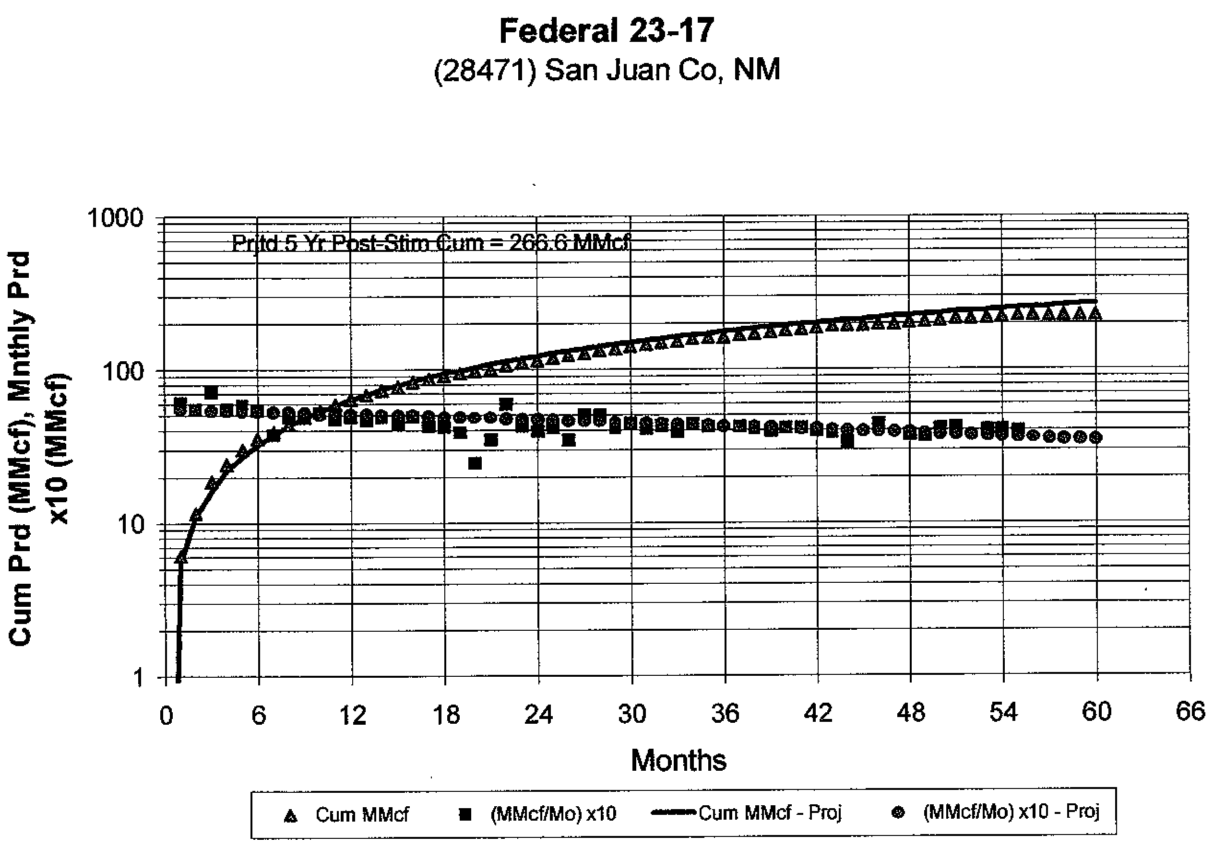
a. Control Well # 1 – Federal 32-17 (28472) – Projected 5 Yr Prod 445.2 MMcf



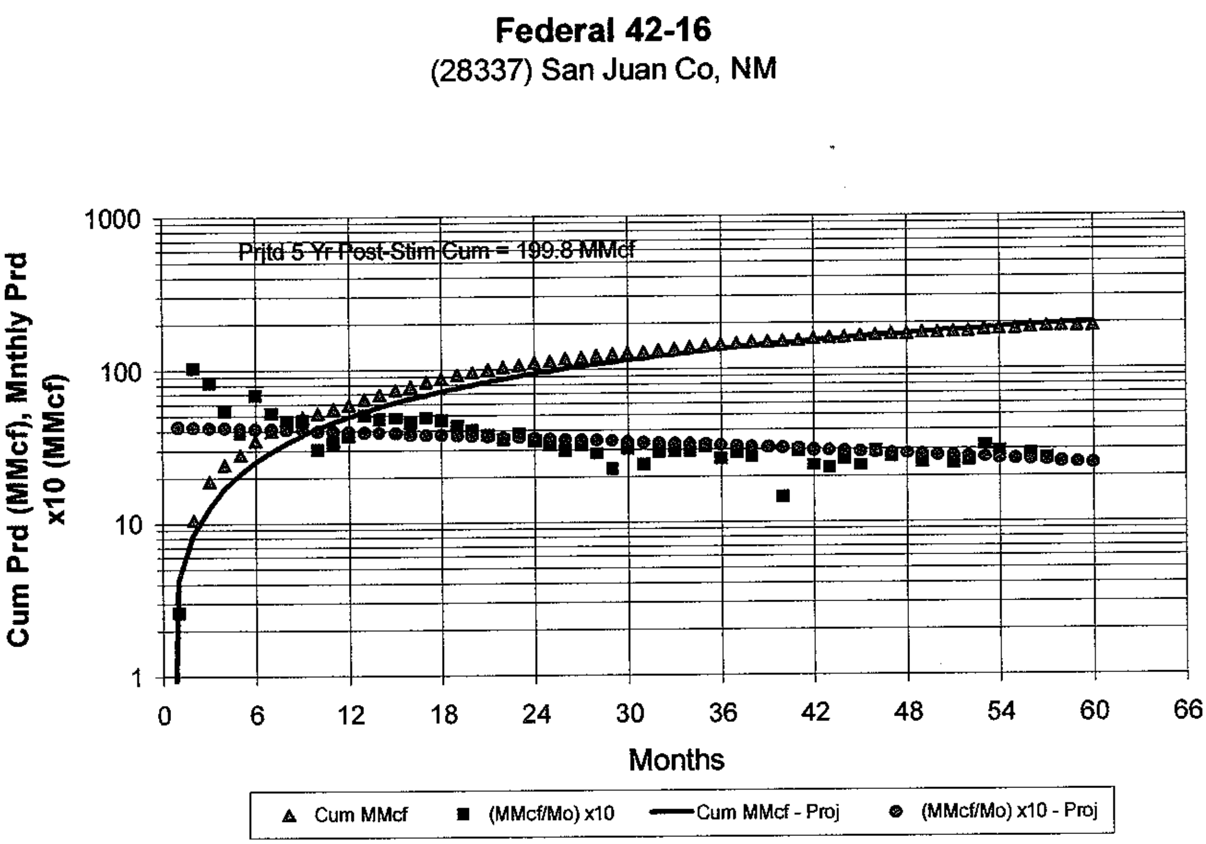
b. Control Well # 2 - Sharp (21160) – Projected 5 Yr Prod 378.7 MMcf



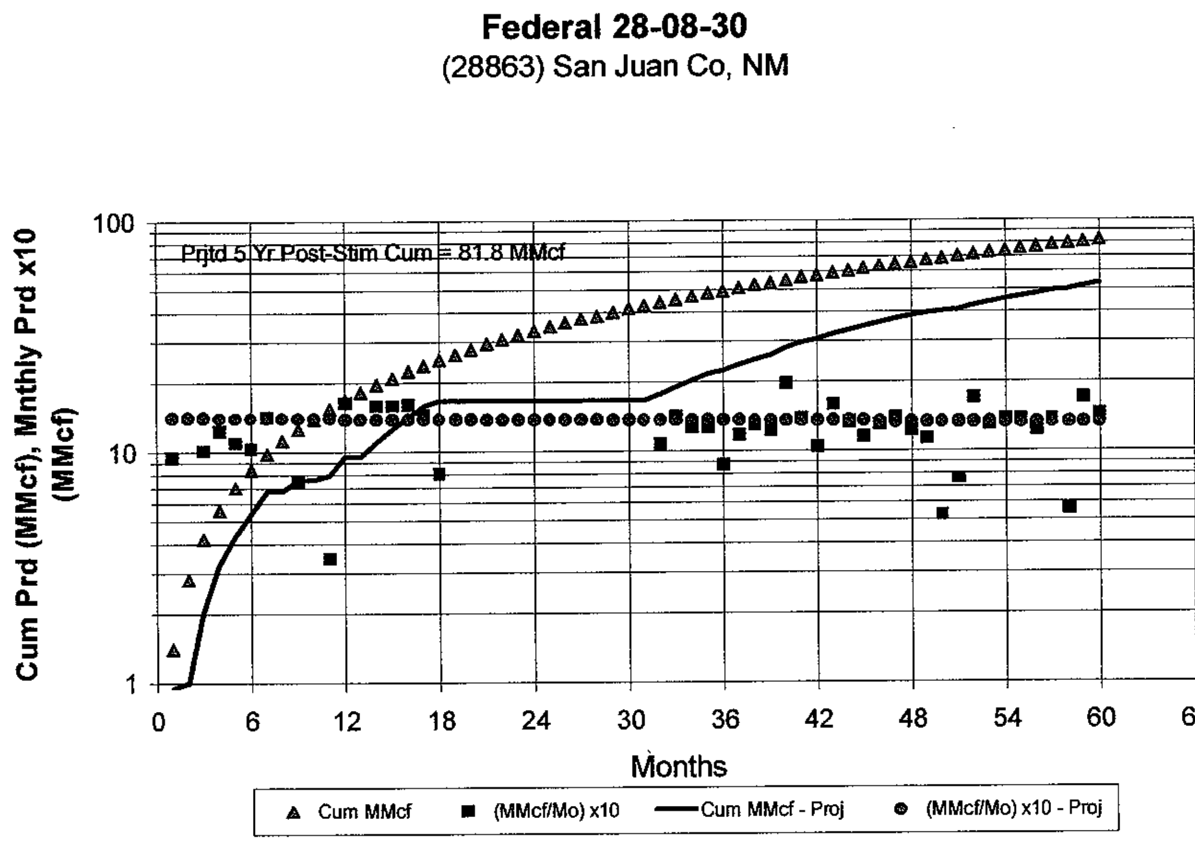
c. Control Well # 3 - Federal 23-17 (28471) – Projected 5 Yr Prod 266.6 MMcf



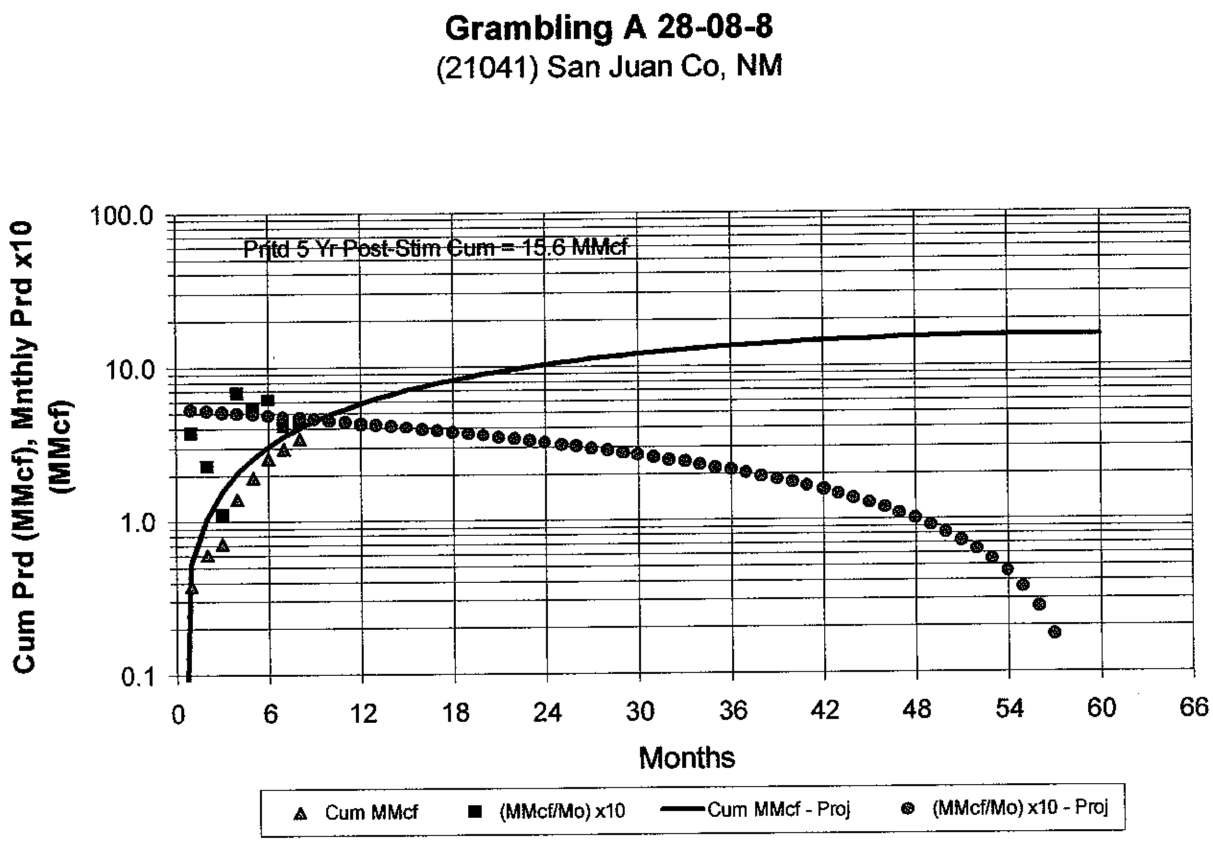
d. Control Well # 4 – Federal 42-16 (28337) – Projected 5 Yr Prod 199.8 MMcf



e. Control Well # 5 – Federal 28-08-30 (28863) – Projected 5 Yr Prod 81.8 MMcf

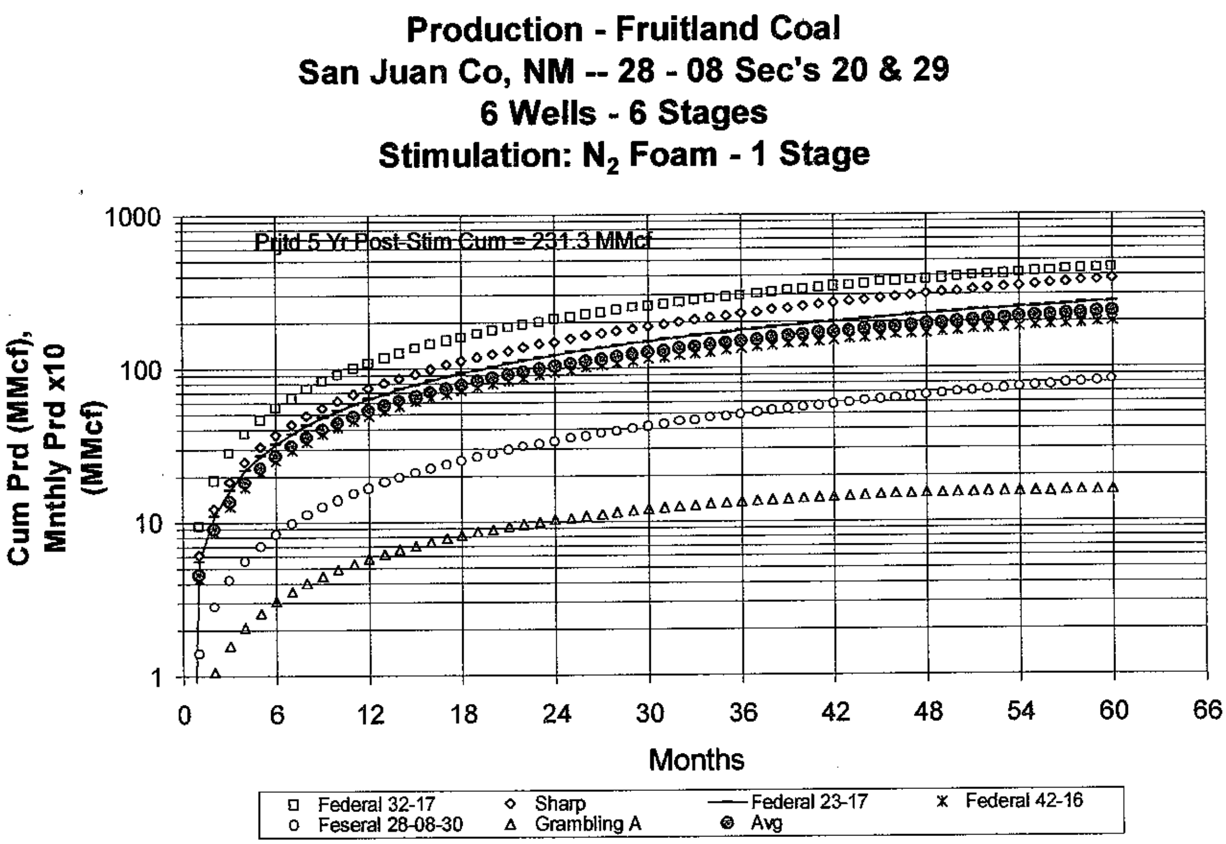


f. Control Well # 6 – Grambling A (21041) – Projected 5 Yr Prod 15.6 MMcf



2. Summary – Control Wells

The five year cumulative production from the six Control Wells ranged between 15.6 and 445.2 MMcf and averaged 231.3 MMcf.



B. Candidate Wells – 3 Wells

Initially there were six proposed Candidate Wells, all located in T28N-R8W. The projected thickness of the basal section of Fruitland Coal (Cahn seam) and first year production are:

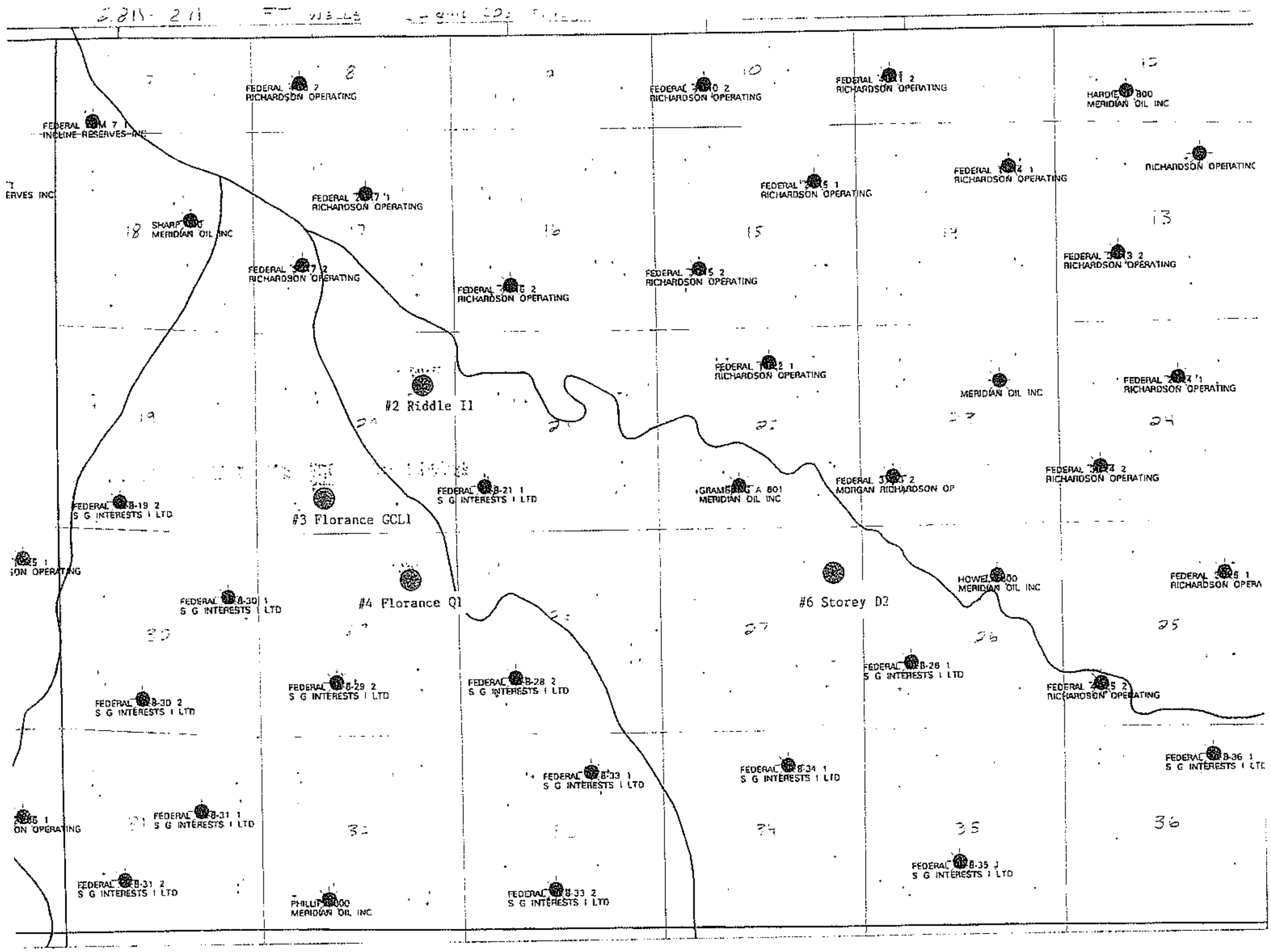
Well #	Sec	Quad	1st Yr Mcfd	Thickness (ft)
1	19	NE	225	55
2	20	NE	150	52
3	20	SW	140	63
4	29	NE	175	60
5	32	NE	100	47
6	27	NE	75	48

Wells #1 and 5 were eliminated. One was determined to be on an Indian burial ground and the other would require additional time for partner approvals. The four remaining Candidate Wells were:

					1st Yr Dly		
Well*	Lease	Sec	Quad	Thickness	Prod (Mcfd)	Pmt #	Casing
2	Riddle I1	20	NE	52	150	29328	4-1/2
3	Florance GCL1	20	SW	63	140	29336	4-1/2
4	Florance Q1	29	NE	60	110	29345	4-1/2
6	Storey D2	27	NE	48	75	TBD	3-1/2 PB
*Designations assigned in the original submittal (07/02/95)							

Figure 6 identifies the position of these wells (green circles) with respect to other Fruitland Coal wells, designated by the smaller circles (red). Additionally, there are other non-Fruitland Coal producers designated by small plus (+) symbols. These wells produce from either the Pictured Cliff Sandstone, the Mesa Verde, or in some instances, the Dakota Sandstone.

Figure 6


#2 Riddle II
#3 Florance GCL1
#4 Florance Q1
#6 Storey D2
RICHARDSON OPERATING
MERIDIAN OIL INC
S G INTERESTS I LTD

The well with the 3.50 inch casing, Storey D2, was a Dakota plug back (TD = 7,105 ft) and had the least potential for gas production of any of the six (6) originally proposed wells. With conventional treatments, it was estimated to deliver 75 Mcfd during the first year, or one-half the rate of the well with the greatest projected potential. Additionally because of the increased friction associated with the smaller casing Well #6 was eliminated leaving three Candidate Wells: Riddle I-1, Florance GCL-1, and Florance Q-1

1. Electric Logs
   a. Candidate Well # 1 - Florance GCL-1 (29336)
      The electric log indicating the perforated intervals follows below.

   b. Candidate Well # 2 – Florance Q-1 (29345)
      The electric log indicating the perforated intervals follows below.

   c. Candidate Well # 3 – Riddle I-1 (29328)
      The electric log indicating the perforated intervals follows below.

2. Completion
   The completions involved running geophysical logs to identify potential gas bearing intervals prior to installing steel casing and cementing it across the Fruitland Coals. The casing was then perforated at specific depths which had been identified on the logs, and then hydraulically stimulated. The stimulation treatments were generally with nitrogen foam containing 250,000 pounds of 20/40 sized sand proppant which was pumped through the perforations.

   Amoco's practices utilized a large number of perforations which in the three Candidate Wells ranged from 200 to 316 over intervals of 120 to 180 feet. Typically the stimulations were N_2 foam with viscosities on the order of 300 cp as compared to liquid CO_2 with 0.1 cp. This large number of perforations significantly reduced the transport velocity, and compromised the ability to transport proppant.

Typically 30 perforations are used with the CO_2/sand treatments. The resultant per-perforation transport velocity being 158 feet per second (fps). With 258 perforations, the average for the Candidate Wells, the velocity diminished to 18.4 fps which is much less than the settling velocity.

It was therefore predictable that the ability to transport proppant with liquid CO_2 at the reduced flow rate resulting from the large number of perforations would be very unlikely.

The knowledge of the placement of this large number of perforations was not conveyed to the contractor until the equipment was on location and the preparations to initiate the pumping operations nearly complete.

3. Perforation Strategy

The perforation placements were identified from the electric logs and positioned at the coal intervals which have lower bulk densities. The accompanying electric logs (Figures 7 to 9) indicate this placement technique.

Well	Interval (ft)	Perfs
Riddle I-1	120	200
Florance GCL-1	180	316
Florance Q-1	158	288

Figure 7 – Florance GCL-1 (p. 1 of 2)

MARKED

HALLIBURTON

DUAL SPACED NEUTRON LOG

COMPANY AMOCO PROCDUCTION CO.
WELL FLORANCE GAS COM "L"NO.1
FIELD PICTURED CLIFFS
COUNTY SAN JUAN
STATE N.M
COUNTY SAN JUAN STATE N.M

COMPANY AMOCO PROCDUCTION CO.
WELL FLORANCE GAS COM "L"NO.1
FIELD PICTURED CLIFFS
COUNTY SAN JUAN STATE N.M

API No. N/A
Location N/A
Sect 20 Twp 28N Rge

Other Services

Permanent Datum GROUND Elev N/A
Log measured from K.B . 12 ft. above perm. datum
Drilling measured from K.B.

Elev.: K.B. ____ D.F. ____ G.L. ____

Date @ Time Logged	1-10-96 @12:00	Type fluid in hole	WATER
Run No.	ONE	Density of Fluid	N/A
Depth - Driller	N/A	Fluid Level	FULL
Depth - Logger	2206	Cement Top Est. Logged	N/A
Bottom - Logged Interval	2200	Equipment / Location	50623 / FARM
Top - Logged Interval	1200	Recorded by	GILLINGHAM
Max. rec. temp., deg F.	N/A	Witnessed by	L.HUMPHREY

CEMENTING DATA	Surface String	Protection String	Production String	Liner
Date/Time Cemented				
Primary/Squeeze				
Expected Compressive Strength	psi@ hrs	psi@ hrs	psi@ hrs	psi@ hrs
Cement Volume				
Cement Type / Weight	/	/	/	/
Formulation				
MUD Type / MUD Wgt.	/	/	/	/

RUN	BOREHOLE RECORD			CASING & TUBING RECORD			
No.	Bit	From	To	Size	Wgt.	From	To
				7.0		SURF	N/A
				4.5		SURF.	N/A

Figure 7 – Florance GCL-1 (p. 2 of 2)

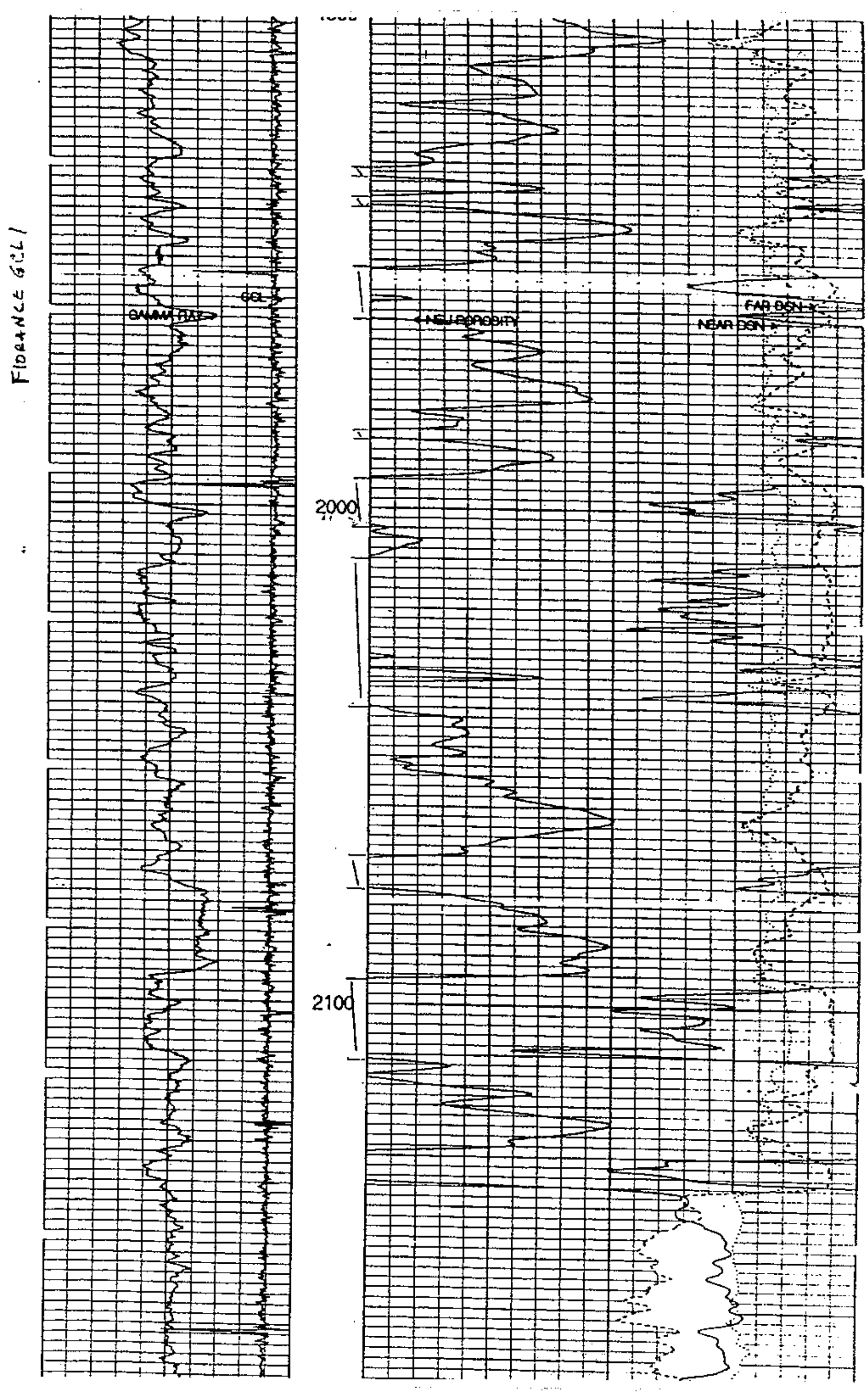


Figure 8 – Florance Q-1 (p. 1 of 2)

MAILED

HALLIBURTON

SPECTRAL DENSITY
DUAL SPACED NEUTRON

COMPANY AMOCO PRODUCTION CO.
WELL FLORENCE Q #1
FIELD FRUITLAND COAL
COUNTY SAN JUAN STATE NM

COMPANY AMOCO PRODUCTION COMPANY
WELL FLORENCE Q #1
FIELD FRUITLAND COAL
COUNTY SAN JUAN STATE NM
API NO N/A
LOCATION

OTHER SERVICES
HRI
MICROLOG

SECT 29 TWP 28N RGE 08W

PERMANENT DATUM G.L. ELEV. 5822
LOG MEASURED FROM K.B. OR 8 FT.ABOVE PERM DATUM
DRILLING MEASURED FROM KELLY BUSHING

ELEV.: K.B. 5830
D.F. 5829
G.L. 5822

DATE	01-05-96			
RUN NO.	ONE			
DEPTH-DRILLER	2252			
DEPTH-LOGGER	2264			
BTM. LOG INTER	2230			
TOP LOG INTER	262			
CASING DRILLER	7.0 @ 250	@	@	@
CASING-LOGGER	262			
BIT SIZE	6.25			
TYPE FLUID IN HOLE	LSND			
DENS. : VISC.	9.2 : 60	:	:	:
PH. : FLUID LOSS	8.0 : 5.0	:	:	:
SOURCE OF SAMPLE	FLOWLINE			
RM @ MEAS. TEMP.	1.82 @ 44	@	@	@
RMF @ MEAS. TEMP.	1.36 @ 44	@	@	@
RMC @ MEAS. TEMP.	2.27 @ 44	@	@	@
SOURCE RMF:RMC	CALC :CALC	:	:	:
RM @BHT	0.83 @ 105	@	@	@
TIME SINCE CIRC	4 HOURS			
TIME ON BOTTOM	10:45	01-05-96		
MAX. REC TEMP.	105 @T.D	@	@	@
EQUIP : LOCATION	51943:FARM	:	:	:
RECORDED BY	MATT BREWER			
WITNESSED BY	S. GATHINGS			

Figure 8 – Florance Q-1 (p. 2 of 2)

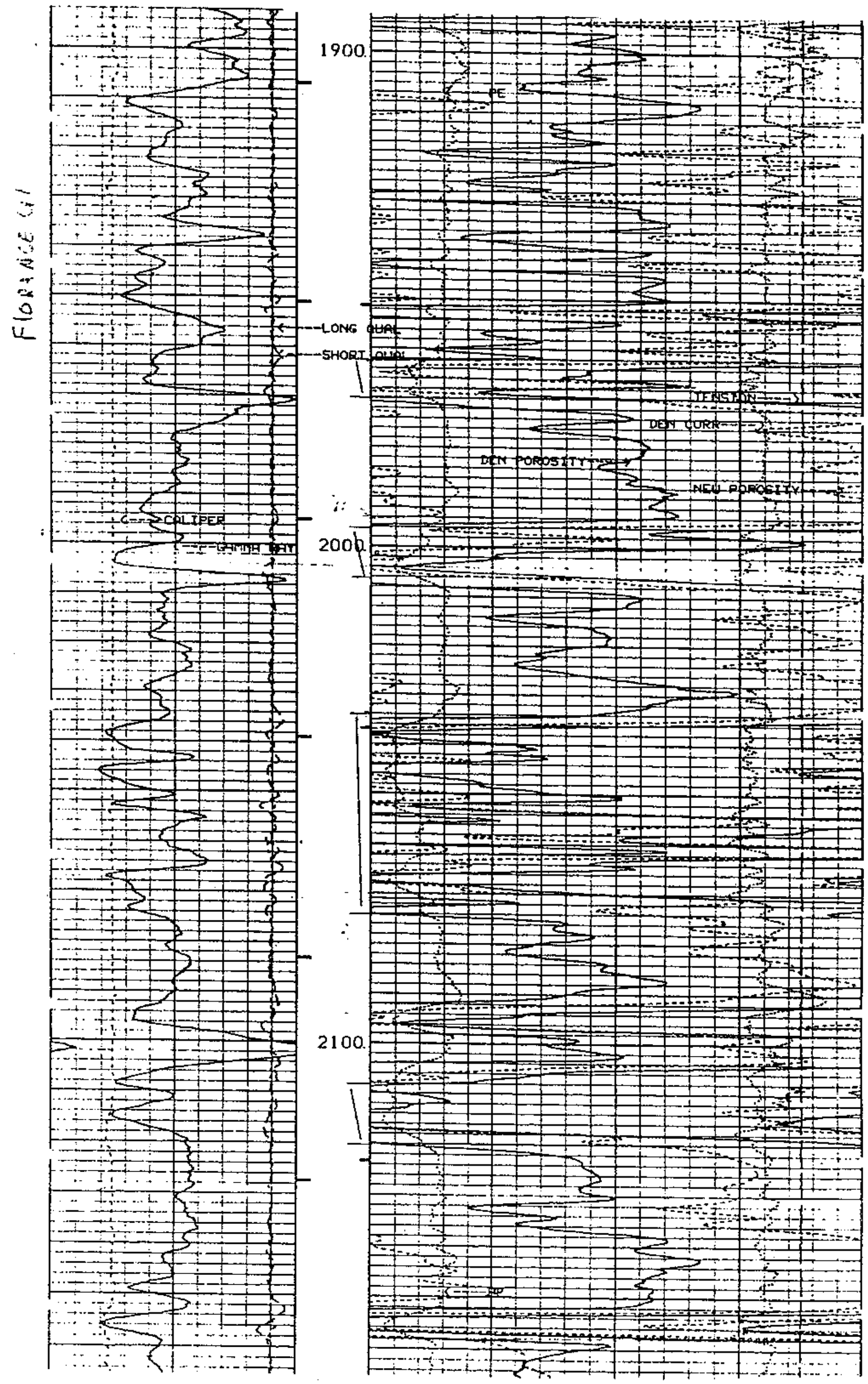


Figure 9 – Riddle I-1 (p. 1 of 2)

HALLIBURTON

SPECTRAL DENSITY
DUAL SPACED NEUTRON

COMPANY AM J PRODUCTION CO
WELL RIDDLE I #1
FIELD FRUITLAND COAL
COUNTY SAN JUAN STATE NM

COMPANY AMOCO PRODUCTION COMPANY
WELL RIDDLE I #1
FIELD FRUITLAND COAL
COUNTY SAN JUAN STATE NM
API NO N/A OTHER SERVICES
LOCATION 1020 FT. FNL & 1090 FT. FEL HRI

SECT 20 TWP 29N RGE 09W
PERMANENT DATUM G.L. ELEV. 5909
LOG MEASURED FROM K.B. OR 8 FT. ABOVE PERM DATUM
DRILLING MEASURED FROM KELLY BUSHING
ELEV.:K.B. 5917 D.F. 5918 G.L. 5909

DATE	01-03-96			
RUN NO	ONE			
DEPTH-DRILLER	2270			
DEPTH-LOGGER	2277			
BTM. LOG INTER	2274			
TOP LOG INTER	264			
CASING DRILLER	7.0 @257	@	@	@
CASING LOGGER	264			
BIT SIZE	6.25			
TYPE FLUID IN HOLE	LSND			
DENS. | VISC	8.9 | 100	|	|	|
PH | FLUID LOSS	N/A | 8	|	|	|
SOURCE OF SAMPLE	FLOWLINE			
RM @ MEAS. TEMP	3.05 @52	@	@	@
RMF @ MEAS. TEMP	2.74 @52	@	@	@
RMC @ MEAS. TEMP	3.81 @52	@	@	@
SOURCE RMF RMC	CALC | CALC	|	|	|
RM @ BHT	1.50 @101	@	@	@
TIME SINCE CIRC.	4 HOURS			
TIME ON BOTTOM	00:15			
MAX. REC TEMP	101 @7.0	@	@	@
EQUIP. & LOCATION	5134 | FARM	|	|	|
RECORDED BY	JOHN GAYNGE			
WITNESSED BY	ROTHENBERG			

FOLD HERE

SERVICE TICKET NO.: 849788 API SERIAL NO.: SAME PGM VERSION: 2.72

CHANGE IN MUD TYPE OR ADDITIONAL SAMPLES			RESISTIVITY SCALE CHANGES			
DATE: SAMPLE NO.	/ / |	/ / |	TYPE LOG	DEPTH	SCALE UP HOLE	SCALE DOWN HOL
DEPTH-DRILLER						
TYPE FLUID IN HOLE						
DENS. | VISC	|	|				
PH | FLUID LOSS	|	|				
SOURCE OF SAMPLE						

			RESISTIVITY EQUIPMENT DATA				
RM @ MEAS TEMP	@	@	RUN NO	TOOL TYPE & NO	PAD TYPE	TOOL POS.	OTHE
RMF @ MEAS TEMP	@	@	N/A	HRI GA075		FREE	
RMC @ MEAS TEMP	@	@					
SOURCE: RMF: RMC	:	:					
RM @ BHT	NA @	@					
RMF @ BHT	NA @	@					
RMC @ BHT	NA @	@					

EQUIPMENT DATA

GAMMA		ACOUSTIC		DENSITY		NEUTRON	
RUN NO.	ONE	RUN NO.		RUN NO.	ONE	RUN NO.	ONE
SERIAL NO.	B188582	SERIAL NO.		SERIAL NO.	RED	SERIAL NO.	B18878
MODEL NO.	NGRT	MODEL NO.		MODEL NO.	SDLT-A	MODEL NO.	DSN
DIAMETER	3.625	NO. OF CENT.		DIAMETER	4.50	DIAMETER	3.625
DETECTOR MODEL NO.	S-1	SPACING		LOG TYPE	GR-CN	LOG TYPE	NEU-NEU

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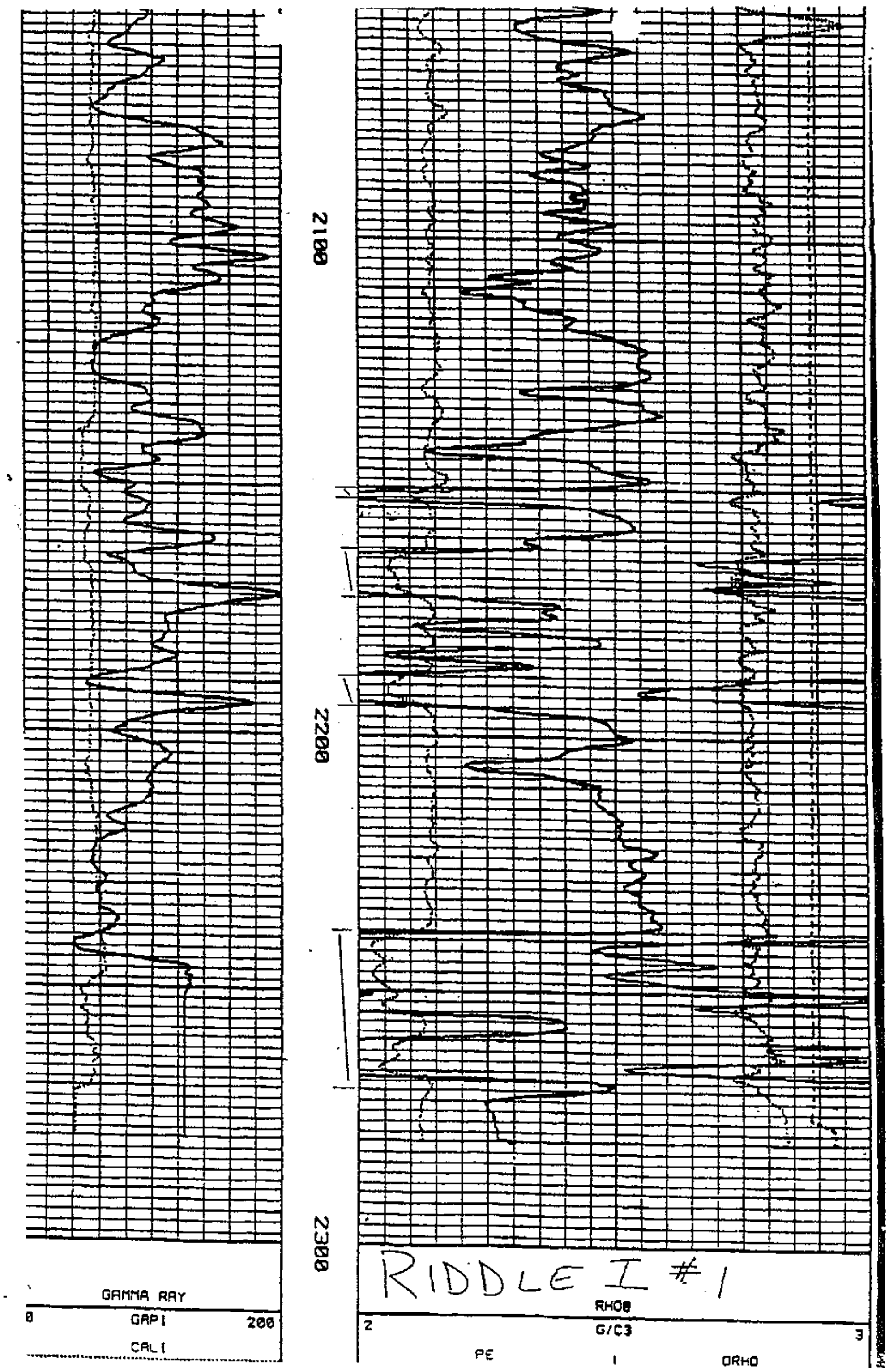
Figure 9 – Riddle I-1 (p. 2 of 2)



XIII. CO_2/SAND STIMULATION TREATMENTS

A. Design

The stimulation designs were developed from the observed pressure-injection history for nitrogen foam stimulations on wells approximately seven miles distant.

The current practice was to complete the wells with 2-7/8 inch production tubulars. However, for the purposes of this evaluation, three of the initially offered Candidate Wells were completed with 4-1/2 inch production casing, and one, a plug back, Storey D2, with 3-1/2 inch tubulars. Because of the concerns of excessive friction pressures in the smaller diameter casing in the Storey D2 it was rejected leaving three Candidate Wells all with 4-1/2 inch casing.

The larger diameter tubulars enabled greater pumping rates, 40-55 barrels per minute, to be achieved without the excessive pressure drops resulting from the increased friction associated with the smaller diameter casing.

B. Fracturing Gradient

The fracturing gradient was estimated from wells located in the same township (28N) within seven miles of the Candidate Wells, three were situated approximately seven miles east of the Candidate Wells, where the Fruitland Coal is at a depth of approximately 3,200 feet. Fracturing pressure gradient information was also obtained from another well located approximately 1.2 miles west of the Candidate Wells, where the coal lies at a depth of approximately 2,100 feet.

The individual well depths and instantaneous shut-in pressures are tabulated and plotted, and the fracturing gradient for the Candidate Wells is projected to be 0.67 psi per foot or at a bottom hole pressure of 1,742 psi.

C. Hydrostatic Pressure

The hydrostatic wellhead pressure for 2,600 feet of liquid CO_2 with a bottom hole pressure of 1,742 psi was projected to be 1,379 psi.

D. Friction Pressure

The friction pressure drops in the tubulars (2,600 ft) and the perforations were estimated as follows:

Friction Pressure (psi)			
Injection Rate (bpm)	40	50	60
Diameter (in) 3.5	2,771	3,771	4,783
4.5	1,105	1,334	1,461

E. Treating Pressure

The estimated treating pressures and the associated horsepower requirements were tabulated and are also presented graphically. It is clearly evident that the smaller diameter 3.50 inch tubular will require significant additional horsepower over that of those wells equipped with 4.5 inch casing.

At a minimum recommended pumping rate of 40 barrels per minute (bpm) the 3.50 inch tubular requires 4,069 hydraulic horsepower as compared to 2,435 for the larger diameter casing. The incremental cost for the additional horsepower was estimated at $4.65 per horsepower to be $7,598.

The wellhead treating pressures and horsepower requirements were then estimated to be:

Wellhead Treating Pressure/HHP (psi)			
Injection Rate (bpm)	40	50	60
Diameter (in) 3.5	4,150/4,069	5,150/6,311	6,162/9,062
4.5	2,484/2,435	2,713/3,325	2,840/4,176

F. Sand Schedule

The treatments were to consist of 120 tons of CO_2 per stage and were projected to yield a net of 500 barrels (96 tons) of CO_2 in-zone along with 40,320 pounds of 20/40 proppant per stage.

The individual well treatment designs were developed based upon sand acceptance concentrations in the offset wells, and the intention was to modify them as the treatment sequence progressed, the objective being to place the maximum sand volumes. With this in mind full blender volumes of 47,500 lbs of proppant were loaded

G. Proppant Size

20/40 (USS) sand proppant was successful in the previous stimulations, and on that basis was proposed in the design

H. Treatment Volume

The Control Wells utilized 250,000 lbs of proppant which was placed with N_2 foam stimulations, and it was obvious that placing the largest proppant volume would be the objective.

I. Recommended Design

The recommended stimulation design for the first Candidate Well was:

PROPPANT FLUID SCHEDULE					
	Cum Fluid	Stage Fluid	Proppant Conc	Proppant Stage	Cum Proppant
	(bbl)	(bbl)	(ppg)	(lb)	(lb)
Stage					
Hole Fill (Liquid CO_2)	30	30		0	0
Pad (Liquid CO_2)	120	90		0	0
Start (20/40 Sand)	190	70	1.0	2,940	2,940
Increase (20/40 Sand)	230	40	2.0	3,360	6,300
Increase (20/40 Sand)	500	270	3.0	34,020	40,320
Flush (Liquid CO_2)	525	25		0	
Total		525			40,320

TREATMENT FLUID REQUIREMENTS						
	Hole +	Prop	Flush	Tot	Bottoms	Total
Liq CO_2	120	380	25	525	10	535
CO_2 (T)						103
N_2 (Mscf)						61

The plan was to determine the sand acceptance rates, and then to modify the sand schedule accordingly. All of the treatments were to include 120 tons of CO_2 on site which after cool down and bottoms would provide approximately 525 bbls of CO_2 for the stimulation.

J. Treatment Volume Comparison - Conventional vs CO_2/Sand

In actuality only limited proppant volumes were placed. All of the treatments were terminated prior to the maximum proppant volume being pumped. One screened out and the proppant concentrations on the other two were reduced as it became evident that the acceptance rate was less than the design. This reduced acceptance rate is believed to be a consequence of the large number of perforations (200 to 316) which significantly reduced the transport velocity.

XIV. CRITERIA FOR SUCCESS

Amoco reviewed the production data from the offset wells, and their Oklahoma based statistician indicated that the following comparisons are valid for a bimodal distribution. This relation results in a statistically defensible comparison between the Control Well population (n = 9 wells) with a large standard deviation, 56%, and the Candidate Well population (n = 6 wells).

Population	Control	Candidate
Mean (Mcfd)	104	135
Std Deviation (%)	56	56
n	9	6

Using this criteria the production from CO_2\sand stimulated Candidate Wells must be greater than 135 Mcfd to be statistically significant.

This was considered to be a realistic goal for the Candidate Wells and to be reasonably attainable. The multiplier for the increased cost of the treatments should be approximately 20% of the well cost resulting in an economically defensible hurdle rate of 162 Mcfd, which was considered to be reasonable.

XV. PRE-TEST CONCLUSIONS

The three Candidate Well sites offered by Amoco were considered to provide a meaningful opportunity for demonstrating and evaluating the CO_2/Sand stimulation technology. In addition, Amoco was very interested in this area in terms of understanding the geology, reservoir, and completion techniques, and it was considered likely that if the technology proved successful that additional exploitation would occur.

In retrospect it is now concluded that this endeavor was an attempt to apply the technology where there was little promise for conventional stimulation treatments.

XVI. DOE APPROVALS

A submittal package (#2) was prepared and submitted to the DOE for consideration. After their review and some additional information provided, the treatments were approved for a cost-shared demonstration.

XVII. FIELD ACTIVITIES

A. Preparations

The wells were perforated during the week prior to the treatments, CO_2 was procured and the service company mobilization, from Pennsylvania with support from Canadian Fracmaster pump trucks from Edmonton, Alberta initiated.

B. Comments

The sand schedule evolved during these treatments where it became apparent that only limited sand volumes would be placed with the proposed schedule. The first two (2) wells treated (Florance GCL-1 and Florance Q-1) screened out with 75 and 48 sacks of sand, respectively, through the perforations.

Both wells exhibited immediate wellhead pressure decays to approximately 300 psi following the treatments, indicating a very high rate of leak off. The conclusions following these treatments were that:

1. The high leak off rates combined with the numerous individual coal members perforated were resulting in low transport velocities and minimum induced fracture widths.

2. The ability to place sand into subsequently initiated fractures, i.e., fractures not initiated at the beginning of the treatment when the sand concentrations were either low or non-existent, was impossible because there was no pad liquid ahead of the higher concentration - sand laden slurry.

It should also be recognized that the pressure decay at the end of the third treatment was much slower than that observed on the first two wells, suggesting considerably reduced leak off into a less permeable formation.

C. Stimulations

1. Florance GCL-1 (29336) -- Candidate Well # 1

The Florance GCL-1 was the first well stimulated. It had been perforated previously with 316 holes over a 180 foot interval from 1,931 to 2,111 feet.

The pressurized blender was transported to the well site on the day of the treatment, January 16, 1996 and filled with 20/40 sand. The treatment was then executed. A pad volume of 90 bbls was pumped prior to initiating sand proppant at 1.0 ppg. 9,800 lbs of proppant were pumped in 137 bbls of CO_2 at an average rate and pressure of 55.8 barrels per minute and 2,226 psi respectively.

The well screened out with 7,500 lbs of proppant through the perforations.

The maximum sand concentration was 2.5 lbs per gal, and averaged 1.6, the maximum rates and pressures were 60.2 Bpm and 3,576 psi respectively. The treatment was halted when the treatment screened out at a wellhead pressure of 3,576 psi. The stimulation pressure-rate history plot is included (Figures TBD and TBD). The in zone proppant volume was estimated 7,500 pounds.

Figure 10 – Florance GCL-1

UNIVERSAL WELL SERVICES INC

AMOCO

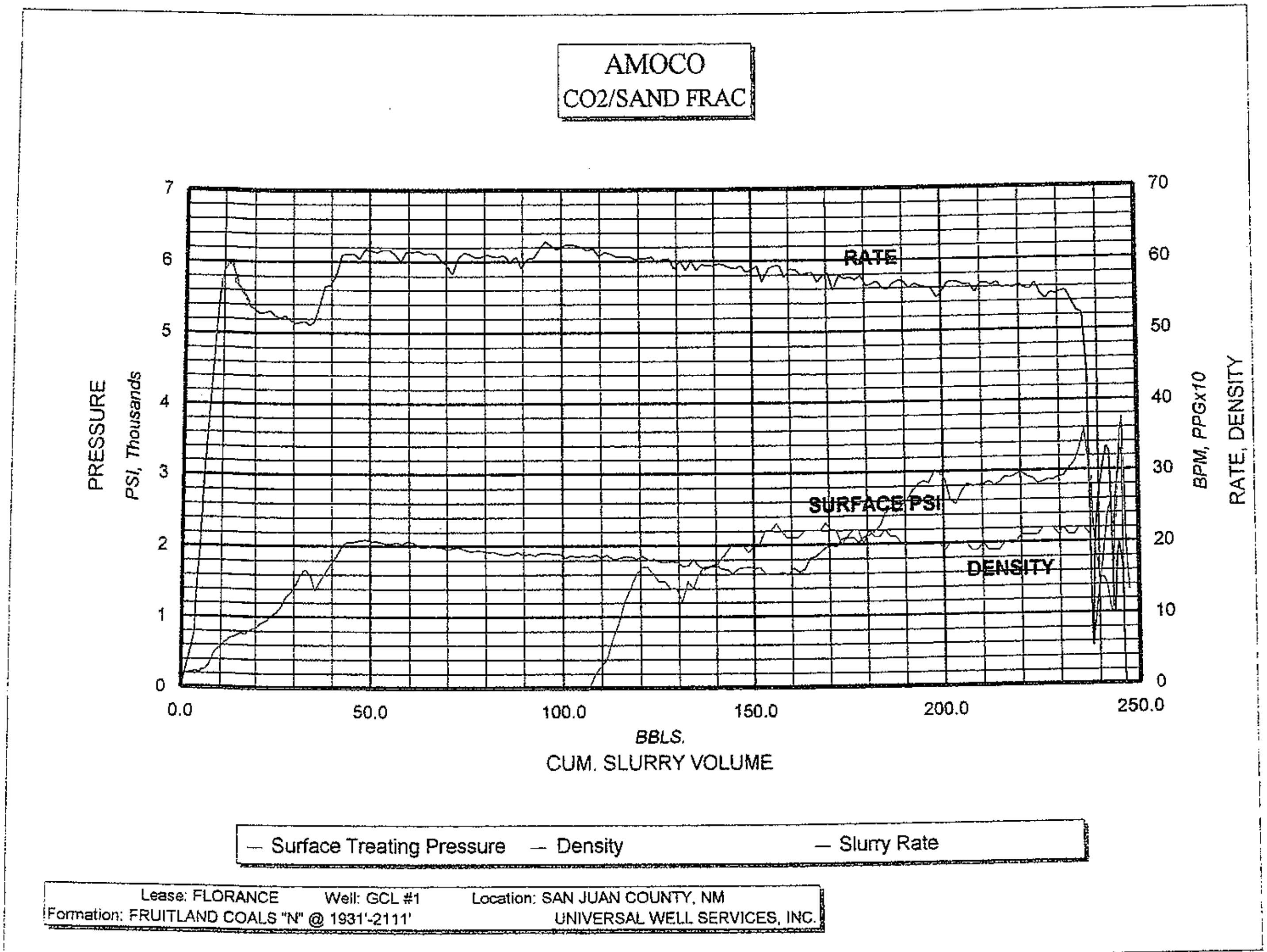
Date:	12/16/95
Lease:	FLORANCE
Formation:	FRUITLAND COAL
Well:	GCL-1
Treatment:	CO2 / Sand Frac through 4.5" casing

Cumulative Clean Volume *BBLS*	**Stage Clean Volume** *BBLS*	**Sand Concentration** *PPG*	**Stage Slurry Volume** *BBLS*	**Cumulative Slurry Volume** *BBLS*	**Cumulative Sand** *SKS*
90	90	PAD	90	90	0
130	40	1	42	132	17
227	97	2	106	238	98

*** SHUT DOWN, MAXIMUM PRESSURE. ***

Breakdown Pressure	1650 PSI	**ISIP (End of Job)**	PSI
Max. Pressure	3576 PSI	**Max. Rate**	60.2 BPM
Avg. Pressure	2226 PSI	**Avg. Rate**	55.8 BPM
Max. Horsepower	4497 HHP	**Max. Sand Conc.**	2.5 PPG
Avg. Horsepower	4139 HHP	**Avg. Sand Conc.**	2.4 PPG
Total Proppant	98 SKS	**Prop. Type**	20/40
Total Clean CO2	227 BBLS		

Figure 11 – Florance GCL-1



2. Florance Q-1 (29345) – Candidate Well #2

The Florance Q-1 was the second well to be stimulated. It had been perforated previously with 288 holes over a 158 foot interval from 1,962 to 2,120 feet.

An effort to increase the placed volume included increasing the pad volume from 90 to 148 barrels along with an increase in the initial sand concentration from 1.0 to 1.5 pounds per gallon (ppg). A total sand-laden CO_2 volume of 101 bbls was pumped which was less than the 137 pumped in the first well treated, Candidate Well #2, Florance GCL-1.

The pressurized blender was moved to the well site on the day of the treatment, January 16, 1996 and filled with 20/40 sand. The treatment was then executed, 6,200 lbs of proppant were pumped at an average rate and pressure of 55.8 barrels per minute and 2,145 psi respectively. The maximum sand concentration was 1.9 lbs per gal, and averaged 1.5, the maximum rates and pressures were 60.2 Bpm and 4,100 psi respectively. The treatment was halted when the treatment screened out at a wellhead pressure of 4,100 psi. The stimulation pressure-rate history plot is included (Figures 12 and 13). The in zone proppant volume was estimated 4,800 pounds.

Figure 12 – Florance Q-1

UNIVERSAL WELL SERVICES INC

AMOCO

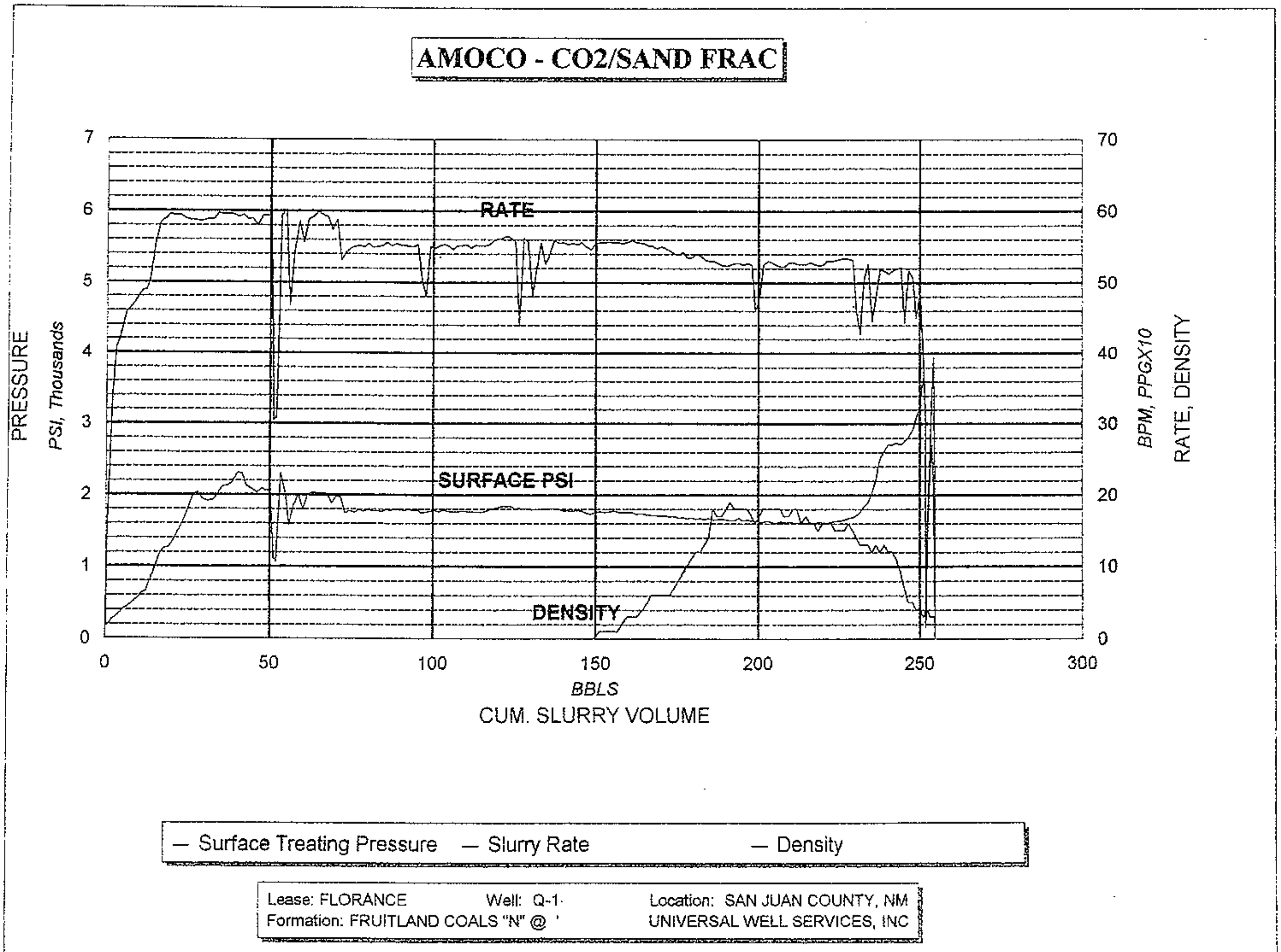
Date: 12/16/95
Lease: FLORANCE
Formation: FRUITLAND COAL
Well: Q-1
Treatment: CO2 / Sand Frac through 4.5" casing

Cumulative Clean Volume *BBLS*	Stage Clean Volume *BBLS*	Sand Concentration *PPG*	Stage Slurry Volume *BBLS*	Cumulative Slurry Volume *BBLS*	Cumulative Sand *SKS*
150	150	PAD	150	150	0
249	99	1.5	105	255	62

*** SHUT DOWN, MAXIMUM PRESSURE. ***

Breakdown Pressure	2150 PSI	**ISIP (End of Job)**	PSI
Max. Pressure	4100 PSI	**Max. Rate**	60.2 BPM
Avg. Pressure	2145 PSI	**Avg. Rate**	55.8 BPM
Max. Horsepower	4228 HHP	**Max. Sand Conc.**	1.9 PPG
Avg. Horsepower	2934 HHP	**Avg. Sand Conc.**	1.49 PPG
Total Proppant	62 SKS	**Prop. Type**	20/40
Total Clean CO2	249 BBLS		

Figure 13 – Florance Q-1



3. Riddle I-1 (29328) -- Candidate Well #3

The Riddle I-1 was the third well stimulated. It had been perforated previously with 200 holes over a 120 foot interval from 2,150 to 2,270 feet.

The treatment was modified and it was considerably more successful in that 130 sacks of sand were placed in zone.

The design was recommended by Amoco and included a pad volume similar in size to the first treatment (88 vs. 90), but also included a 20 barrel "slug" of 0.5 ppg sand in the middle of it. Additionally, the sand concentrations were lower at the outset 0.5ppg and averaged, 1.0 ppg or less, throughout the majority of the treatment. The results were improved in that 13,000 lbs were placed in zone

The pressurized blender was transported to the well site on the day of the treatment, January 17, 1996 and filled with 20/40 sand. The treatment was then executed, 15,200 lbs of proppant were pumped at an average rate and pressure of 50.0 barrels per minute and 2,517 psi respectively. The maximum sand concentration was 1.9 lbs per gal, and averaged 0.8, the maximum rates and pressures were 56.0 Bpm and 4,702 psi respectively. The treatment was halted when the treatment screened out at a wellhead pressure of 4,702 psi. The stimulation pressure-rate history plot is included (Figures 14 and 15). The in zone proppant volume was estimated 13,000 pounds.

Figure 14 – Riddle I-1

UNIVERSAL WELL SERVICES INC

AMOCO

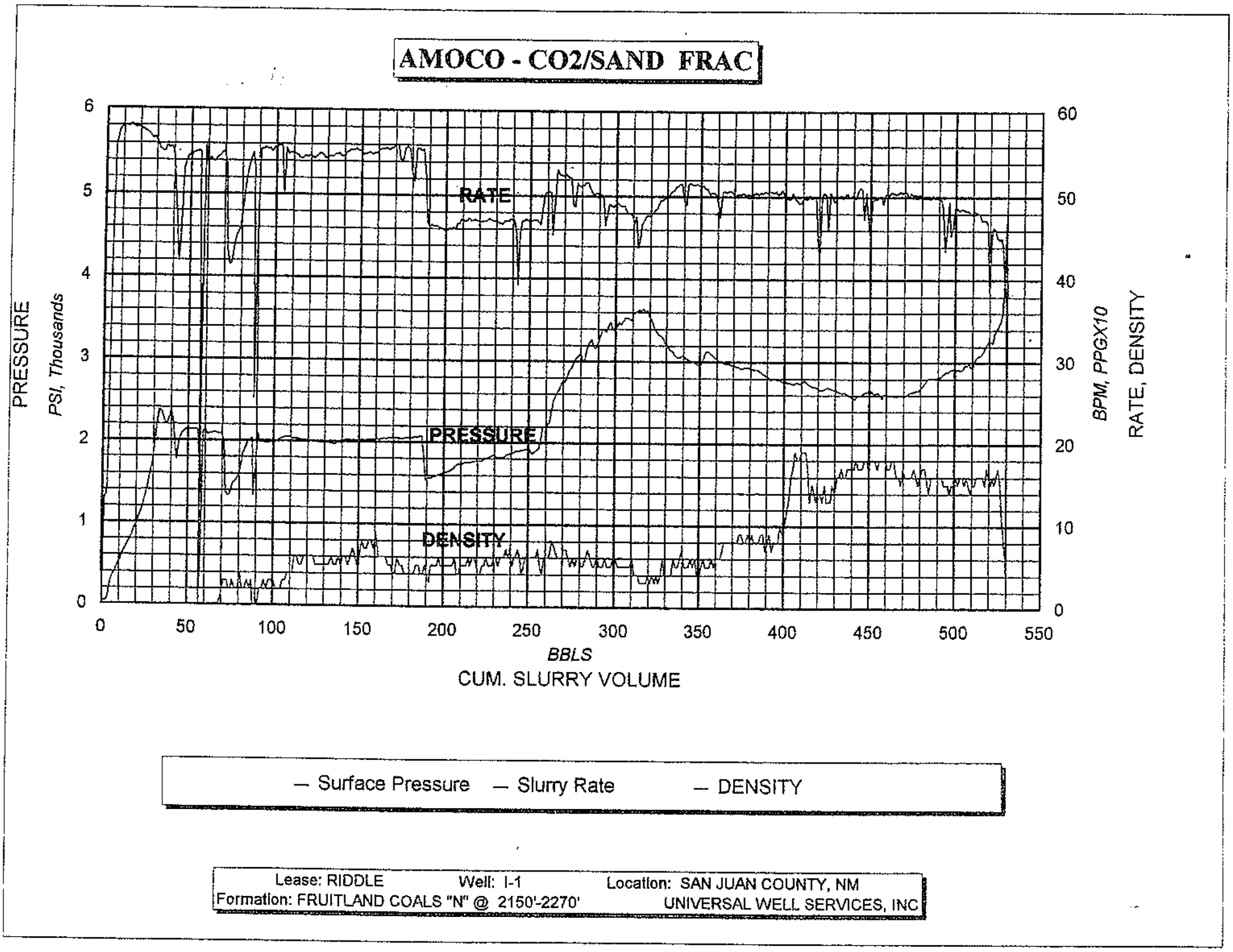
Date:	12/17/96
Lease:	RIDDLE
Formation:	FRUITLAND COAL
Well:	I-1
Treatment:	CO2 / Sand Frac through 4.5" casing

Cumulative Clean Volume *BBLS*	**Stage Clean Volume** *BBLS*	**Sand Concentration** *PPG*	**Stage Slurry Volume** *BBLS*	**Cumulative Slurry Volume** *BBLS*	**Cumulative Sand** *SKS*
70	70	PAD	70	70	0
358	288	0.5	295	364	60
393	35	1	36	400	75
509	116	1.5	126	526	148
513	4	FLUSH	4	530	148

*** SHUT DOWN, MAXIMUM PRESSURE. ***

Breakdown Pressure	2365 PSI	**ISIP (End of Job)**	1300 PSI
Max. Pressure	4702 PSI	**Max. Rate**	56 BPM
Avg. Pressure	2517 PSI	**Avg. Rate**	50 BPM
Max. Horsepower	4228 HHP	**Max. Sand Conc.**	1.9 PPG
Avg. Horsepower	3076 HHP	**Avg. Sand Conc.**	0.8 PPG
Total Proppant	152 SKS	**Prop. Type**	20/40
Total Clean CO2	513 BBLS		

Figure 15 – Riddle I-1



The increased sand volume which was placed in this well is likely a result of:

a. The reduced number of perforations 200 vs. 288 and 316 in the other two Candidate Wells

b. The introduction of a 20 bbl 0.5ppg sand slug in the middle of the pad

c. Maintaining a reduced sand concentration of 0.75 ppg.

Note: The offset well to the Riddle I1 is completed in the PC Sandstone which underlies the Fruitland Coals. A gas sample was obtained following the treatment and was reported to contain 44% CO_2, indicating communication between these formations. The offset well was perforated in the basal section (Cahn) of the Fruitland Coal. The Candidate Well was not.

4. Stimulation Summary

All three wells screened out and the treatments were terminated. Following the screen out of the first treatment the pad volume was increased from 90 to 148 bbls and the starting sand concentration increased from 1.0 to 1.5 ppg yet a lesser in zone proppant volume resulted. This response indicates that increasing the pad volume provides no benefit, and that the ability to transport sand at concentrations of 1.0 ppg or greater is unlikely.

The largest sand volume was placed in the third treatment, Riddle I-1 which included a 20bbl - 0.5ppg sand slug in the pad and a reduced sand concentration of 0.75 ppg.

A contributing factor is believed to be the large number of perforations (200 to 316).

The "in-zone" sand volumes and other specifics were:

		Sand (sacks)		Max Tr Press	Avg Rate	Sand Conc (lb/gal)	
Well	Perfs	Pumped	In-Zone	Psi	BPM	Max	Avg
Florance GCL-1	316	98	75	3,576	55.8	2.5	1.6
Florance Q-1	288	62	48	4,100	55.8	1.9	1.5
Riddle I-1	200	152	130	4,702	50.0	1.9	0.8

D. Inter-zonal Communication between the Fruitland Coal and the PC Sandstone.

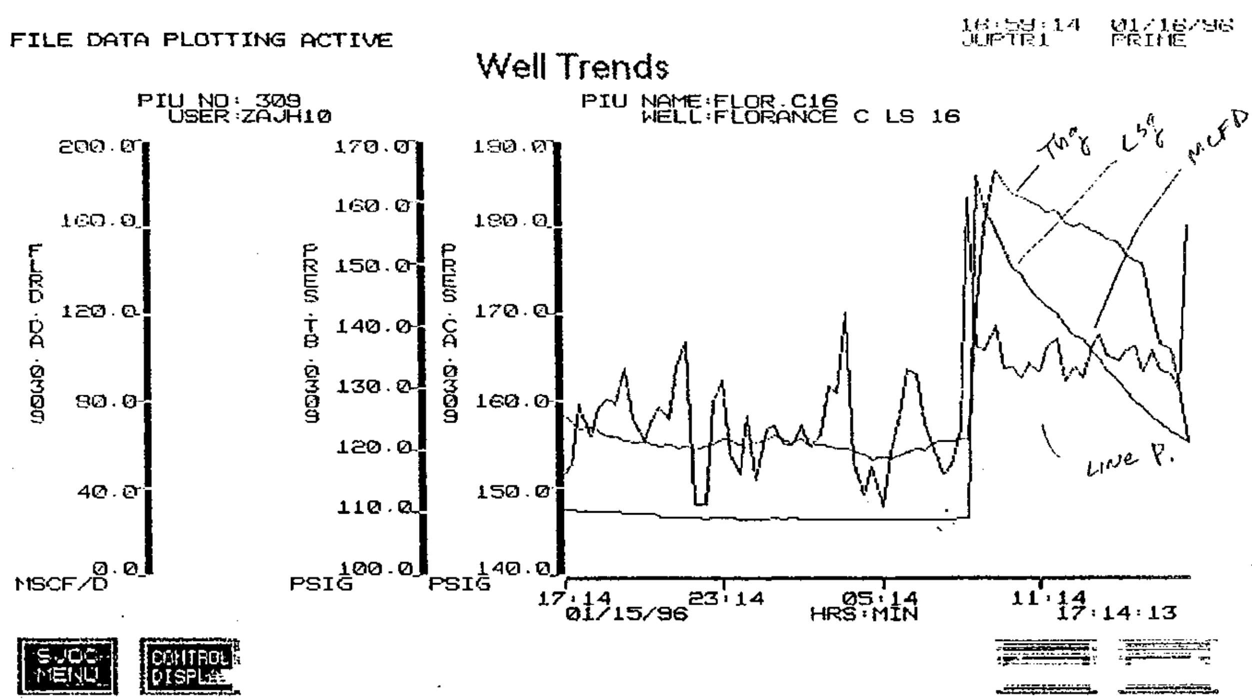
When stimulating all three of the Candidate Wells there were increases in production and/or casing pressure in the offset wells (on the same location) as the CO_2 treatments were being pumped.

These offset wells were completed in the Pictured Cliff Sandstone, but not the Fruitland Coals.

1. Florance GCL-1

The casing pressure in the offset well increased from 148 to 185 psi, and the production increased from 158 to 165 Mcf per day indicating the communication with the Candidate Well (Figure 16).

Figure 16 – Florance GCL-1

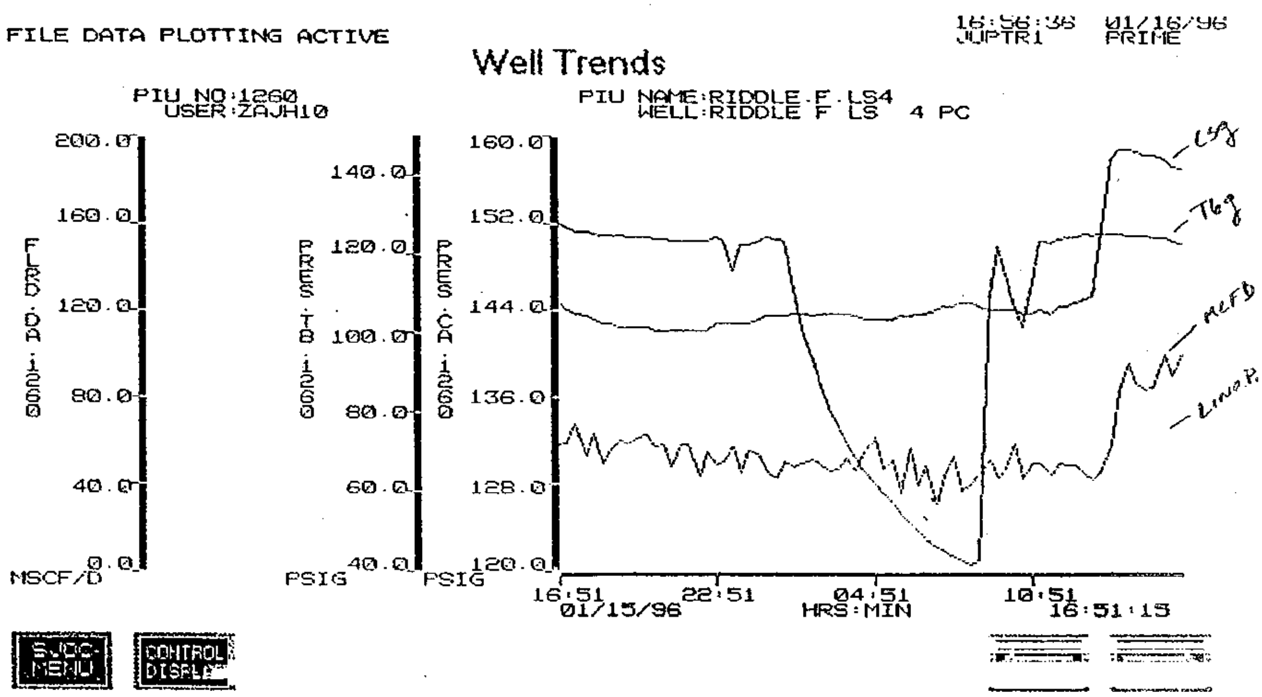


Within 50' of Florance GCL #1

2. Florance Q-1

The casing pressure in the offset well increased from 144 to 160 psi, and the production increased from 130 to 138 Mcf per day indicating the communication with the Candidate Well (Figure 17).

Figure 17 – Florance Q-1

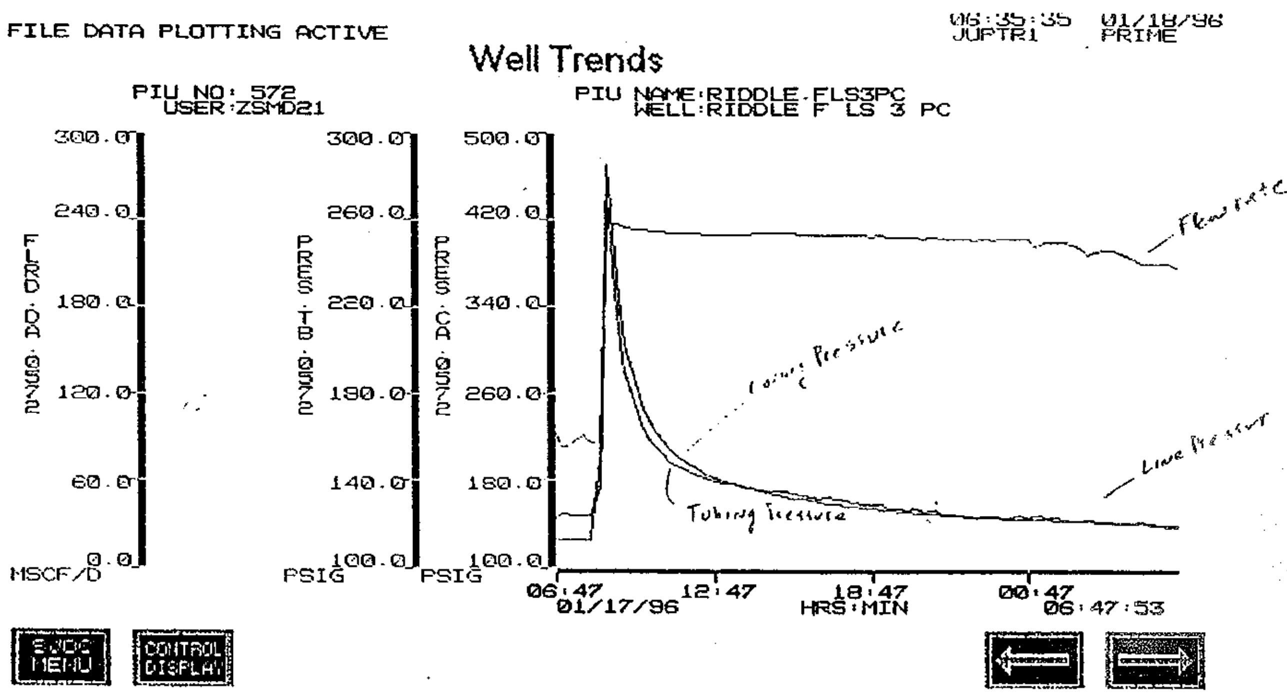


Within 50' of Florance Q #1

3. Riddle I-1

The casing pressure in the offset well increased from 127 to 460 psi, and the production increased from 190 to 420 Mcf per day indicating the communication with the Candidate Well (Figure 18). Additionally, a gas sample was obtained following the treatment and was reported to contain 44% CO_2, indicating communication between these formations. The offset well was perforated in the basal section (Cahn) of the Fruitland Coal. The Candidate Well was not.

Figure 18 – Riddle I-1



Within 50' of Riddle I #1

E. Post Stimulation

1. Flow Back Procedures

The wells were flowed back on 0.25 - 0.50 inch chokes and the wellhead pressure decayed to 70 - 80 psi in the Florance wells, the Riddle I1 decayed to 20 - 30 psi.

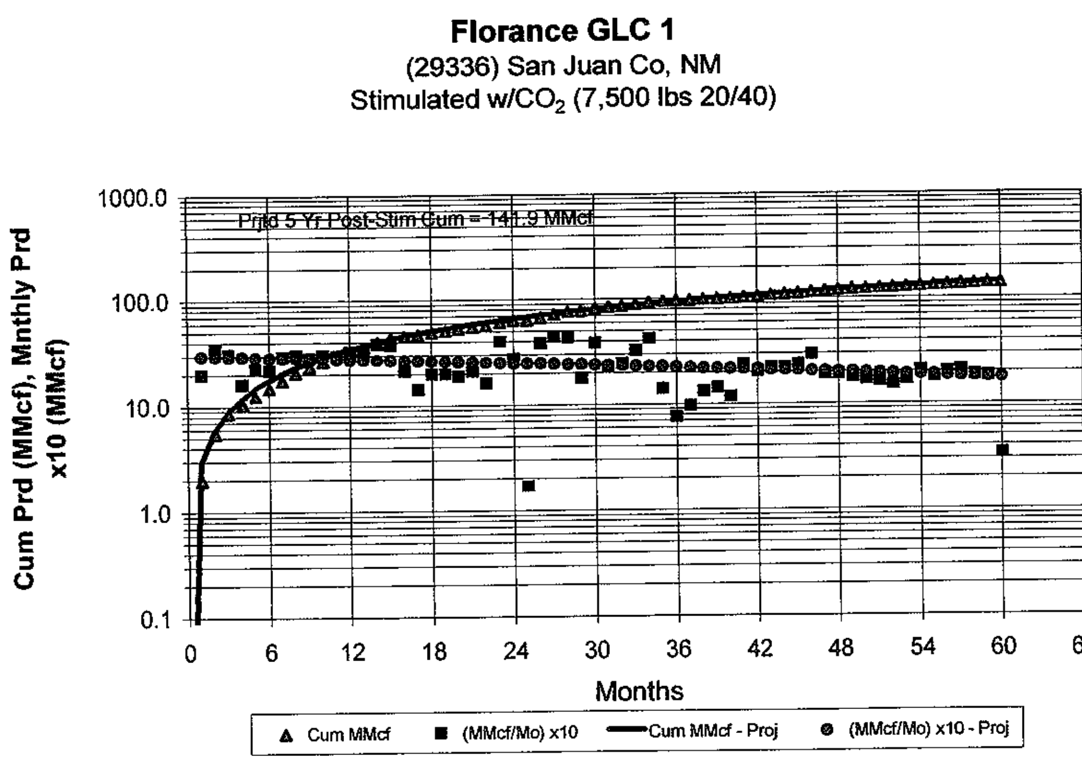
2. Cleaning Frac Sand from the Well Bore

All three wells have sand above the perfs which was cleaned out without introducing any liquid

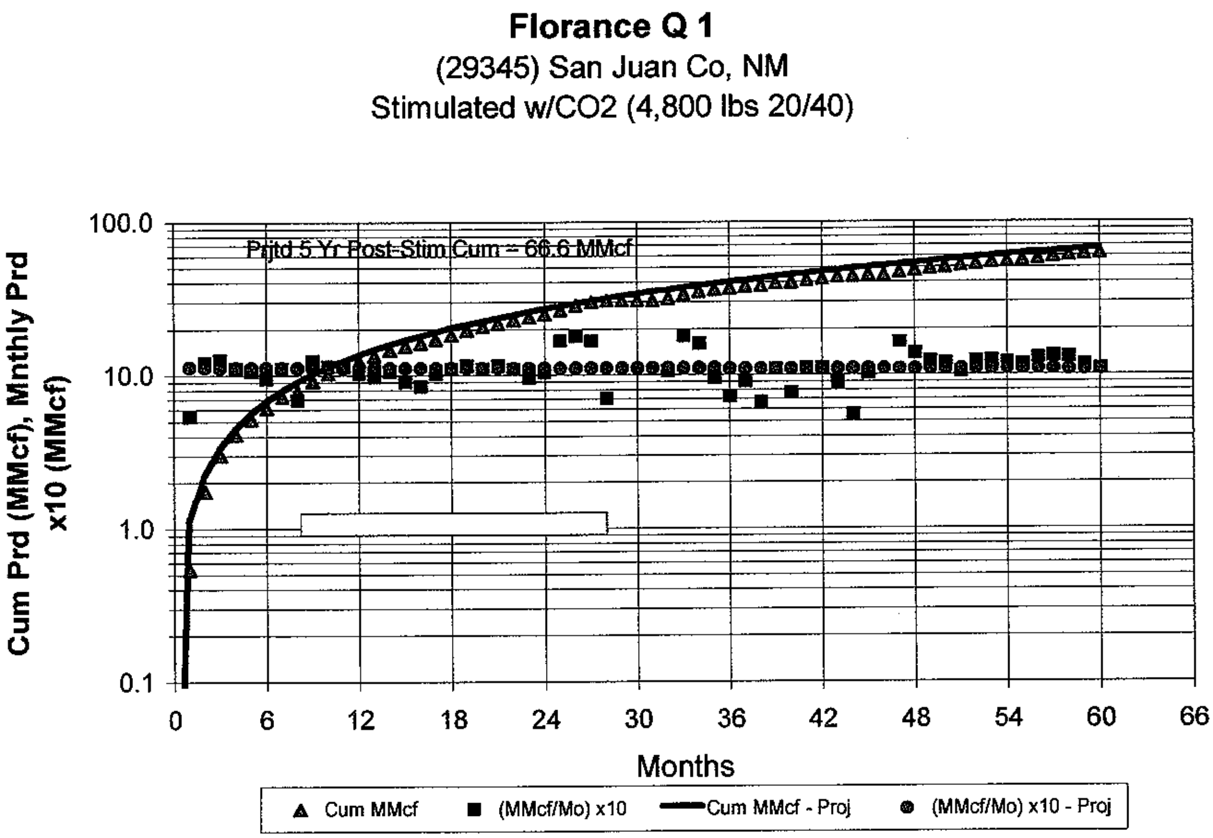
XVIII. RESULTS

A. Production Review – Candidate Wells

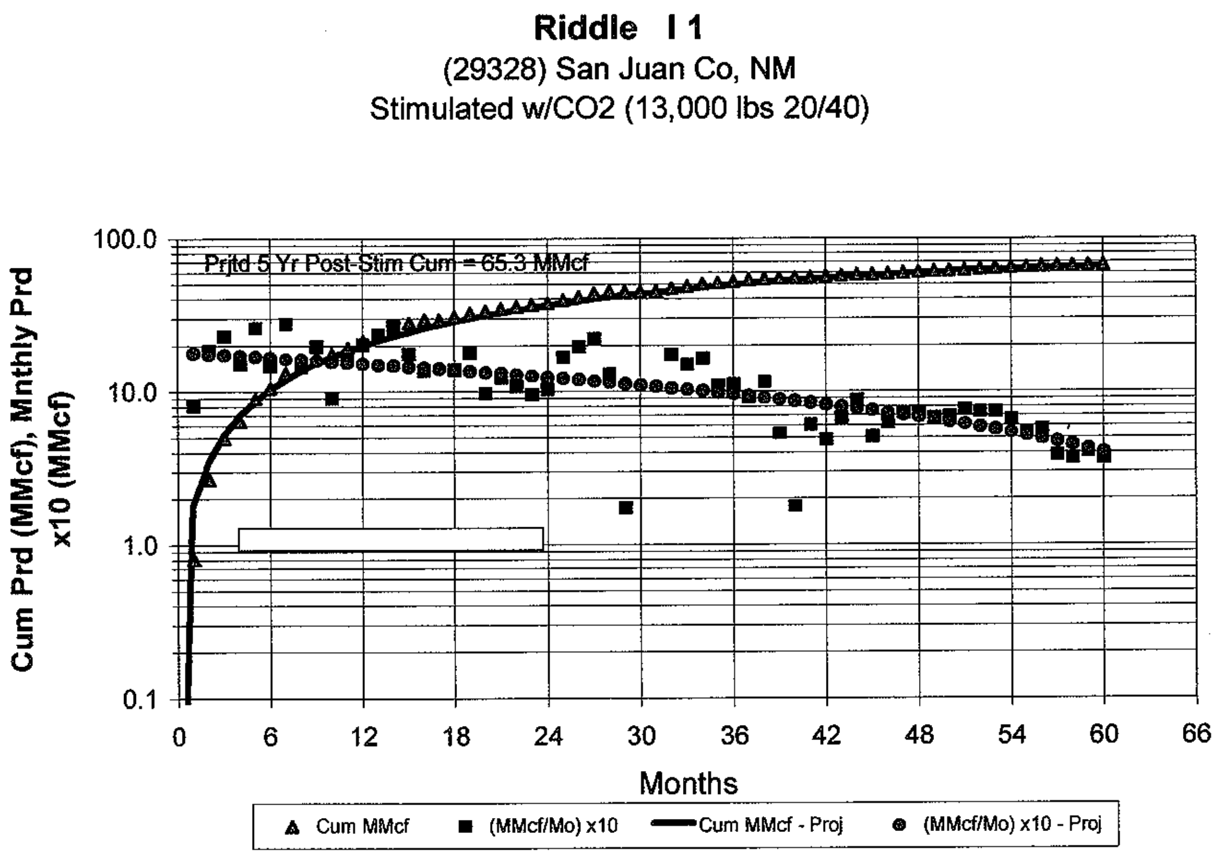
1. Florance GCL 1 (29336) -- Candidate Well # 1



2. Florance Q1 (29345) -- Candidate Well #2

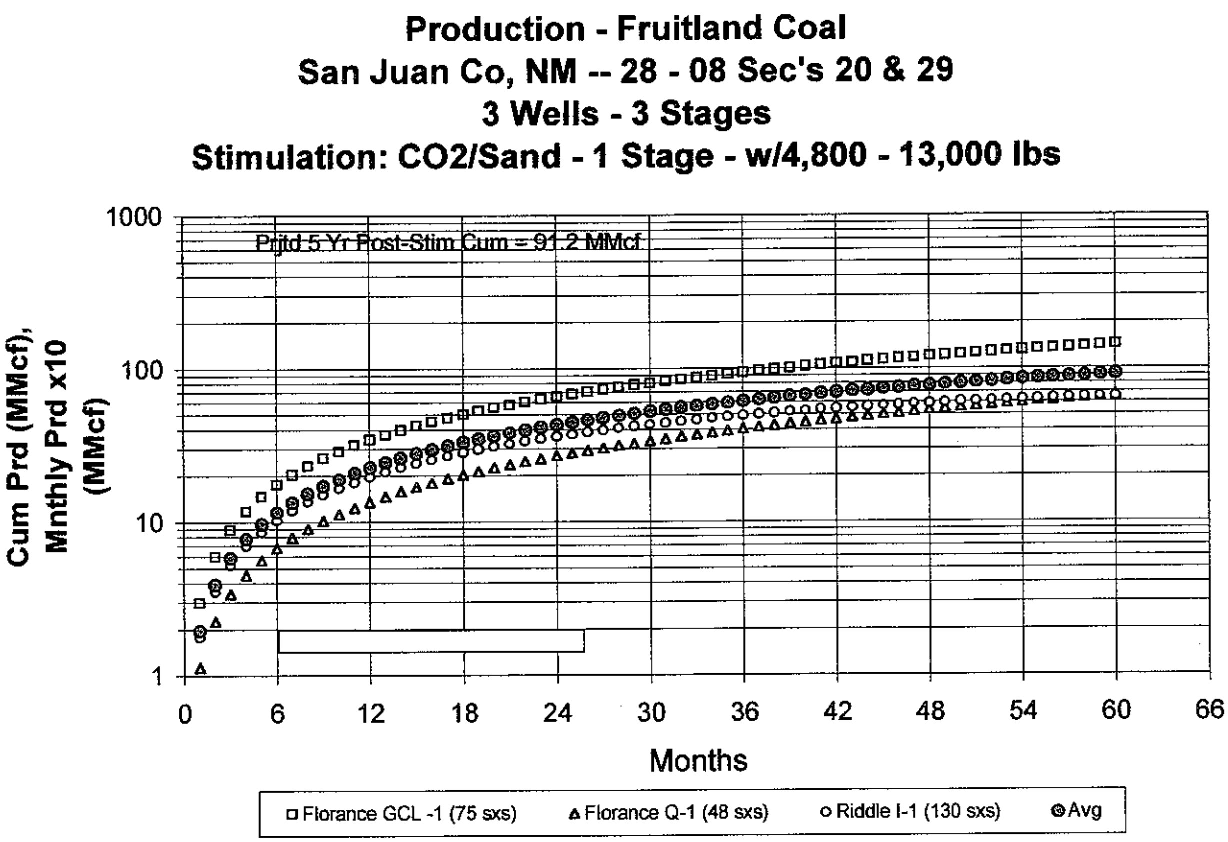


3. Riddle I-1 (29328) -- Candidate Well # 3



B. Production Summary – Candidate Wells

The five year cumulative production from the three Candidate Wells ranged between 65.3 and 141.9 MMcf and averaged 91.3 MMcf.

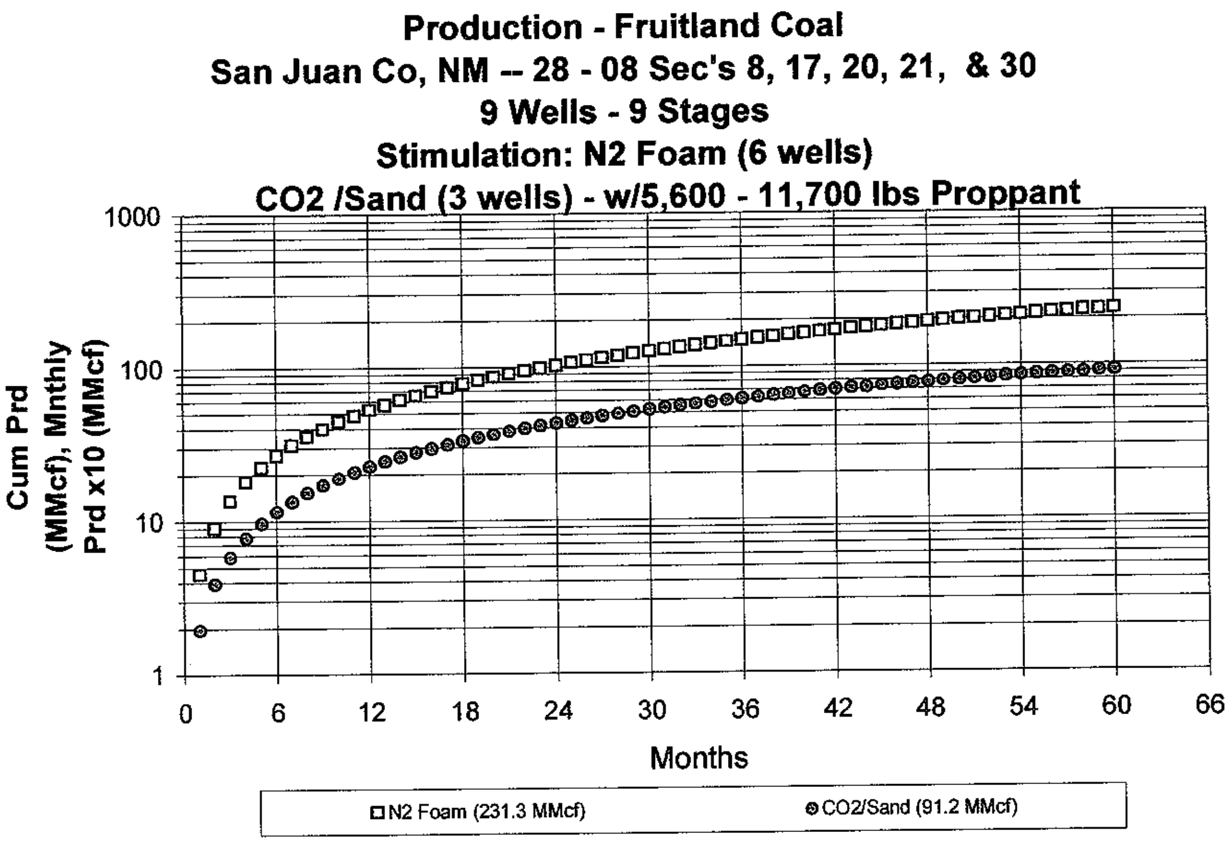


C. Production Comparisons – Control and Candidate Wells

The five year cumulative production volumes from the three Candidate Wells ranged from 65.3 to 141.9 averaging 91.3 MMcf or 39 percent that of the six Control Wells.

Well	Pmt # 30-045- xxxx	Sec	Oper	5 Yr Prod Projt'd	5 Yr Prod Actual MMcf	Prod Mo	Stim Type, Sxs, Bbls
Federal 32-17	28472	17K	Richards	445.2	365.4		
Sharp	21160	08W	SG Intrs	378.7	377.3		
Federal 23-17	28471	17G	Richards	266.6	224.6		
Federal 42-16	28337	21H	Richards	199.8	187.6		
Florance GCL 1	29336	20	BP	141.9	138.7		CO_2 75,227
Federal 28-08-30	28863	30	SG Intrs	81.8	52.7		
Florance Q1	29345	29	BP	66.6	62.4		CO_2 48, 249
Riddle I-1	29328	20	BP	65.3	67.1		CO_2 130, 513
Grambling A	21041	21H	Brlngtn	15.6	3.4	8	

These poor responses from the wells stimulated with the CO_2/sand process are unquestionably related to a number of factors regarding the formation characteristics of permeability and pressure, but to a larger extent to the reduced proppant volumes placed by the liquid-free treatments.



D. Conclusions

1. The projected five year cumulative production ranged from the three Candidate Wells ranged from 65.3 to 141.9 MMcf and averaged 91.3 MMcf while that from the six Control Wells ranged between 15.6 and 445.2 MMcf averaging 231.3 MMcf or 2.5 times that from the wells.

2. These poor responses from the wells stimulated with the CO_2/sand process are unquestionably related to a number of factors regarding the formation characteristics of permeability, and pressure, but to a larger extent to the reduced proppant volumes placed by the liquid-free treatments

XIX. COSTS

A. Projected

The projected costs for stimulating these wells with 120 tons of liquid CO_2 and 40,320 pounds of sand were:

Wells	3	4
Totals	$178,340	$236,200

And, DOE's 50% obligation would be:

	$ 89,170	$118,100

B. Actual

The actual costs for the CO_2/sand stimulations were:

01/22/96 Cost Summary Page 1 of 1

Number	Riddle I-1	Florance GCL #1	Florance Q-1	
Pumping ($)(UWS)	19,660	19,139	16,791	
N2 (HES)	1,695	3,632	2,044	
Sand (HES)	2,046	891	705	
Misc				
	23,401	23,661	19,540	66,603
CO2 (BOC)	6,654	7,447	8,186	
CO2-Portables (BOC)	1,200	1,200	1,200	
Mob (BOC)	2,000	2,000	2,000	
Blender (UWS)	6,000	6,000	6,000	
Tube Trailer (UWS)	5,500	5,500	5,500	
	21,354	22,147	22,886	66,386
Mob,Per Diem (UWS)	2,080	9,600		
Trucking				
Mob,Per Diem (UWS)		2,840		
Misc				
	2,080	12,440	0	14,520
Total	46,835	58,248	42,426	147,509

XX. CONCLUSIONS

A. The production from the Candidate Wells was disappointingly low:

The projected five year cumulative production ranged from the three Candidate Wells ranged from 65.3 to 141.9 MMcf and averaged 91.3 MMcf while that from the six Control Wells ranged between 15.6 and 445.2 MMcf averaging 231.3 MMcf or 2.5 times that from the wells stimulated with the liquid CO_2/sand process.

B. These poor responses from the wells stimulated with the CO_2/sand process are unquestionably related to a number of factors regarding the formation characteristics of permeability, and pressure, but to a larger extent to the reduced proppant volumes placed by the liquid-free treatments.

C. The placed proppant volumes with the CO_2/sand process were much lower than the design volumes:

The proppant volumes placed were much less than the design and ranged from 4,800 to 13,000 pounds and averaged 8,433 lbs or approximately three percent (3%) of that placed in conventional treatments.

The actual volumes placed in zone were:

Well	Pumped (K lbs)	Removed from well (K lbs)	Net in zone (K lbs)
Florance GCL-1	9,800	2,300	7,500
Florance Q-1	6,200	1,400	4,800
Riddle I-1	15,200	2,200	13,000

D. The ability to place the design quantities was obviously limited by

1. Number of perforations
Amoco's practices included utilizing a large number of perforations which in the three Candidate Wells ranged from 200 to 316 over intervals of 120 to 180 feet.. This large number significantly reduced the transport velocity.

Typically 30 perforations are used with the CO_2/sand treatments.

Because of the low viscosity of the CO_2 of approximately 0.1 centipoise (cp), as compared to the N_2 foam with a viscosity of 300 to 500 cp combined with the drastically reduced transport velocity rendered impossible the ability to transport proppant with the CO_2.

2. High leak off rates into the formation.

High leak off rates were known to exist because of the very rapid reduction in wellhead pressure at the termination of the pumping operation. This pressure reduction from 1,200 to 1,600 to 400 psi within a few seconds is greater than the friction pressure and reveals this high leak off rate characteristic of the coal.

E. The benefit of the 20 barrel, 0.5 ppg "slug" of sand in the middle of the pad is significant.

A "pillar" type frac where the sand laden volumes are interspersed with clean CO_2 volumes to provide additional pad volumes for previously uninitiated fractures should be considered.

F. The sand concentration throughout the majority of the treatment should be maintained at 1.0 ppg or less, excepting possibly at the end of the treatment.

G. Consideration should be given to pumping treatments with larger CO_2 volumes at reduced sand concentrations. Because the CO_2 is non-damaging, there would be no fluid retention penalty with the larger volume

H. There was communication between the three Candidate Wells and nearby wells completed in different formations. There was communication between the Candidate Wells which were completed in the Fruitland Coals with nearby (50 feet) wells which were completed in the underlying Pictured Cliff sandstone. There were increases in production and casing pressure recorded in the pumping of the treatments in all three of the Candidate Wells.

I. The costs for the CO_2/sand stimulations (3 wells - 3 stages) was \$147,509 or \$49,170 per stage.

J. The treatments are summarized:

	Sand (lbs)		Max Tr Press	Avg Rate	Sand Conc (lb/gal)	
Well	Pumped	In-Zone	Psi	BPM	Max	Avg
Florance GCL-1	9,800	7,500	3,576	55.8	2.5	1.6
Florance Q-1	6,200	4,800	4,100	55.8	1.9	1.5
Riddle I-1	15,200	13,000	4,702	50.0	1.9	0.8

This concludes the project effort for the demonstrations of the liquid CO_2/sand stimulations in 3 wells (3 stages) which were operated by Amoco (now BP) and completed in the Fruitland Coal in the San Juan Basin. The Three Candidate Wells are situated in San Juan Co, New Mexico in the Type III area. The conclusions indicate that, because of the inability to place adequate proppant volumes, the results are economically unattractive, and that there is little likelihood of practically placing increased proppant volumes.

2 of 2

FIELD TESTING & OPTIMIZATION OF CO_2/SAND FRACTURING TECHNOLOGY
Group #5 -- Phillips Co, Montana -- July 1998 -- Single Stage Treatments -- WBI

Final Report

By
RAYMOND L. MAZZA

Period of Performance
October 1, 1994 - November 30, 2004

Worked Performed Under Contract No.: DE-AC21-94MC31199
"Field Testing & Optimization of CO_2/Sand Fracturing Technology"

For:
U. S. Department of Energy
National Energy Technology Laboratory
Morgantown, West Virginia

By
Petroleum Consulting Services
Canton, Ohio

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ABSTRACT

Three candidate wells located in Phillips County, Montana were stimulated under the subject contract with the CO_2/sand stimulation process in July 1998. The wells are situated in the Bowdoin Dome and produce from the Upper Cretaceous Phillips sand at a depth of approximately 1,100 feet. The wells are operated by WBI and are typically stimulated with Nitrogen (N_2) foam containing 40,000 lbs of 12/20 proppant, and have Estimated Ultimate Recoverable reserves (EUR's) ranging from 175 to 400 MMcf, and produce no water or other liquids. There is a period of reduced production rate immediately following the stimulation which was believed to be a result of the retention of the spent stimulation liquids thereby supporting the potential benefit of the liquid-free CO_2/sand. Additionally, the maximum size of the CO_2/sand treatments is the same as that conventionally used, 40,000 lbs, which would complement the comparison of the liquid-free treatments with those conventionally used.

There were eight nearby control wells which were used to compare the production results from the candidate wells. The treatments were successfully executed and utilized 20/40 proppant in a cost-shared demonstration with WBI. The production results were disappointing in that they were essentially the same as those from conventional stimulations. There is a suspicion that the use of the smaller 20/40 proppant may serve as an impediment as it has been demonstrated that the conventional N_2 foam stimulations result in greater production rates when the larger 12/20 proppant is used then when 20/40 is employed. The basis for this concern is contained within.

The cost of the conventional stimulations is $18,500 and the cost of the CO_2/sand stimulations averaged $53,957 which would require an increase in production rate of 2.9 times.

I. ABSTRACT

Three candidate wells located in Phillips County, Montana were stimulated under the subject contract with the CO_2/sand stimulation process in July 1998. The wells are situated in the Bowdoin Dome and produce from the Upper Cretaceous Phillips sand at a depth of approximately 1,100 feet. The wells are operated by WBI and are typically stimulated with Nitrogen (N_2) foam containing 40,000 lbs of 12/20 proppant, and have Estimated Ultimate Recoverable reserves (EUR's) ranging from 175 to 400 MMcf, and produce no water or other liquids. There is a period of reduced production rate immediately following the stimulation which was believed to be a result of the retention of the spent stimulation liquids thereby supporting the potential benefit of the liquid-free CO_2/sand. Additionally, the maximum size of the CO_2/sand treatments is the same as that conventionally used, 40,000 lbs, which would complement the comparison of the liquid-free treatments with those conventionally used.

There were eight nearby control wells which were used to compare the production results from the candidate wells. The treatments were successfully executed and utilized 20/40 proppant in a cost-shared demonstration with WBI. The production results were disappointing in that they were essentially the same as those from conventional stimulations. There is a suspicion that the use of the smaller 20/40 proppant may serve as an impediment as it has been demonstrated that the conventional N_2 foam stimulations result in greater production rates when the larger 12/20 proppant is used then when 20/40 is employed. The basis for this concern is contained within.

The cost of the conventional stimulations is $18,500 and the cost of the CO_2/sand stimulations averaged $53,957 which would require an increase in production rate of 2.9 times.

II. INTRODUCTION

The fourth group of wells to be treated are situated within the Williston Basin on the Bowdoin Dome, a basement driven pop up event in north-central Montana. Three candidate wells in Phillips County near the town of Saco were selected on the basis production projections from conventionally stimulated offset control wells and, then they were hydraulically fractured with CO_2/sand in July, 1998 . Approximately 40,000 pounds of 20/40 sand proppant, the maximum quantity was placed in two and 38,600 lbs in the third.

The wells in the test area produce from the Phillips Sandstone, a low-pressure, nearly dry-gas formation which produces an immeasurable quantity of water primarily as a vapor. There is no water present in the surface facilities. They generally have estimated ultimate recoverable reserves (EUR's) ranging from 175 to 400 MMcf and are typically stimulated with nitrogen (N_2) Foam and 40,000 lbs of sand proppant.

On the basis of the time required to reach maximum production rates following the foam stimulations, although not unreasonable, the Phillips was suspected to be damaged by the stimulation liquids. Because of this lengthened clean up behavior and the suspicion that the spent stimulation liquids were the root cause of the suspected damage, it was agreed that the utilization of the liquid-free CO_2/sand stimulation could potentially provide a significant benefit and that production rate increases could possibly result.

The CO_2/sand stimulations utilize approximately the same proppant volume and because no spent stimulation liquids remain were considered to be undamaged by the retained fracturing liquids. It was anticipated that because of the similar proppant quantity of the two treatment types that the length of the induced fracture should be approximately the same. The hydraulic fractures generated with the CO_2/sand process were expected to be more productive primarily because of the similar lengths and the reduced impediment to gas flow.

The results have been disappointing in that the twenty-four month cumulative gas production from the three candidate wells stimulated with CO_2/sand have not out performed the seven control wells which were stimulated with N_2 Foam nor have they been any worse. The cumulative productions are essentially identical.

Based on observations of the production behaviors, a potential explanation of this unexpected response is suspicioned to be a consequence of the smaller size proppant used in the CO_2/sand stimulations. The three candidate wells utilized 20/40 mesh and the control wells employed larger 12/20 size proppant. Of interest is the observation that the cumulative production from the wells with the larger proppant have, as is generally the case, significant variations while that from the wells with the smaller size proppant do not. Their performance is essentially identical and without variation. This is a unique and unexpected response and there exists a reasonable anticipation that the gas production rates from the wells which are stimulated with the liquid-free CO_2/sand process would be improved if a larger proppant size were utilized. This recommendation is not without risk. It should be recognized that while there was no difficulty encountered in placing the smaller and conventionally used proppant size with the less viscous CO_2, it may be found to be difficult with the larger proppant. Conversations with experienced operations personnel very familiar with this technology have indicated that larger 12/20 proppant, has been successfully placed in the same formations in southern Alberta. Therefore, this potential for stimulating wells in the Bowdoin Field with CO_2 and the larger size proppant exists

III. BACKGROUND

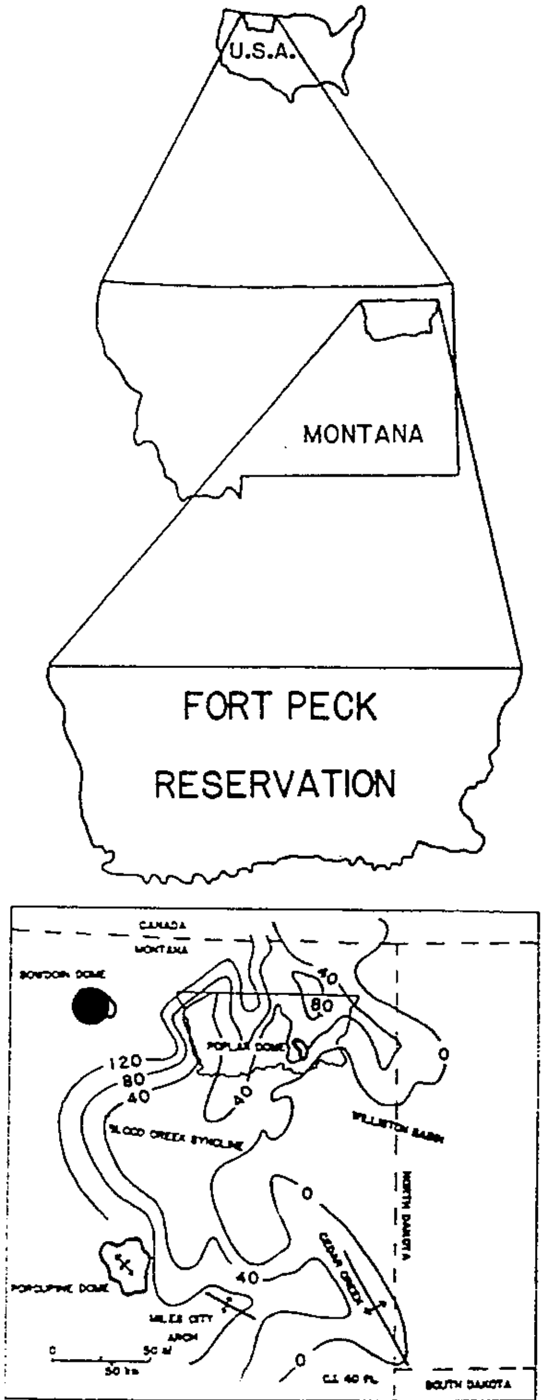
Fidelity Exploration & Production Co (formerly Williston Basin Interstate Pipeline Company (WBI) - subsidiaries of MDU Resources) is the operator of a large number of wells in the Bowdoin Dome in Phillips County, Montana. These wells produce from the Phillips Sandstone, a shallow (1,200 ft), lower pressure (300 psi) Upper Cretaceous formation that was suspected of being damaged by conventional N_2 Foam stimulation procedures. WBI was both interested in determining if a production improvement would result from the CO_2/sand stimulation process, and in participating with the DOE in a cost-shared demonstration and evaluation of this technology.

The production response characteristics of this formation and offering were considered to be a viable opportunity to evaluate the benefits of the CO_2/sand stimulation technology, primarily because of the absence of produced liquids of significance from the Phillips Sandstone and, also because the conventional treatments as well as the CO_2/sand process utilize the same quantity proppant, 40,000 pounds.

It had been estimated that 81% of the spent stimulation liquids remain in the Phillips and that these liquids could be damaging the reservoir and reducing the gas producing potential.

The Bowdoin Dome is within the Williston Basin and is centered in Phillips County, Montana, approximately 50 miles west of the Ft. Peck Indian Reservation (Map 1). It has been producing natural gas in commercial quantities since the 1920's from several Upper Cretaceous age formations, the Lower Phillips Sandstone being the deepest. It along with the Upper Phillips are the producing formations in the three candidate wells which are the focus of this demonstration.

Map 1

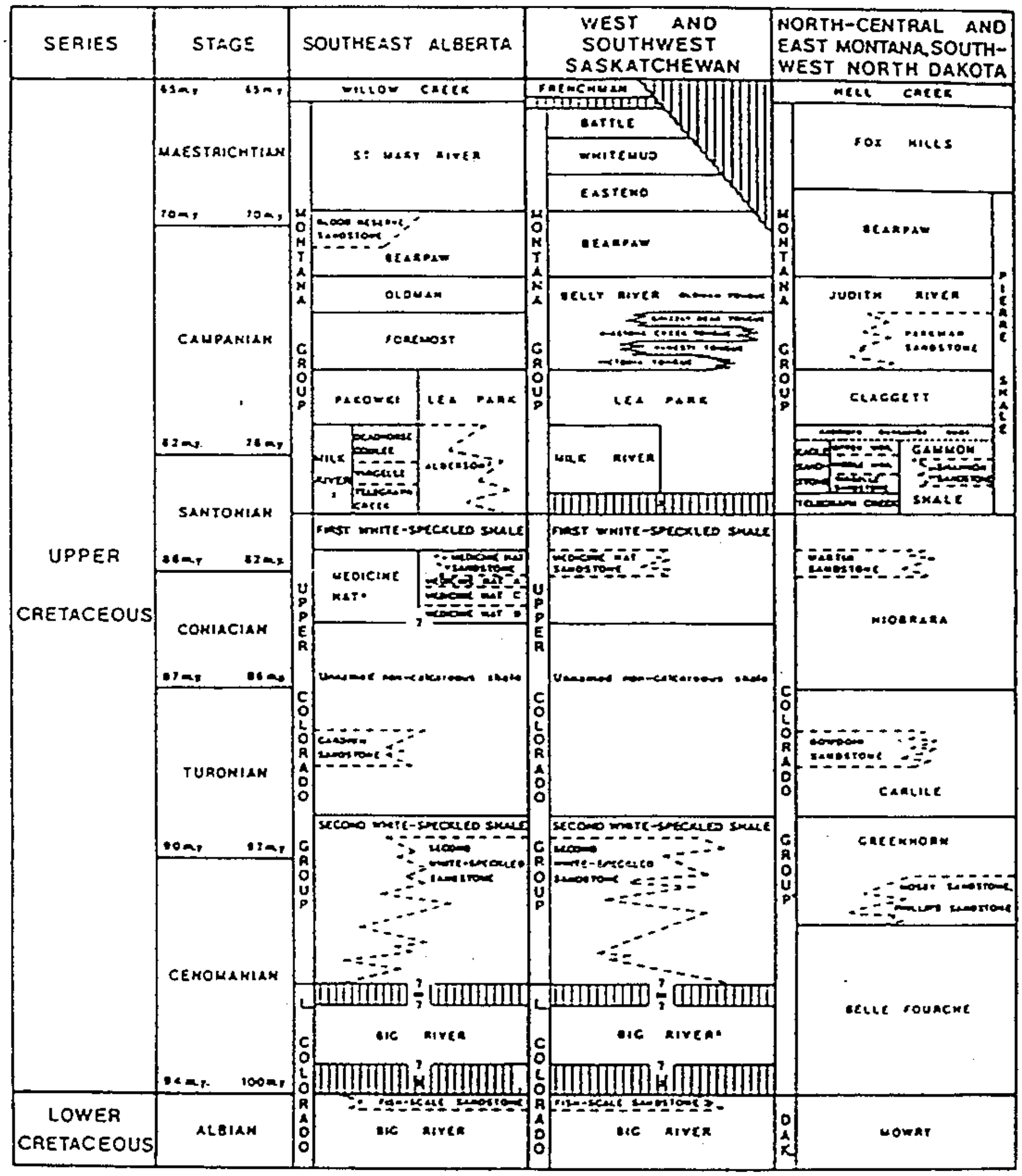

U.S.A.
MONTANA
FORT PECK
RESERVATION
CANADA
MONTANA
POPLAR DOME
WILLISTON BASIN
NORTH DAKOTA
CEDAR CREEK
MILES CITY
ARCH
SOUTH DAKOTA

It should be pointed out that in this demonstration, that for the first time, only the Upper Phillips Sandstone was perforated in all of the wells drilled in 1998, 99, and 2000 programs. This decision was based on the results of a tracer survey study which indicated a benefit to this strategy. A discussion of the evaluation and conclusions follows in the PERFORATION STRATEGY section (9).

IV. GEOLOGY

The Phillips Sandstone is within the Greenhorn sequence of the Colorado group and can be considered as a traditional sand reservoir, there are two members, both an Upper and a Lower Phillips Sandstone. The shallower Bowdoin Sandstone (Carlile sequence) can contain as many as three benches and is also productive. It is overlain by the Martin Sandstone, which is a zone contained within the Niobrara sequence (Figure 1). The Niobrara is rich in organic materials and is self-sourcing. It can be analogized to "a big pile of mud with silt and sand stringers" and is a likely source of the gas contained in the Bowdoin and Phillips sands.

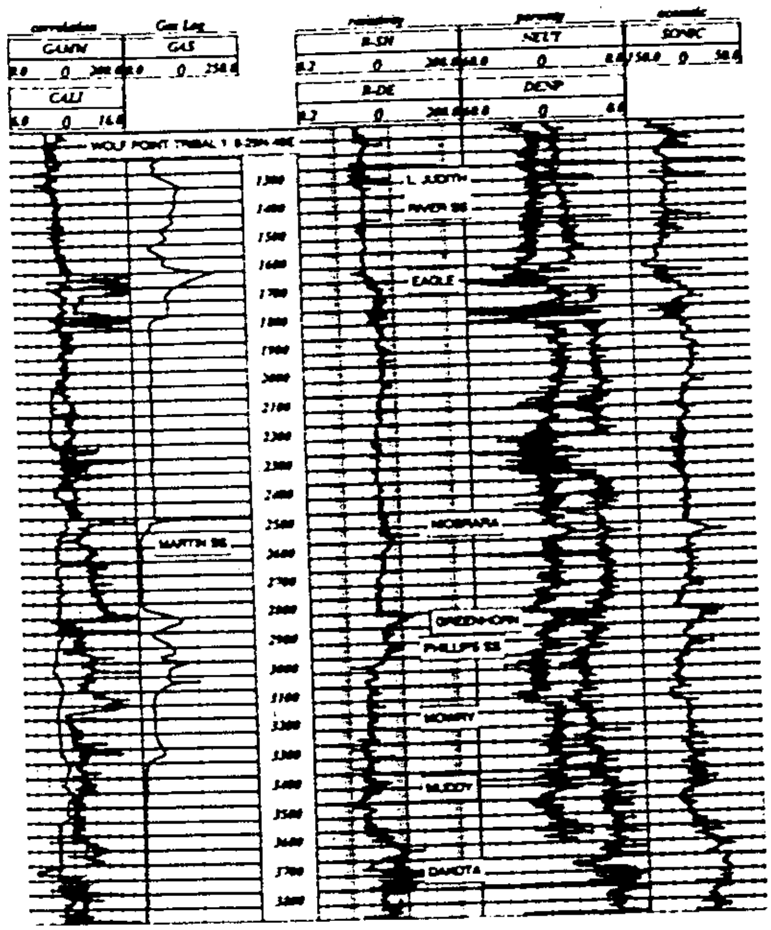
Figure 1


SERIES
STAGE
SOUTHEAST ALBERTA
WEST AND SOUTHWEST SASKATCHEWAN
NORTH-CENTRAL AND EAST MONTANA, SOUTH-WEST NORTH DAKOTA
UPPER CRETACEOUS
LOWER CRETACEOUS
MAESTRICHTIAN
CAMPANIAN
SANTONIAN
CONIACIAN
TURONIAN
CENOMANIAN
ALBIAN
WILLOW CREEK
ST MARY RIVER
BEARPAW
OLDMAN
FOREMOST
PAKOWKI
LEA PARK
MILK RIVER
FIRST WHITE-SPECKLED SHALE
MEDICINE HAT
Unnamed non-calcareous shale
SECOND WHITE-SPECKLED SHALE
BIG RIVER
FRENCHMAN
BATTLE
WHITEMUD
EASTEND
BELLY RIVER
MONTANA GROUP
UPPER COLORADO GROUP
LOWER COLORADO
HELL CREEK
FOX HILLS
JUDITH RIVER
CLAGGETT
GAMMON SHALE
NIOBRARA
CARLILE
GREENHORN
BELLE FOURCHE
MOWRY
PIERRE SHALE
DAKOTA

A. <u>Stratigraphy</u>

The Phillips has a repeating coarsening upward sequence and is readily identifiable on electric logs (Figure 2). At least two of the cycles are present and productive. The cleaner portion of the cycle is shown to consist of very fine quartzose sandstone with laminae of clay. The upper cycle generally has the larger porosity of the two.

Figure 2



V. RESERVOIR

The Phillips Sands constitute a volumetric drive reservoir with minimal water production. The in-place gas reserves range from 30 to 60 Mcf per acre foot which results in calculated producible reserves within the test area ranging between 175 and 400 MMcf per well. The annual decline rates range from 15 to 20 percent following a two to three month period of higher rate "flush production". Typical water production rates are as much as, but generally less than one barrel per month. The water is discharged into and quickly evaporates from an earthen pit. The majority of the pits show little if any indication of ever containing produced water.

Within the test area the Phillips Sandstone lies at depths ranging from 1100 to 1200 feet. The thickness varies from 80 to 105 feet, the porosities range from 18 to 21 percent and the permeability ranges from 0.5 to 5.0 md. Copies of the electric logs are attached.

The formation water salinity can range from 100 to 10,000 mg/l. Within WBI's operations the salinities range from 800 to 8,000 mg/l. And, it is not uncommon for offset wells to have largely different salinities, these differences do not appear to be related to the gas production. Perhaps the evaporation of the minimal water production prior to obtaining the water samples may be an explanation for the large variations in the measured salinity.

A. Reservoir Pressure and Temperature

Generally the reservoir pressure and temperature are 300 psi and 70° F and the pipeline pressure is approximately 100 psi.

Within the test area the reservoir pressure, as measured by shut-in wellhead pressures ranges from 287 to 396 psi (Figure 3).

Figure 3

PETROLEUM CONSULTING SERVICES
P O BOX 35833
CANTON, OHIO 44735-5833
(330) 499-3823

RESERVOIR INFORMATION

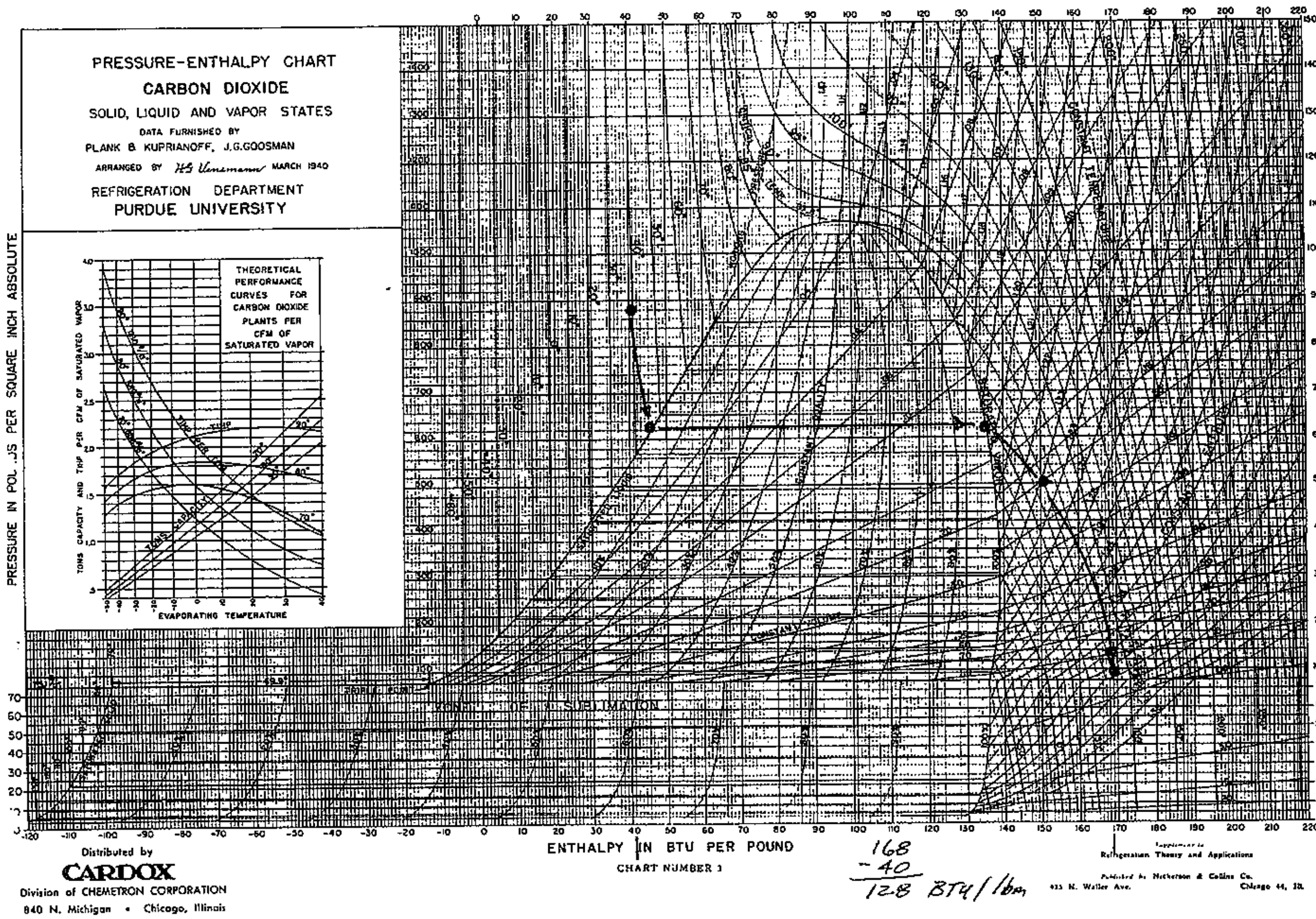
OPERATOR: WILLISTON BASIN INTERSTATE PIPELINE 05/11/98
FIELD: BOWDOIN DOME TARGET: PHILLIPS SAND CO/ST: PHILLIPS/MT

ABANDONMENT PRESSURE(PSIG): 100

WELL	COMP	ELEV SURF (GLM)	ELEV KB (KBM)	TOTAL DEPTH (KBM)	DEPTH TOP PHILPS (KBM)	ELEV SUB SEA (FT)	DEPT BOT PHILPS (KBM)	THICK (FT)	POR (PCT)	RESVR PRESS (PSIG)	IN PL RESR (MMC /A)	RCVBL RSRVS (MMCF /A)	EUR ESTMT (MMCF	DRNGE AREA (ACRES)	MAX TEMP (F)	GOTHRML GRAD [SURF=60 (D/100FT)
972	Sep-94	2308	2313	1280	1018	1294	1086	67	18.6%	396	15	11	200	17	97	2.9
973	Sep-94	2341	2346	1280	1022	1324	1110	88	20.0%	308	17	12	350	30	74	1.1
974	Sep-94	2353	2358	1267	1046	1312	1126	80	20.4%	293	15	10	300	30	73	1.0
976	Sep-94	2212	2217	1204	900	1317	988	88	20.4%	287	16	11	250	23	72	1.0
990	Sep-95	2271	2277	1225	946	1331	1036	90	21.3%	??	??	??	300	??	82	1.8
991	Sep-95	2274	2280	1225	955	1325	1050	95	21.0%	??	??	??	275	??	83	1.9
997	Jul-96	2382	2389	1250	1076	1313	1181	105	20.4%	333	22	16	175	11	72	1.0
1000	Sep-95	2258	2264	1250	928	1336	1018	90	20.1%	??	??	??	??	??	86	2.1
1002	Sep-95	2306	2312	1250	1008	1304	1092	84	20.1%	??	??	??	??	??	84	1.9

The CO_2 will readily vaporize under these conditions, approximately 25.6MM BTUs per 100 tons of liquid CO_2 are required (Figure 4).

Figure 4



B. Gas Properties

The gas composition is 93% methane, 6% nitrogen, and 1% other gases, which results in a biogenic gas with a calorific value of 950 BTU per cubic foot.

C. Sensitivity to Stimulation Liquids

The control wells were stimulated with 65 quality nitrogen Foam. Because of the liquid sensitive nature, lower pressure of these formations, and the reduced volume of the stimulation load water returned, which has been estimated to be 81%, it was suspected that the advantages of a liquid-free stimulation could result in an economic benefit.

D. Estimated Ultimate Gas Recovery (EUR) & Production - Months 2-13

The oldest control wells had, at the time of the test preparation, been producing for three years and were projected to have EURs ranging from 175 to 350 MMCF.

It was later observed that both the control and candidate wells stimulated in 1998 would all have lower production rates and consequently reduced EUR's than those of wells which had been drilled prior to 98.

It was also agreed that the success criteria would be to compare the cumulative gas production volumes for producing months two through thirteen. Within the test area the gas productions for months two through thirteen from the eight well control group the ranged between 24.2 and 71.1 MMcf, averaging 57.3 MMcf. However, it was subsequently determined that the production from the wells conventionally stimulated with N_2 foam at the time of the test in 1998 also had significantly lower production rates. The production for months two through thirteen from the seven new wells stimulated with N_2 foam in July 1998 ranged from 16.6 to 54.7 MMcf, averaging 33.1 MMcf. Had this been known at the time, the criteria for success would have been reduced.

VI. IS THE PROPOSED RESERVOIR LIKELY TO BENEFIT FROM THE CO_2/SAND TECHNOLOGY?

Because the CO_2/sand stimulation utilizes CO_2 as the working fluid which is pumped as a liquid and subsequently vaporizes at formation temperature and flows from the reservoir as a gas, no liquid remains behind and the gas can flow from the reservoir unimpeded.

Because of the absence of produced liquids from the Phillips Sandstone in this area, where it had been estimated that 19% of the spent stimulation liquids remain in this "slow to clean up" reservoir and also because of the similarity of the proppant volumes, 40,000 pounds for both the N_2 Foam and the CO_2/sand stimulation types that the reservoir would benefit from the CO_2/sand stimulation.

VII. OPERATOR

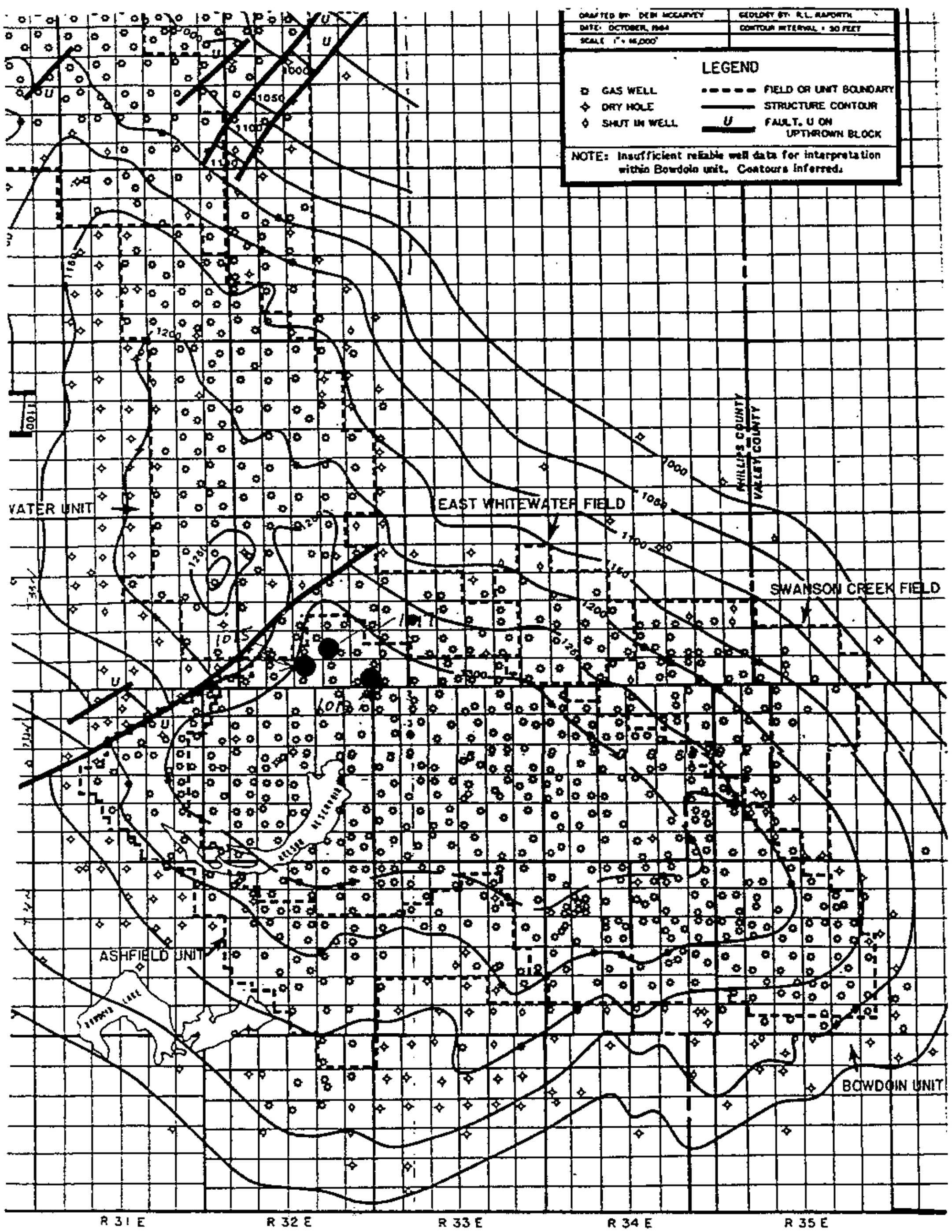
WBI indicated an interest in the process and was fully supportive with the demonstration of the liquid-free stimulation technology. They provided and ensured an excellent test opportunity and were, and are, in a position to derive a significant economic benefit from a successful result. They continue to have an active drilling program and could employ any beneficial results in their upcoming activities.

They requested DOE cost-shared support and agreed to share the production data from both the control and candidate wells for five years.

VIII. TEST AREA

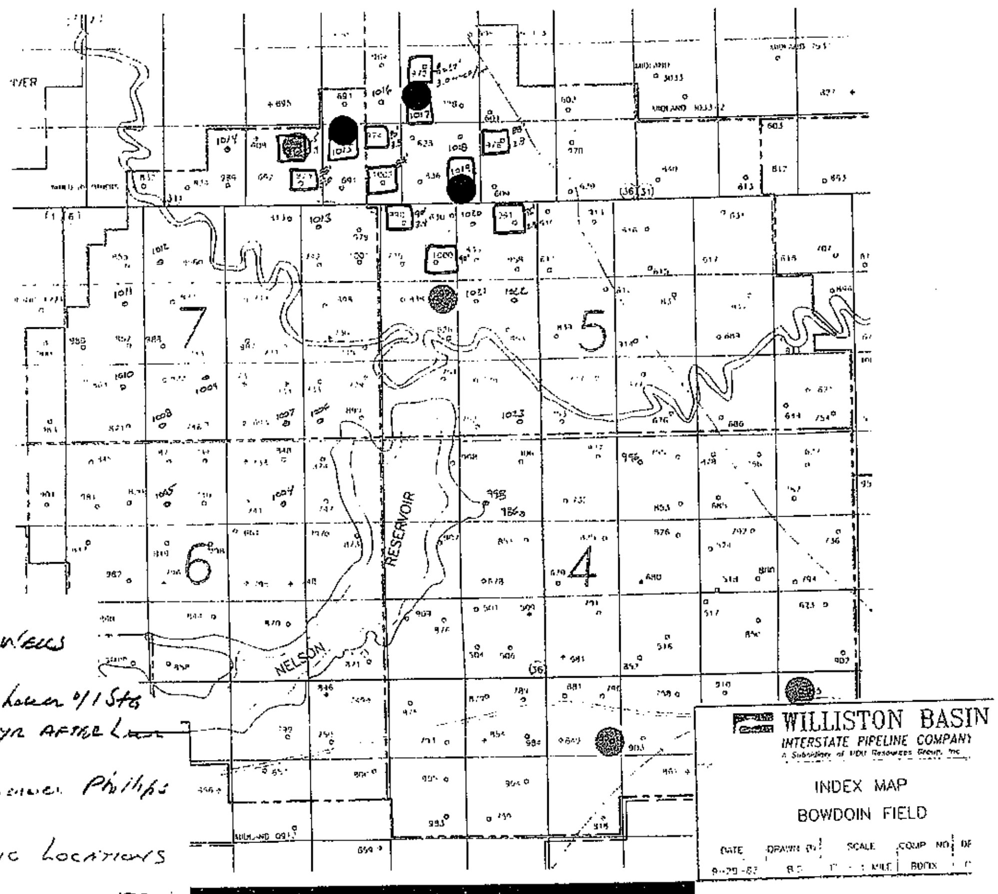
The test area is located in the northern most segments of WBI's Bowdoin Dome drilling boundaries and is approximately rectangular with dimensions of 2-1/2 by 3 miles. It is nine miles northwest of the town of Saco and three miles north of the Nelson reservoir. It includes seven sections within townships 32N and 33N and Range 32E (Map 2).

Map 2


LEGEND
GAS WELL
DRY HOLE
SHUT IN WELL
FIELD OR UNIT BOUNDARY
STRUCTURE CONTOUR
FAULT, U ON UPTHROWN BLOCK
NOTE: Insufficient reliable well data for interpretation within Bowdoin unit. Contours inferred.
EAST WHITEWATER FIELD
SWANSON CREEK FIELD
ASHFIELD UNIT
BOWDOIN UNIT
VATER UNIT
PHILLIPS COUNTY
VALLEY COUNTY
R 31 E
R 32 E
R 33 E
R 34 E
R 35 E

It includes the three candidate wells, #'s 1019, 1020, and 1021, and at the time of the test, sixteen control wells consisting of nine existing wells and seven new wells all of which were stimulated with nitrogen Foam (Map 3).

Map 3



Revised Candidate Wells

783 Fraced upper & lower 1/1 Stg

784 Fraced Upper 1yr After L...

Traced, upper/lower Phillips

o - Current Drilling Locations

- Wells Drilled Since 1994
w/ N_2 Foam Frac's & Individual Measurements

]- Proposed Test Well CO_2 Frac

]- Test Well Offset

A. Candidate Well Selection

The candidate wells were selected on the basis of their representative nature and position within the field, distance from an established reservoir boundary, and their proximity to conventionally stimulated control wells.

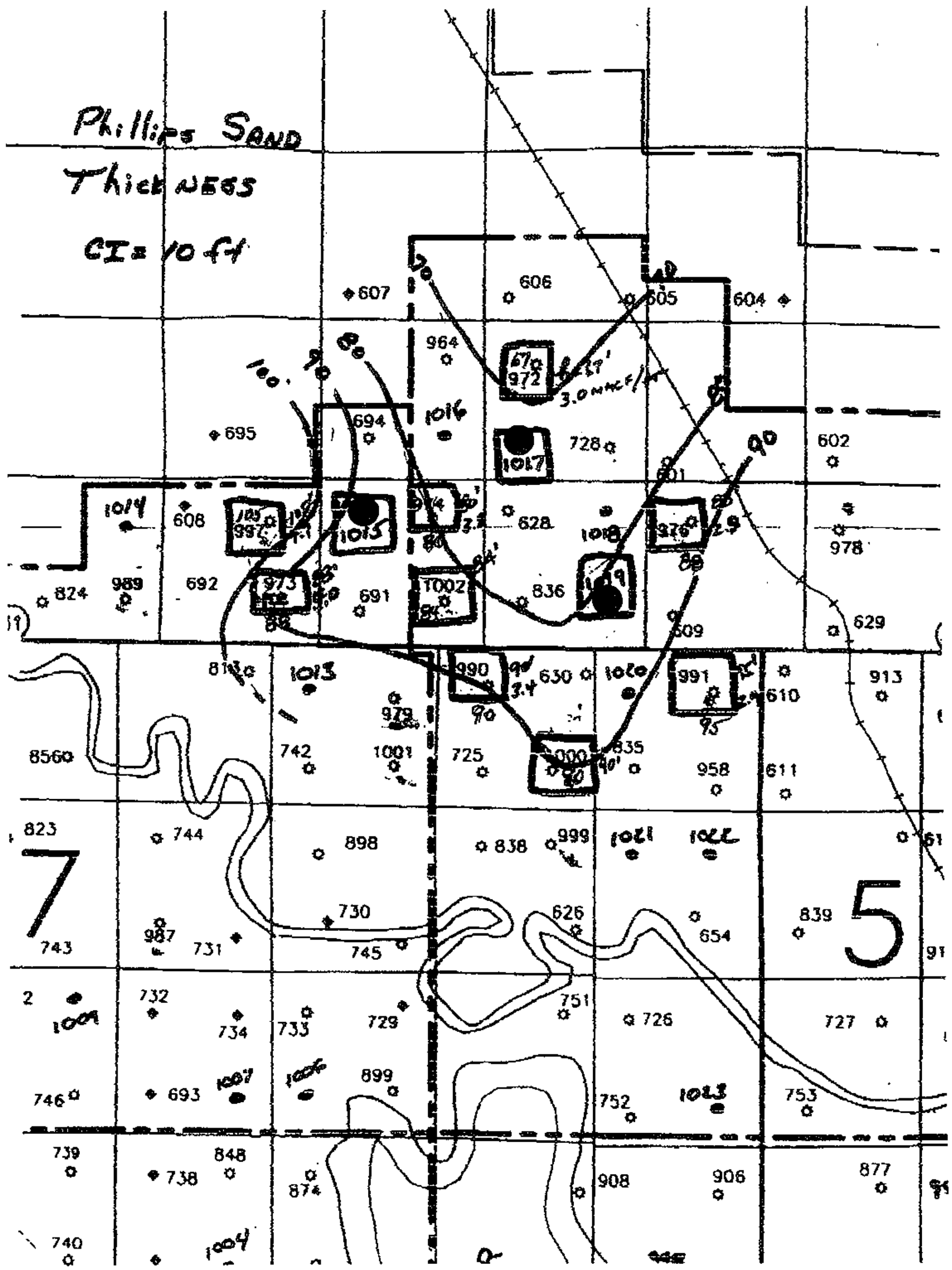
They were selected to provide a reasonable distance from an established dry hole area to the north and, also such that they would be surrounded by representative, commercially viable control wells.

The candidate wells are located 1 to 1-1/2 miles south of the dry hole area, and are positioned such that there are a number of representative wells between the test area and this northern field terminus. This area of uneconomic reserves north of the test area was previously identified and established as a field boundary. The wells drilled north of this boundary (604, 607, 608, and 695) were abandoned as non-commercial. They confirmed the presence northern edge of an up- thrown block and of the presence of a tear fault having approximately 25 feet of vertical displacement (Map 2).

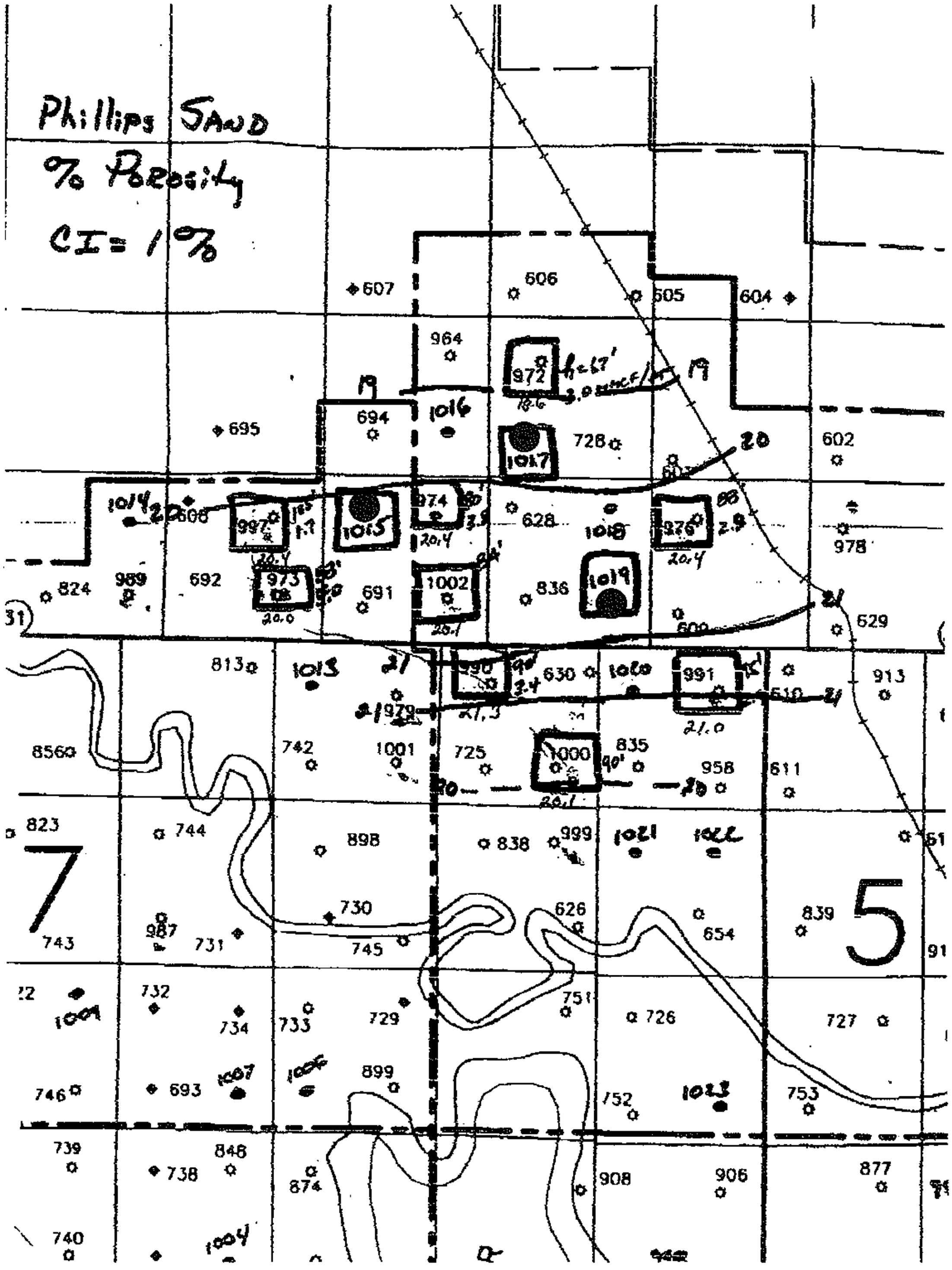
The Phillips in the northernmost group of active wells, 972 has the lowest sub-sea elevation (1924 ft), the thinnest section (67 ft), and a reduced EUR (200 MMcf) and was considered to be indicative of the reduced potential near this northern field boundary.

The initial proposal, Package #5, included three candidate wells, 1015, 1017, and 1019. Contour maps were then constructed from the control well data: the projected sand thickness, porosity, average daily production, and the cumulative production for months two through thirteen (Maps 4-7).

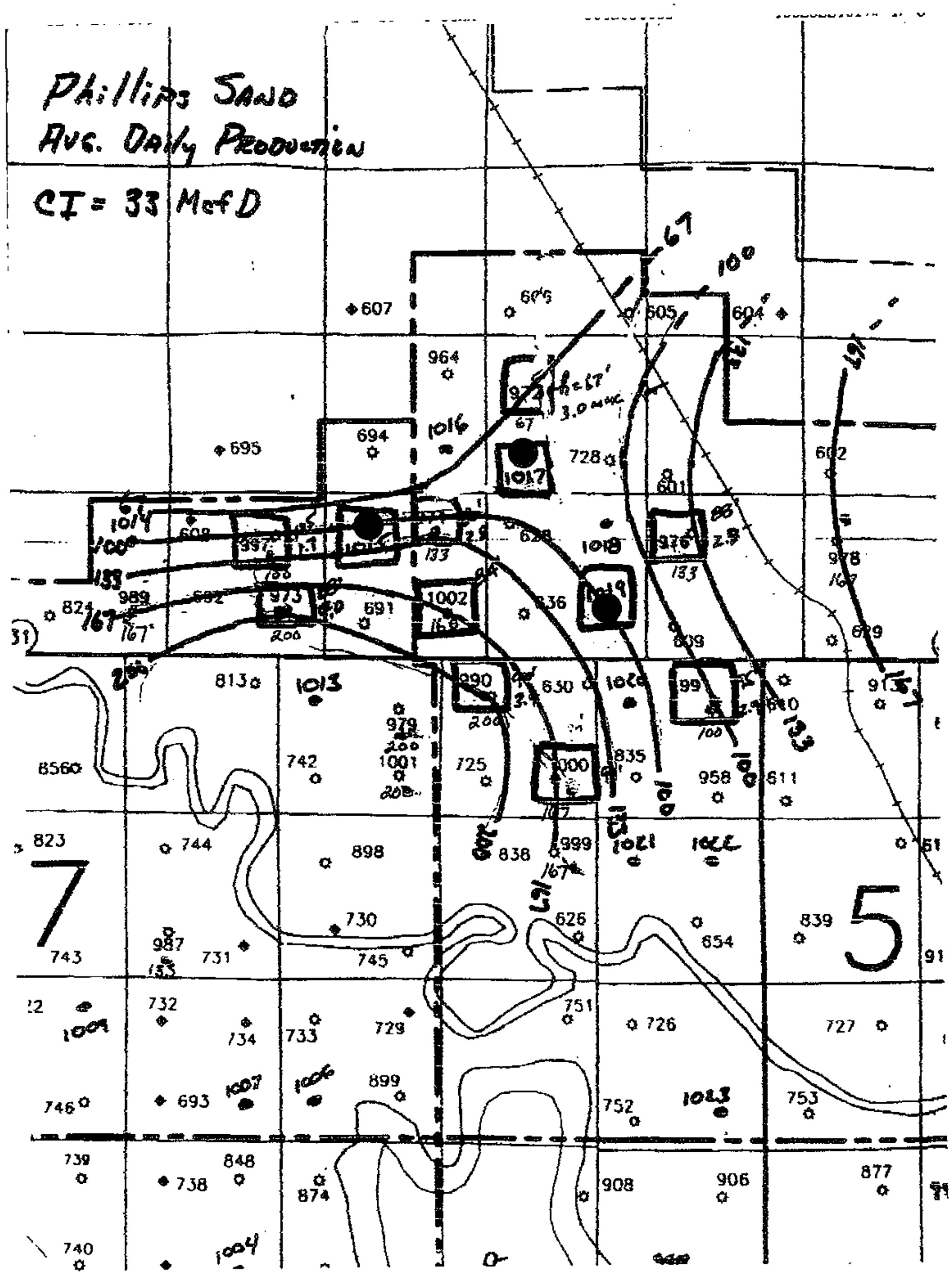
Map 4



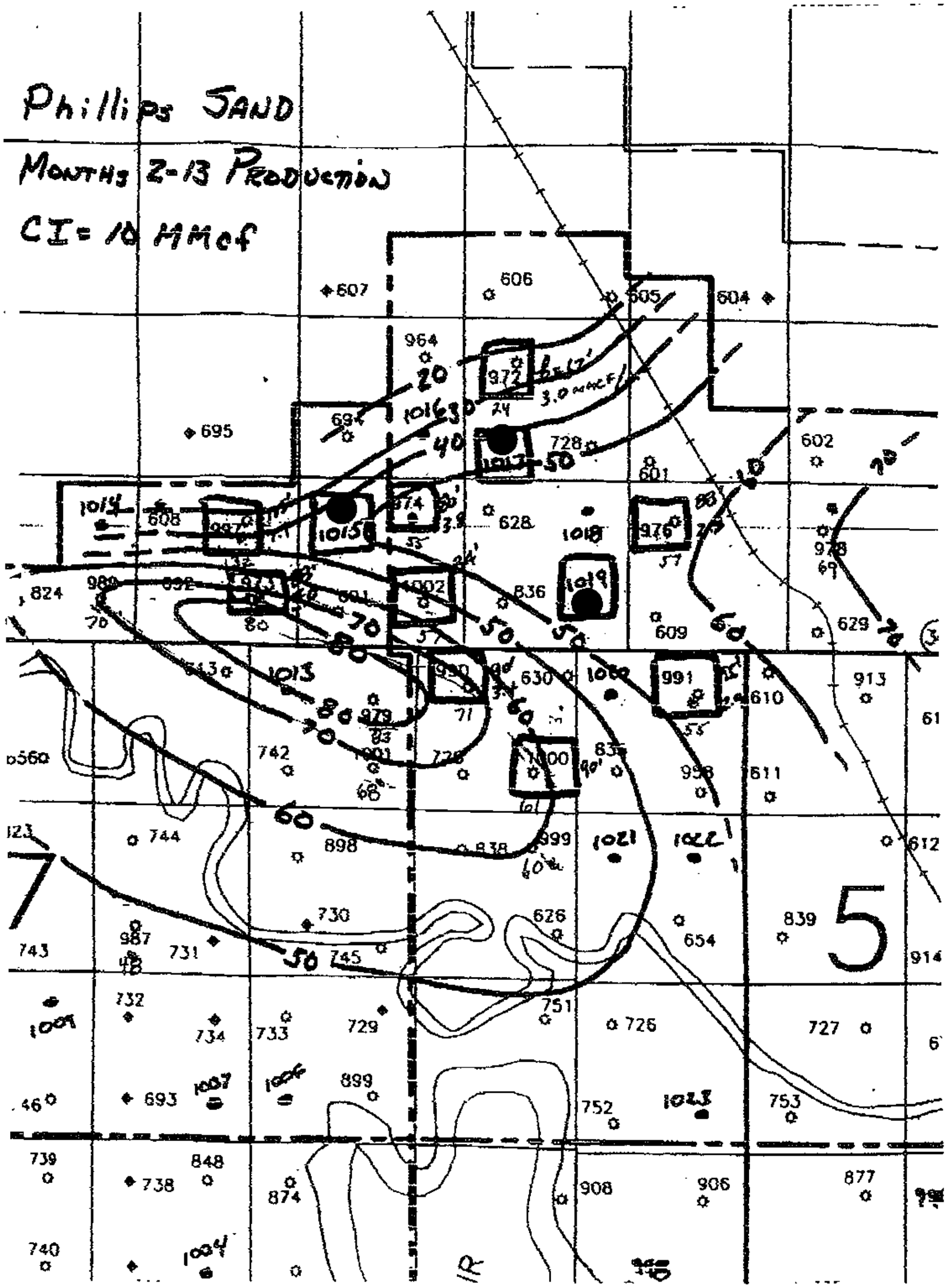
Map 5



Map 6



Map 7



After reviewing these contour maps, two of the wells, 1015 and 1017 were rejected as being influenced by the thinning of the sand, reduced cumulative production, and porosity reduction, presumably resulting from the influence of the tear fault. They were replaced by wells 1020, and 1021. The result being that wells 1019, 1020, and 1021 were chosen as the candidate wells. A revised submittal package, #5A was prepared and submitted to the DOE for consideration.

The projected values for both the rejected and candidate wells were:

Well #:	1015	1017	1019	1020	1021	1022
Status	Rej	Rej	Cand	Cand	Cand	Extra
Sand Thickness (Ft)	88	73	82	90	100	100
Porosity (%)	20.1	19.5	20.7	21.0	19.5	19.5
Avg Daily Prod (Mcf/d)	100	75	100	110	125	90
Cum Prod Mo 2-13 (MMcf)	32	42	54	45	54	45

B. Control Wells

1. Production Review and Projections

The production projections were based on the observations made from the produced volumes from the nearby control wells which were all perforated in both the Upper and Lower Phillips Sand members-Cumulative for Months 2 through 13:

Control Wells (N_2 Foam)								
Existing Wells (Stimulated Prior to 07/98)								
					API #	Cum Prod (MMcf)		
Well #	Twp	Rge	Sec	Quad	25-071-	Month 2	Month 13	Month 2-13
972	33N	32E	27	NW	22267	1.046	25.433	24.387
973	33N	32E	32	SE	22268	1.187	80.759	79.572
974	33N	32E	33	NE	22269	0.874	55.875	55.001
976	33N	32E	35	NW	22272	0.441	56.654	56.213
990	32N	32E	02	NW	22275	12.699	83.790	71.091
991	32N	32E	01	NE	22279	9.158	63.894	54.736
997	33N	32E	32	NE	22287	?????	32.568	32.568
1000	32N	32E	02	SE	22283	10.880	71.401	60.521
1002	33N	32E	33	SE	22288	9.671	66.678	57.007
							Avg (n=8)	57.316

2. Treatment Volume

The typical nitrogen Foam treatment includes 40,000 pounds of 12/20 sand as the proppant.

3. Cost

The cost of typical nitrogen Foam stimulation in July 1998, at the time of the test was $18,500 including nitrogen. The cost was reported earlier as $25,000 which included $5,000 for nitrogen and was initially used to project the required ratio for an economic success.

C. CO_2/Sand Stimulation Treatments

1. Design

a. Proppant Size

The proppant size utilized with the CO_2/sand stimulations was 20/40 which is conventionally used with the lower viscosity of the liquid CO_2. Consideration was given to utilizing 20/40 for the for the first treatment and if the sand placement progressed smoothly, which it did to then utilize the larger 12/20 proppant for the remaining treatment(s).

There was no difficulty encountered in placing the smaller proppant in the first treatment and, as planned, efforts were made to obtain 12/20 proppant which was being stored nearby and at the time being utilized by another service company in the execution of the N_2 Foam stimulations on other WBI wells. Unfortunately, although the proppant was available and dedicated to WBI, the other service company, Halliburton Energy Services would not make it available presumably because the CO_2/sand stimulations were being performed by a competing service company, Canadian Fracmaster.

b. Treatment Volume

The conventional stimulations utilize approximately the same proppant volume as that for a CO_2/sand treatment although of a larger size (12/20 vs 20/40). The similarities of the proppant volumes resulted in a like comparison of the production resulting from the two stimulation types.

It should be noted that upon review and comparison of the production histories that there is a question as to whether the production rates from the CO_2/sand stimulations would have been greater and especially more variable if the larger proppant had been used.

Because the production responses from the three CO_2/sand stimulations lack any variability and are essentially identical, it is suspected that the production is limited by the proppant pack conductivity which is suspicioned to be reduced by the embedment of the smaller diameter proppant into the Phillips Sandstone.

Various stimulation designs were prepared by Canadian Fracmaster and presented to WBI. The result being that the design which included the largest proppant volume was selected.

The proposed design included 44,100 pounds of 20/40 sand proppant and 542 barrels (104 tons) of liquid CO_2 pumped at 38 barrels per minute. A maximum sand concentration of 5 pounds per gallon and a wellhead pressure of 977 psi was projected.

The recommended stimulation design was:

PROPPANT FLUID SCHEDULE					
	Cum	Stage	Proppant	Proppant	Cum
	(bbl)	(bbl)	(ppg)	(lb)	(lb)
Stage					
Hole Fill (Liquid CO_2)	25.0	25.0			
Pad (Liquid CO_2)	190.0	165.0			
Start (20/40 Sand)	220.0	30.0	0.8	1,000	1,000
Increase (20/40 Sand)	260.0	40.0	1.7	2,850	3,850
Increase (20/40 Sand)	410.0	150.0	2.5	15,750	19,600
Increase (20/40 Sand	587.0	177.0	3.3	24,500	44,100
Flush (Liquid CO_2)	606.0	19.0			

TREATMENT FLUID REQUIREMENTS						
	Hole	Pad	Prop	Flush	Bottoms	Total
Liquid CO_2 (bbl)	25.0	165.0	397.0	19.0	189.0	795.0
Nitrogen (SCF)						199,148

D. Treatment Volume Comparison - Conventional vs CO_2/Sand

The treatments typically consist of 18,500 gallons of 65 quality nitrogen Foam which requires approximately 6,500 gallons of water and chemicals. The nitrogen component is pressure dependent and is approximately 75 Mcf. The breakdown pressure is generally 1000 psi and the treatments are generally pumped at 30 barrels per minute at a wellhead pressure of 750 psi. The sand concentration is progressively increased to 12 pounds per gallon at the end of the treatment to completely pack the fractures near the well bore. This procedure has been introduced by Halliburton Energy Services as an outgrowth of a study and has resulted in improved production rates.

IX. STIMULATION CHECK LIST

A stimulation check list was developed early in the selection and test design process to capture the reservoir, production, stimulation, etc. specifics (Figure 5).

Figure 5 (p. 1 of 2)

PETROLEUM CONSULTING SERVICES
(330) 499-3823
(330) 499-2280 (fax)

CO_2\SAND STIMULATION CHECKLIST
p. 1 of 2

Date 05/13/98

Formation:	Phillips Sand	Operator:	Williston Basin Intrst Ppln Co.
Geologic Era:	Upper Cret		P. O. Box 131
County:	Phillips		Glendive, MT 59330
State:	Montana		
Field:	Bowdoin Dome	POC:	Dennis Zander (406) 359-7200
Basin	Williston		Fax (406) 359-7273

1. Reservoir	
a. Depth (ft):	1100
b. Thickness (ft):	100
c. Porosity (%):	18-21
d. Permeability (md):	0.5-5.0
e. Pressure (psig):	300
f. Temp (deg F):	70
g. Well Spacing (A):	160
2. Production	
a. Natural	
i. Gas (MMcf/d):	15
ii. Oil (BO/d):	0
b. Post-Stimulation - Current Technology	
i. Gas (MMcf/d):	210
ii. Oil (BO/d):	
3. Completion:	
4. Frac Length Required (ft):	150 (model)
5. Frac Gradient (psi/ft):	0.68
6. Frac Type (Gel Wtr, Foam, etc) - Present Technology	N2 Foam
a. Breakdown Acid:	None
b. Foam Quality:	65
c. Breakdown Pressure (psi):	1000
d. Liquid Volume (bbls):	155
e. Sand Placed (sxs):	400
f. Rate (bpm):	30
g. Sand Conc (ppg):	Ramp to 12
h. Avg Treating Pressure (psi):	750
i. Max Treating Pressure (psi):	2500
j. ISIP (psi):	500
k. Costs ($M)	
i. Service Company:	19
ii. CO_2 ($/ton): BOC Gases from Cheyenne (675 mi)	145>245 w/mob
iii. Tanks w/ Trucking:	0
iv. Service Rig:	0
v. Load Water Disposal:	0
vi. Pit - Earthwork, Liner:	0

Figure 5 (p. 2 of 2)

PETROLEUM CONSULTING SERVICES
(330) 499-3823
(330) 499-2280 (fax)

CO_2\SAND STIMULATION CHECKLIST
p. 2 of 2

Date 05/13/98

Formation: Upper Judith River   Operator: Williston Basin Intrst Ppln Co

7. Load Water	
a. Vol Returned (bbls)/%:	30(19%)
b. Time Required (days):	1
c. Vol Retained (bbls):	125
8. Casing - Candidate Wells	
a. Dia (in):	4.5
b. Weight (lb/ft):	10.5
c. Grade:	J-55
d. MWP (psi):	TBD
9. Perforations - Candidate Wells	
a. Depth (ft):	1200
b. Number:	120-285
10. Calorific Value (dth/cuft):	955
11. Pipeline Pressure (psi):	100
12. Allowable CO_2 concentration in Sales Line (%):	2% Tariff
13. Gas Transporter:	WBI
14. Gas Purchaser:	Market
a. Purchase Price ($/dth):	1.28
15. EUR with Current Tech	
a. Gas (MMcf):	300
b. Oil (MBO):	N/A
16. NPV with Current Tech ($M):	161
17. Predict Required EUR for Candidate Wells:	
18. Predict Required NPV for Candidate Wells ($M):	

19. Comments:

Dirty Sandstone
Drilled w/ fresh water polymer - Cannot air drill because of water bearing uphole zone
Available to stimulate in July

05/13/98

X. PERFORATION STRATEGY

The perforating practices employed in this test were changed from those used previously.

Based on the results of tracer surveys, it had been determined, prior to 1998 that the conventional practice of perforating both the Upper and Lower members of the Phillips Sandstone is superfluous and starting in 1998 it was decided to perforate only the Upper member.

The prior strategy had been to perforate both the Upper and Lower Phillips Sand members and then to hydraulically stimulate them both with a single stage treatment. This procedure had been under review for some time and new information became available to support that:

A. The majority, if not all, of the stimulation treatment enters the Upper Phillips member and very little, if any, enters the Lower Phillips. Also, if these two intervals are individually stimulated there is no apparent production benefit.

B. Even with a delayed second stage stimulation, the addition of the Lower Phillips does not increase the gas production rate. This subsequent stimulation of the Lower Phillips did not result in any additional gas production benefit.

These conclusions are based upon radioactive tracer studies on four wells, #'s 985, 995, 997, and 999, which indicated that the Lower Phillips member is untreated, and also the ineffectiveness of a delayed stimulation of the Lower Phillips in a non-traced well, #984. The radioactive tracer logs and the production histories were included with the submittal packages and are summarized in the accompanying well specifics

Well #	
985	Both the Upper and Lower Phillips Sandstone were treated in June 1996 with a single stage stimulation which included radioactive tracer materials. A tracer log indicated that the entire treatment entered the Upper Phillips.
995	Both the Upper and Lower Phillips Sandstone were treated with a single stage stimulation which included radioactive tracer materials in June, 96. A tracer log indicated that the entire treatment entered the Upper Phillips. Additionally, following 11 months of production the Upper Phillips was isolated with a packer and the Lower Phillips was stimulated with 41,000 lbs of proppant, which was pumped through tubing. There was no increase in production.
997	Both the Upper and Lower Phillips Sandstone were treated with a single stage stimulation which included radioactive tracer materials in June 1996. A tracer log indicated that the entire treatment entered the Upper Phillips. Additionally, following 11 months of production the Upper Phillips was isolated with a packer and the Lower Phillips was stimulated with 41,300 lbs of proppant, which was pumped through tubing. There was no increase in production.
999	Both the Upper and Lower Phillips Sandstone were treated in June, 96 with a single stage stimulation which included radioactive tracer materials. A tracer log indicated that there was practically no entry into the Lower Phillips Sandstone

C. Conclusions

1. There is no additional production derived from wells perforated in both the Upper and Lower Phillips Sandstone and then stimulated with a single stage treatment.

2. Where both the upper and lower sand members are perforated and then stimulated with a single stage treatment, the fracturing treatment enters only the upper member.

3. If these two intervals are individually stimulated there is no apparent production benefit.

   In a single well test which had been stimulated in and which was producing solely from the Upper Phillips, there was no additional gas production contributed from the Lower Phillips following the subsequent stimulation (through tubing) of it.

4. The better perforation strategy is to perforate and stimulate only the Upper Phillips Sandstone.

5. It was determined as an outcome of the tracer study that if the Lower Phillips is treated separately, no production advantage is realized. The present view is that if a stimulation is initiated in the Upper sand that it grows downward into the Lower member, because it cannot penetrate the more competent overlying Greenhorn formation. And, if the Lower Phillips is selectively stimulated, that the fracture grows upward into the Upper Phillips. Therefore, the current thinking is that the maximum production benefit is achieved by perforating and stimulating only the Upper Phillips Sandstone. These findings have been recently confirmed and are the basis for perforating all of the wells drilled in the Bowdoin Dome Field, since 1998.

D. Results

As a result of these findings, all of the 20 wells drilled in 1998 were perforated and stimulated only in the Upper Phillips Sandstone. Additionally, all of the subsequent Bowdoin Dome Field wells have been perforated and treated only in the Upper Phillips Sandstone.

E. Concerns Regarding the Number of Perforations

The large number of perforations in the candidate was a concern in that they may result in reduced proppant transport as a consequence of diminished velocities.

This concern was discussed with Canadian Fracmaster because of their familiarity with other successful treatment procedures in the area. They provided assurances that they have executed numerous treatments in very similar zones in southern Alberta which were treated through a large number of perforations and did not experience any unusual difficulty in placing the design proppant volumes. They did not have any concerns regarding the number of perforations proposed.

The treatments went smoothly and there were no problems encountered in placing proppant and no pressure increases were experienced in the first two treatments as the sand concentrations were increased to a maximum of 5.9 and 4.9 ppg respectively.

The last treatment did screen out as the sand concentration was increased. The sand concentration at the surface was 8.2 ppg and the concentration at the perforations was 5.2 pounds per gallon at the tail end of the treatment. This design was intentional to determine the maximum sand acceptance loading. In reality, without being able to discern it, it appears that the likely maximum sand concentration of approximately 5 ppg was approached during the first treatment.

XI. CRITERIA FOR SUCCESS

Upon review of the production responses from the conventionally stimulated wells drilled prior to July, 98 it was agreed that, based upon the available information, the success criteria would be realized if the cumulative production for months 2 through 13 would be 50 MMcf, if they were conventionally stimulated with nitrogen foam and 40,000 pounds of proppant.

By mutual agreement between all parties it was agreed that this should serve as the measure by which the evaluation of the CO_2/sand stimulations would be judged.

	Cum Prod Months 2-13
Well #	(MMcf)
1019	50
1020	50
1021	50

However as noted above, it was subsequently determined - as the production from the project wells became available, that the cumulative gas production for months two through thirteen from all of the wells stimulated in July 1998 - both control and candidates - was lower than these projections. Seven of these new wells, in the test area were conventionally stimulated with N_2 Foam and the two through thirteen month cumulative production from those wells ranged from 16.6 to 54.7 MMcf with an average of 33.1 MMcf, which was much less than the anticipated 50 MMcf.

XII. PRE-TEST CONCLUSIONS

The three candidate wells, 1019, 1020, and 1021 would provide an objective opportunity to demonstrate the CO_2/sand stimulation technology in a controlled experimental environment.

A. The wells have estimated ultimate recoveries (EURs) ranging from 175 to 350 MMcf,

B. That the cumulative productions for months two through thirteen represented a realistic assessment,

C. That because of the conventional practices for the Bowdoin Field wells of employing stimulation treatments with 40,000 lbs of proppant that they did not require lengthy fracture extensions, and therefore were a good "fit" from a comparative job size viewpoint.

D. Based on estimates of a 19% retention of spent stimulation liquids and a belief that the clean up period was being lengthened by this liquid that the reservoir was probably suffering from the damage resulting from the retained stimulation liquids,

E. The projected cumulative production for months 2 through 13 for the candidate wells, if they were conventionally treated with nitrogen Foam was estimated to be 50 MMcf. This served as the basis for comparing the effectiveness of the CO_2/sand technology.

As mentioned above it was subsequently determined that the cumulative gas production volumes from the wells treated in July 1998 were found to be significantly lower than that from the pre-98 wells .

F. The size of the Control Well data set was increased from 8 to 15 by including new wells: #s 1013, 1014, 1017, 1018, 1020, 1021, &1022. Some of the originally proposed Candidate Wells were rejected by the DOE and two of the previously identified Control Wells, 1020 & 1021 became Candidate Wells.

G. The cost of the CO_2/sand stimulations was projected to be 140% greater than that for the current practices: $59,995 vs $25,000 (including $5,000 for N_2)*. This cost differential dictates an un-discounted 1.4 fold increase in the production rate.

*It has been subsequently determined that the cost of a N_2 Foam stimulation including the nitrogen in July 1998, at the time of the demonstration was $18,500. This would result in a required un-discounted 1.6 fold increase in the production rate - if the actual cost of the CO_2/sand stimulation, excluding mobilization were employed [1-(48,124/18,500)].

H. The stimulation costs were burdened by an unexpectedly large cost for CO_2. The distance to the CO_2 supply points is significant and results in an unusually large cost.

It was anticipated that if the production responses from the candidate wells substantiated the cost of the CO_2/sand stimulations, then the increased local demand for CO_2 would ultimately result in a cost reduction and further improve the economics of the non-damaging process.

I. To prevent the possibility of standby charges, $10,000 per day, four on-site portable storage units were utilized.

J. WBI controls a significant reservoir position and, if the benefits of CO_2/sand stimulations were economically supported, then they would likely continue these efforts. The 1998 drilling program included 20 new wells.
At the time, there were an additional 65 Bowdoin Dome wells planned which subsequently have been drilled.

K. The Phillips Sand wells were being completed in a 300 psi reservoir and were reportedly returning only a small portion of the stimulation liquids, they were estimated to be 1,260 gallons or 19 percent. This retained stimulation liquid could be inhibiting the gas production from this thick, low permeability gas reservoir, although there is no obvious difference in the gas production from the wells completed when the reservoir was at a higher pressure.

XIII. LETTER OF INTENT

A letter of intent which identified the candidate wells, specified the criteria for success, and the required responses of all parties was developed and executed. It was then forwarded to the DOE for consideration with the proposal package (Figure 6).

Figure 6 (p. 1 of 5)

PETROLEUM CONSULTING SERVICES
P.O. Box 35833
Canton, Ohio 44735
(330) 499-3823

June 14, 1998

Mr. Dennis Zander - Staff Engineer
c/o Mr. Don Brutlag - Superintendent
Gas Production and Storage
Williston Basin Interstate Pipeline Co.
P. O. Box 131
Glendive, MT 59330

Via Fax (406) 359-7273

Re: CO_2\Sand Stimulations - DOE Cost-Shared Demonstration - Letter of Intent - Liability Release

Dear Don,

I spoke with Dennis on Friday and relayed the latest from Fracmaster. Following a review of CO_2\sand stimulations in the Milk River formation approximately 150 miles northwest of Saco, it appeared that the CO_2 requirements and therefore the stimulation costs could be reduced. Dennis relayed that he will be away for the next two weeks and will be in touch, but that I should forward the Letter of Intent and Liability Release to you for processing - they are attached. Please see that they are executed as quickly as possible and return them to me. My fax number is (330) 499-2280.

Additionally, I've had several conversations with Mr. John Edwards at Fracmaster regarding these modifications since my conversation with Dennis on Friday afternoon, and received a revised cost proposal from him yesterday. Dennis should have received a fax also. Let me know if you need a copy and I'll fax you one. The details are:

PROPPANT FLUID SCHEDULE

Stage		Cum Fluid (bbl)	Stage Fluid (bbl)	Proppant Conc (ppg)	Proppant Stage (lb)	Cum Proppant (lb)
Hole Fill	(Liquid CO_2)	25.0	25.0			
Pad	(Liquid CO_2)	190.0	165.0			
Start	(20/40 Sand)	220.0	30.0	0.8	1,000	1,000
Increase	(20/40 Sand)	260.0	40.0	1.7	2,850	3,850
Increase	(20/40 Sand)	410.0	150.0	2.5	15,750	19,600
Increase	(20/40 Sand)	587.0	177.0	3.3	24,500	44,100
Flush	(Liquid CO_2)	758.0	19.0			

TREATMENT FLUID REQUIREMENTS

	Hole	Pad	Prop	Flush	Bottoms	Tot
Liquid CO_2 (bbl)	25.0	165.0	422.0	19.0	189.0	820.0
Nitrogen (SCF)						19,415.0

Figure 6 (p. 2 of 5)

ltr: Mr. Dennis Zander c/o Mr. Don Brutag; 06/14/98
CO_2\Sand Stimulations - DOE Cost-Shared Demonstration - Letter of Intent - Liability Release
p. 2 of 2

The resultant costs for stimulating these wells with the CO_2\sand technology are:

Equipment	$16,053.79
Materials	36,957.65
CO_2	incl
	53,011.44
Computer Control Center	1,080.00
Report	427.50
	54,518.94
3 wells (x3)	163,556.82
Mobilization	17,500.00
	181,056.82
Per well (÷3)	60,352.27
Cost To WBI	30,176.14
Cost To DOE	30,176.13
	$60,352.27

Additionally, Fracmaster is projecting a wellhead treating pressure of 1293 psi and therefore the 3000 psi working pressure control valves should be more than sufficient. That is, there is no need to procure 5000 psi hardware.

I have prepared a revised proposal, which was finished this afternoon and will hand deliver it to the DOE at Morgantown in the morning. I have scheduled a meeting to discuss these revisions and feel that the plans to CO_2\sand stimulate the week of July 13th are realistic. A copy of the revised proposal is being forwarded to your offices via overnight delivery.

I'm planning to arrive in Saco on July 8th to observe a few foam fracs and to finalize details with Fracmaster, and will coordinate these plans with Dennis.

I have prepared a prognosis for these treatments per your request and, now that I know the projected wellhead treating pressures, will complete it and get it to you.

Please let me know if you have any questions.

Sincerely,

Raymond L. Mazza

attachments
- Letter of Intent - 3 pp
- Liability Release - 1 pp
- Package 5A Dialog - 7 pp

Figure 6 (p. 3 of 5)

Letter of Intent
(p. 1 of 3)

June 15, 1998

Operator: Williston Basin Interstate Pipeline Co (WBI)
A subsidiary of MDU Resources Group

Candidate Wells: Bowdoin Dome - Phillips Co, Montana

Well #	Twp	Rge	Sec	Quad	API No 25-071-	Status	Treat
1019	33N	32E	34	SE	TBD	New	July 98
1020	32N	32E	01	NW	TBD	New	July 98
1021	32N	32E	12	NW	TBD	New	July 98

Target Formation: Phillips Sands

Production Projections - Cumulative for Months #2 through 13:

Well #	MMcf
1019	50
1020	50
1021	50

Control Wells:

Well #	Twp	Rge	Sec	Quad	API No 25-071-	Status	Treat
972	33N	32E	27	NW	22267	Existing	N/A
973	33N	32E	32	SE	22268	Existing	N/A
974	33N	32E	33	NE	22269	Existing	N/A
976	33N	32E	35	NW	22272	Existing	N/A
990	32N	32E	02	NW	22275	Existing	N/A
991	32N	32E	01	NE	22279	Existing	N/A
997	33N	32E	32	NE	22287	Existing	N/A
1000	32N	32E	02	SE	22283	Existing	N/A
1002	33N	32E	33	SE	22288	Existing	N/A
1013	32N	32E	03	NW	TBD	New	July 98
1014	33N	32E	31	NE	TBD	New	July 98
1015	33N	32E	29	NW	TBD	New	July 98
1016	33N	32E	28	SE	TBD	New	July 98
1017	33N	32E	27	SW	TBD	New	July 98
1018	33N	32E	34	NE	TBD	New	July 98
1022	32N	32E	12	NE	TBD	New	July 98
1023	32N	32E	13	SE	TBD	New	July 98

The liquid CO_2\proppant stimulation process is beneficial in reservoirs that are liquid sensitive. This is because the process utilizes liquid carbon dioxide (CO_2) as a treating fluid to both fracture the reservoir strata and to transport proppant, the liquid CO_2 vaporizes following the stimulation and a completely dry fracturing treatment results.

The U. S. Department of Energy will, subject to their approvals, agree to provide cost-shared funding for the stimulation of these candidate wells with Fracmaster's closed system blender for liquid CO_2\proppant treatments, if certain criteria are met. WBI agrees to bear the remaining expenses.

Figure 6 (p. 4 of 5)

Letter of Intent
p. 2 of 3

June 15, 1998

The project entails demonstrating the liquid CO_2\proppant process in a controlled environment where sufficient background production information from nearby wells can be used to compare the production results with the CO_2\proppant technology.

The design of the stimulation treatments is to consist of approximately 120 tons of liquid carbon dioxide and up to 44,000 pounds of 20/40 sand proppant pumped at injection rates of 50 to 60 barrels per minute, and to consist of a single-stage treatment.

Because the liquid-free CO_2\proppant process provides a completely dry stimulation it is imperative that liquids not be introduced into the wellbore following these treatments. WBI agrees to make every effort to avoid "killing" these wells with water and will only kill a well in the event of an environmental or safety emergency. In the event of the need to introduce water into the well, WBI will immediately notify Petroleum Consulting Services (PCS) prior to the treatment, if possible.

The candidate wells will be turned in line shortly after stimulation and will be operated at wellhead pressures of 120 psi or less. This is to enable a meaningful comparison of the technologies to be made.

WBI agrees to provide monthly production (gas, oil, and water) and pressure data for both the candidate and the control wells for a period of five (5) years. The monthly production information, including any recordings, shall be forwarded to PCS.

Proppant, if any, will be removed from the wellbore at the operator's expense. No liquids will be circulated for the clean-out unless written approval is obtained from the DOE.

The DOE, subject to their approval of the submitted information, which includes:

1. Letter of intent	This document
2. A map of the candidate well and nearby offsetting wells	
3. Electric logs	Control and candidate wells
4. Cumulative production data	Control and candidate wells
5. Monthly pipeline pressure data	Control and candidate wells
6. Stimulation records tabular and strip charts	Control and candidate wells
7. Well completion reports	Control and candidate wells
8. Description of the field activity	Candidate Wells
9. Schedule for treating the candidate wells	October 17th and 18th
10. Liability Release (PCS)	Attached

Will, through the contractor, Petroleum Consulting Services, pay for one-half (1/2) of the costs of the stimulations, including the service company charges for product (CO_2, proppant), services, and mobilization.

WBI hereby indicates an intention to enter into a 50/50 cost-shared participation of the stimulation expenses for these candidate wells, subject to DOE approvals.

Figure 6 (p. 5 of 5)

Letter of Intent
(p. 3 of 3)

June 15, 1998

WBI agrees to bear the remaining expenses of these treatments and any remaining activities, i.e., those expenses normally associated with these treatments: cement bond log, perforating, dozers, service rigs, etc.

If these conditions are satisfactory, please acknowledge by signing below, and returning this document to:

Petroleum Consulting Services
P. O. Box 35833
Canton, Ohio 44735
(330) 499-3823 (330) 499-2280 (fax)

Date: 6/17/98

Signed: Tory J. Finneman
Company Officer

Title: Vice President - Operations

Witness: Don Buttag

XIV. DOE APPROVALS

The DOE, upon review of the initial proposal package(#5), and the subsequent response to their interrogatory questions which involved the substitution of two of the initially proposed candidate wells (Two of the wells, 1015 and 1017 were rejected as being influenced by the thinning of the sand, reduced cumulative production, and porosity reduction resulting from the influence of the tear fault), and the re submittal of an amended proposal(#5A) agreed and returned a written approval (Figure 7) of the test and the associated expenditures.

Figure 7 (p. 1 of 3)

PETROLEUM CONSULTING SERVICES
P.O. Box 35833
Canton, Ohio 44735
(330) 499-3823

June 25, 1998

Mr. Dennis Zander - Staff Engineer
Gas Production and Storage
Interstate Pipeline Co.
P. O. Box 131
Glendive, MT 59330

Via FAX: (406) 359-7273

Re: CO_2\Sand Stimulation - DOE Approval of Cost-Shared Project

Dear Mr. Zander,

I have received written approval from the DOE (attached) to proceed with the CO_2\Sand stimulation project for the three candidate wells; 1019, 1020, and 1021. The wells are to be completed in the Upper Phillips only as. The DOE has agreed to pay for one-half of the stimulation costs as described in the Letter of Intent providing that the provisions are satisfied.

The approved cost reimbursements are based upon the following costs:

Location	Saco
County	Phillips
Stage(s)	1
Depth(ft)	1591
Horsepower(HHP)	1806
CO_2 Supply Point	Medicine Hat, Albta
Requirement(tons)	151
Distance(mi)	310
Delivered Cost($/2000lbs)	200
Cost-per stage($)	30,200.00
Cost-per well ($)	30,200.00
Equipment-per well	16,053.79
Proppant-Delivered($)	6,757.65
CO_2	30,200.00
Computer Control Center	1,080.00
Report	427.50
	54,518.94
3 wells (x3)	163,556.82
Mobilization	17,500.00
	$181,056.82

Figure 7 (p. 2 of 3)

ltr: Mr. Dennis Zander; 06/25/98
CO_2\Sand Stimulation - DOE Approval of Cost-Shared Project
p. 2 of 2

Per well (÷3)	60,352.27
Total Cost To WBI	90,528.41
Total Cost To DOE	90,528.41
	$181,056.82

* Charges per day - based on 2 stages per day

My present plans are to arrive in Billings on Wednesday, July 8th and to meet with you and John Edwards to discuss the operational details and to make plans for stimulating the three candidate wells starting Monday, July 13th. I know that you are scheduled to be in the field executing the foam fracs on the other wells. Please let me know where it would be convenient to meet.

Sincerely,

Raymond L. Mazza
Project Manager

attachments:
DOE Approval (1 pp)

Figure 7 (p. 3 of 3)

U. S. Department of Energy
Federal Energy Technology Center

3610 Collins Ferry Road
P.O. Box 880
Morgantown, WV 26507-0880

626 Cochrans Mill Road
P.O. Box 10940
Pittsburgh, PA 15236-0940

FETC
We Solve National Energy and Environmental Problems

June 25, 1998

Mr. Ray Mazza, President
Petroleum Consulting Services
P.O. Box 35833
Canton, OH 44735

Re: Approval of DOE Cost-Shared Participation in Stimulating Three Williston Basin Interstate (WBI) Wells with CO_2/Sand.

Dear Mr. Mazza:

Approval is granted for participation in the Upper Phillips Sand Project in Phillips County, Montana. As stated in the letter of intent, DOE will pay for 50 per cent of the stimulation invoice costs. The three wells approved for CO_2/Sand stimulation are (WBI numbers): 1019, 1020, and 1021.

WBI must provide all the flow down deliverables in the signed letter of intent. Following stimulation, WBI must provide monthly production data as specified in the letter of intent.

DOE is eager to test the potential of this new fracturing process in increasing gas production rates as well possibly increasing overall reserves at this field site. If successful, we would encourage their adoption and use of this process as the method of choice in their future well drilling and stimulation programs in this area.

Sincerely,

Albert B. Yost II

Albert B. Yost II
Project Manager/COR

XV. FIELD ACTIVITIES

A. Preparations

Preparations for the field activities included perforating the candidate wells and the placement of two 70 ton CO_2 storage vessels on the location and then filling them with liquid CO_2 during the 24 hour period prior to the treatment.

B. Wellhead Isolation Tool

On the morning of the treatments, a wellhead isolation tool was run to comply with the pressure rating of the wellhead valving etc.

C. Stimulations

A summary of the perforation, stimulation specifics (volumes, rates, pressures), and cost information for all three wells is presented (Figure 8) and the individual job summary logs and rate-pressure-sand concentration plots for each well are also included as noted below.

Figure 8 (p. 1 of 3)

PETROLEUM CONSULTING SERVICES
P.O. BOX 35833
CANTON, OH 44735
(330) 499-3823

STIMULATION SUMMARY - ONE STAGE

DATE: 07/16/98 PAGE 1 OF 3

WELL:	1019	1020	1021
TARGET:	U PHILLIP	U PHILLIPS	U PHILLIPS
SEC/TWP/R	34/33N/32I	01/32N/32E	12/32N/:
F?L/F?L:	1630S/144(	1600N/1600	1065N/1361E
CO/ST:	PHILLIPS/	PHILLIPS/M	PHILLIPS/MT
PMT #(25-07	22460	22454	22244
OPERATOR	WBI	WBI	WBI
ELEV GL:	2290	2277	2273
TOT DPTH:	1250	1224	1220
COMPLTED	06/09/98	06/07/98	06/06/98
STIMULATE	07/16/98	07/15/98	07/14/98
PERFS:	40	40	40
TOP:	984	975	970
BOT:	994	985	980
	—	—	—
INTERVAL:	10	10	10
ACID(GAL):	0	0	0
CO2(BBLS):	321	447	536
(TONS):	62	86	103
(MMCF):	1.1	1.5	1.8
CLDWN&LOSS			
(TONS):	23	27	36
TOTAL	====	====	====
(TONS):	85	113	140
INV(TONS):	84	113	138
BOT(TONS)	59	30	5
PAD(BBLS):	16	15	14
SL(BBLS):	305	420	510
FLUSH(BBL:	0	13	13
	—	—	—
PMP(BBLS):	321	447	536
SAND(SXS):	430	441	441
IN WELL:	44	7	7
	—	—	—
NET(SXS):	386	434	434
MESH:	20/40	20/40	20/40
N2 (MCF):	101	134	159
RATE(BPM)			
A'	40.9	45.9	45.3
M	42.1	47.2	45.9
PRESS(PSI)			
A'	754	870	943
M	2886	1363	1740

Figure 8 (p. 2 of 3)

07/16/98 PAGE 2 OF 3

WELL:	1019	1020	1021
SND CONC(PPG)			
A'	3.4	2.5	2.1
M	8.2	4.9	5.9
HORSEPOWER			
A'	756	979	1046
M	2981	1577	1959
PRESS AT PERFS:			
@BREAKDOWN(PSI)		1363	1856
GRAD(PSI/FT):		1.40	1.91
@AVG P(P	422	541	650
@MAX P(P	N/A	-120	1447
@ISIP(PSI	N/A	638	564
GRAD(PSI/F	N/A	0.65	0.58
BRK DWN(F	1450	1363	1856
PRE ISIP(PSI):		972	860
RATE(BPM);		46	44
ISIP(PSI):	N/A	174	102
F(PSI/100FT	N/A	81	78
1 MIN(PSI):	276	174	
2 MIN(PSI):		160	
2 MIN(PSI):		174	
15 MIN(PSI)	261	218	247
PRESS:			
OPN FLO:			
TIL:			

Figure 8 (p. 3 of 3)

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07/16/98 PAGE 3 OF 3

WELL:	1019	1020	1021		
0	------	------	------		
PUMPING($	17,133	17,133	17,134	51,400	
N2	incl	incl	incl		
N2-MILEAGI	incl	incl	incl		
N2-TRANSP	incl	incl	incl		
N2-PUMPIN	incl	incl	incl		
SAND *	2,932	2,933	2,933	8,797	
SAND-MILE	3,825	3,825	3,825	11,475	
	----	----	----	----	
	23,890	23,891	23,891	71,672	
CO2 *	16,800	22,560	27,640	67,000	
CO2-TRANS	5,700			5,700	CO2 RETURNED
CO2-PORT	incl	incl	incl		
BLENDER	incl	incl	incl		
LISC FEE					
TUBE TRLR	incl	incl	incl		
CO2-MILEA	incl	incl	incl		
	----	----	----	----	
	22,500	22,560	27,640	72,700	
MOBILIZATI	5,833	5,833	5,833	17,500	
TRCKNG					
TREE SAVE	2,181	2,181	2,181	6,543	
MISC					
	----	----	----	----	
T	54,404	54,465	59,546	168,415	168,415
$/SK	141	125	137		

SCREENOUT
@7.5PPG,
STARTED @6.5PPG
(5,2PPG @ PERFS)
44 SXS IN CSG
FILL UP=300 FT

1. Stimulation #1 - Well 1021

The first well stimulated with CO_2/sand was well #1021. It was stimulated with 44,100 lbs of 20/40 API specification proppant and 103 tons of liquid CO_2 on July 14th, 1998. The treatment consisted of a total of 536 Barrels of liquid CO_2 pumped at an average rate of 45.3 barrels per minute and an average pressure of 943 psi and a maximum of 1740 psi and was pumped through 40 perforations in the 4-1/2 in casing located between depths of 970 and 980 feet.

The breakdown pressure was 1856 psi and the fracturing gradient was 0.51 psi/ft. The sand proppant was pumped at an average sand concentration of 2.1, and a maximum of 5.9 lbs/gal. At the termination of the pumping activity the instantaneous shut in pressure was 102 psi. The treatment design was to intentionally under flush to provide a proppant packed fracture to the well bore and an estimated quantity of 700 lbs was left in the casing - leaving an in-zone total of 43,400 lbs. The tabulated Frac Treatment Report and plotted information summarizing these activities is presented in Figures 9 and 10.

Figure 9

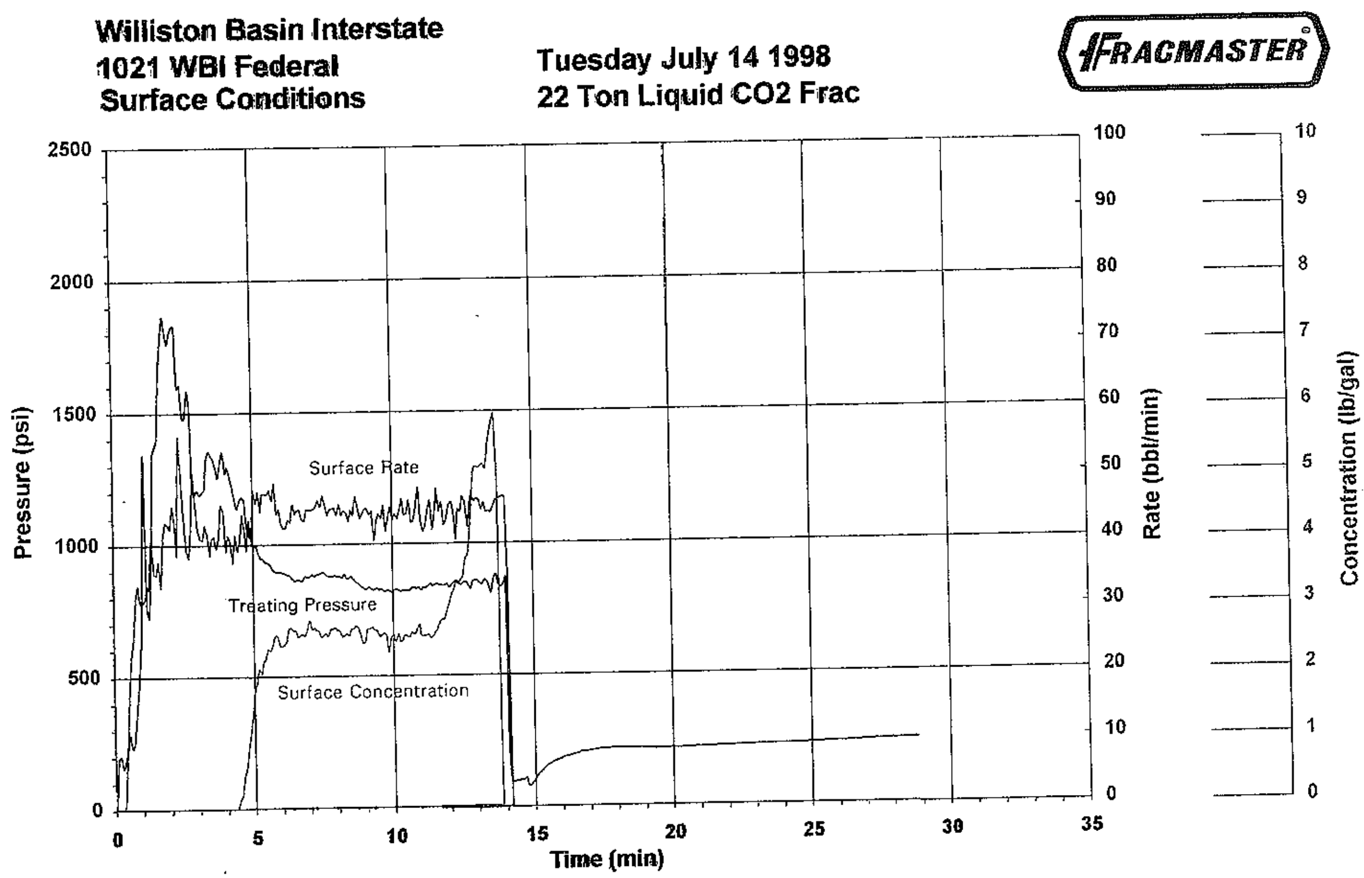

Williston Basin Interstate
1021 WBI Federal
Surface Conditions
Tuesday July 14 1998
22 Ton Liquid CO2 Frac
FRACMASTER
Surface Rate
Treating Pressure
Surface Concentration
Pressure (psi)
2500
2000
1500
1000
500
0
Rate (bbl/min)
100
90
80
70
60
50
40
30
20
10
0
Concentration (lb/gal)
10
9
8
7
6
5
4
3
2
1
0
0
5
10
15
20
25
30
35
Time (min)

Figure 10

FRACMASTER

FRAC TREATMENT REPORT

OWNER	Williston Basin Interstate
ADDRESS	P.O. Box 131
CITY	Glendive, MT
	59330-0131

SERVICE ORDER NO:	99943
DATE:	7/14/98
JOB TYPE:	20.0 Tonne Liquid CO2 Frac
WELL NAME AND NO.:	WBI Federal
LOCATION:	1021
FLUID TYPE:	Liquid CO2
PROGRAM NO:	WFM025

	O.D.	WT.	Depth	Vol.	Max.
Tubing					
Casing	4.5	9.50	970.0	15.78	4379.9
Total				15.78	

Packer Depth N/A ft PBTD 1146.0 ft

Formation Treated: Eagle/Phillips

PERFORATIONS	From	To	Zone Treated	SPF
INTERVALS	970.0	980.0	x	4

FLUSH FLUID DENSITY	9.02	lb/gal
ESTIMATED SAND TOP:	1102.0	feet
FRACTURE GRADIENT:	0.51	psi/ft
BREAKDOWN PRESSURE:	1856.4	psi
Instantaneous Shut In Pressure:	101.5	psi
ONE Minute Shut In Pressure:	101.5	psi
15 Minute Shut In Pressure:	246.6	psi

CO_2 PUMPED:	536.0	bbl/min
CO_2 COOLDOWN & LOSSES:	188.7	bbl/min
CO_2 TOTAL USED:	724.7	bbl

	MIN.	MAX.	AVE.	UNITS
PRESSURE	826.7	1740.4	942.7	psi
RATE	44.0	45.9	45.3	bbl/min
HORSEPOWER	892	1959	1046	hp
AVAILABLE hp		5830	3	Units

PROPPANT DATA

PROPPANT AGENTS	PUMPED lbs	MESH	CONC. START	lb/gal END	IN FORM. lb	CONC.@ PERFS	TOTAL PROP (lb) USED	IN FORM.
Sand	44,090	20/40	0.2	5.1	43,429	5.1	44090	43429

Arrived at location 7:00 Hours
Left Location at 17:00 Hours

TIME	PRESS. Psi Casing		STAGE VOLUMES bbl Cum Fluid	Fluid	Slurry	RATE bbl/min	Downhole		Downhole Sand Conc.	REMARKS:
15:54:19	174.0						0-25-0			Start hole fill. (Liquid CO_2)
15:55:54	1856.4		13.8	13.8			25-45.0			Hole full, start pad. (Liquid CO_2)
15:58:29	1160.3		164.8	151.0	47.2		45.0		0.2-2.66	Pad away, start sand stage #1.
15:59:44	1000.7		208.8	44.0	254.1		45.0		2.66	Sand stage #1 away, start sand stage #2.
16:05:39	841.2		435.3	226.5	104.0		45.0		2.66-5.1	Sand stage #2 away, start sand stage #3.
16:07:29	841.2		523.4	88.1			45.0		5.1-0	Sand away, start flush. (Liquid CO_2)
16:08:09	870.2		536.0	12.6			45.0-0			Flush away stop pumps.

VOLUME PUMPED	536.0	bbl
VOLUME IN FORMATION	533.8	bbl

Pressure test surface lines to:	4350.0 Psi	Annular relief valve:	N/A	Psi
Maximum treating pressure:	3770.0 Psi	Hold annulus at:	N/A	Psi

FRACMASTER REPRESENTATIVE: Gord Milgate, Gary McLean

CUSTOMER REPRESENTATIVE: Dennis Zander /Ray Mazza

2. Stimulation #2 - Well 1020

The second well stimulated with CO_2/sand was well #1020. It was stimulated with 44,100 lbs of 20/40 API specification proppant and 86 tons of liquid CO_2 on July 15th, 1998. The treatment consisted of a total of 447 Barrels of liquid CO_2 pumped at an average rate of 45.9 barrels per minute and an average pressure of 870 psi and a maximum of 1363 psi and was pumped through 40 perforations in the 4-1/2 in casing located between depths of 975 and 985 feet.

The breakdown pressure was 1363 psi and the fracturing gradient was 0.42 psi/ft. The sand proppant was pumped at an average sand concentration of 2.5, and at a maximum of 4.9 lbs/gal. At the termination of the pumping activity the instantaneous shut in pressure was 174 psi. The under flush proppant quantity was 700 lbs resulting in an in-zone total of 43,400 lbs. The tabulated Frac Treatment Report and plotted information summarizing these activities is presented in Figures 11 and 12.

Figure 11

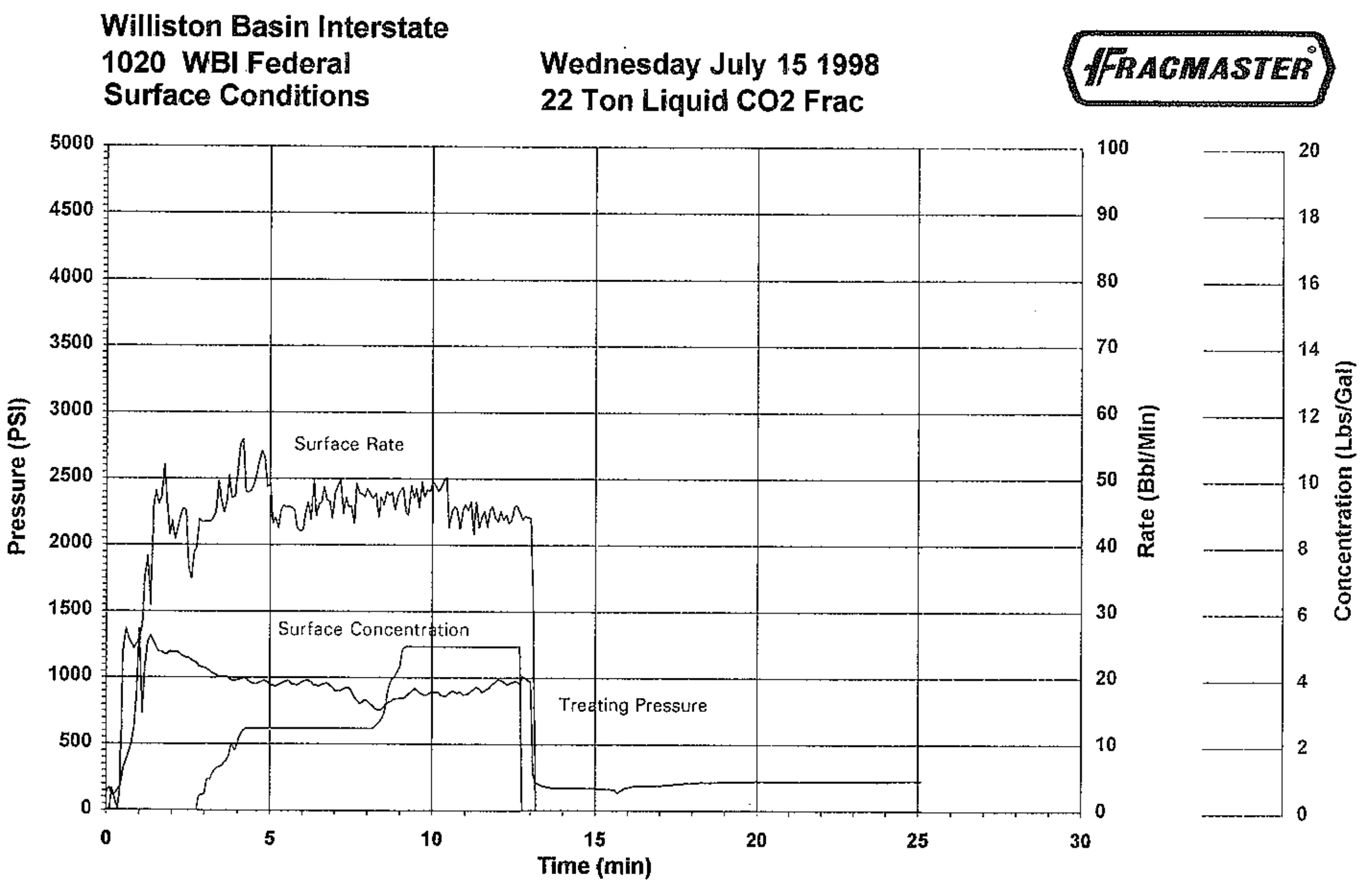

Williston Basin Interstate
1020 WBI Federal
Surface Conditions
Wednesday July 15 1998
22 Ton Liquid CO2 Frac
FRACMASTER
Pressure (PSI)
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
Surface Rate
Surface Concentration
Treating Pressure
0
5
10
15
20
25
30
Time (min)
Rate (Bbl/Min)
100
90
80
70
60
50
40
30
20
10
0
Concentration (Lbs/Gal)
20
18
16
14
12
10
8
6
4
2
0

Figure 12

FRACMASTER

FRAC TREATMENT REPORT

OWNER	Williston Basin Interstate
ADDRESS	P.O. Box 131
CITY	Glendive, MT 59330-0131
SERVICE ORDER NO:	99944
DATE:	7/14/95
JOB TYPE:	20.0 Tonne Liquid CO2 Frac
WELL NAME AND NO.:	WBI Federal
LOCATION:	1020
FLUID TYPE:	Liquid CO2
PROGRAM NO:	WFM025

	O.D.	WT.	Depth	Vol.	Max.
Tubing					
Casing	4.5	10.50	975.0	15.78	4379.9
Total				15.78	

Packer Depth N/A ft PBTD 1146.0 ft
Formation Treated: Eagle/Phillips

PERFORATIONS	From	To	Zone Treated	SPF
INTERVALS	975.0	985.0	x	4

CO_2 PUMPED: 449.8 bbl
CO_2 COOLDOWN & LOSSES: 141.5 bbl
CO_2 TOTAL USED: 591.3 bbl

FLUSH FLUID DENSITY	9.02	lb/gal
ESTIMATED SAND TOP:	950.0	feet
FRACTURE GRADIENT:	0.42	psi/ft
BREAKDOWN PRESSURE:	1363.3	psi
Instantaneous Shut In Pressure:	174.0	psi
ONE Minute Shut In Pressure:	174.0	psi
15 Minute Shut In Pressure:	217.5	psi

	MIN.	MAX.	AVE.	UNITS
PRESSURE	754.2	1363.3	870.2	psi
RATE	25.2	47.2	45.9	bbl/min
HORSEPOWER	465	1577	979	hp
AVAILABLE hp		5830	3	Units

PROPPANT DATA

PROPPANT AGENTS	PUMPED lbs	MESH	CONC. START	lb/gal END	IN FORM. lb	CONC.@ PERFS	TOTAL PROP (lb) USED	TOTAL PROP (lb) IN FORM.
Sand	44,090	20/40	0	4.9	43,429	4.9	44090	43429

Arrived at location 7:00 Hours
Left Location at 17:00 Hours

TIME	PRESS. Psi Casing		STAGE VOLUMES bbl Cum Fluid	Fluid	Slurry	RATE bbl/min	Downhole		Downhole Sand Conc.	REMARKS:
12:39:43	116.0						0-25.0			Start hole fill. (Liquid CO_2)
12:40:33	1363.3		14.5	14.5			25-46.0			Hole full, start pad. (Liquid CO_2)
12:42:23	1073.2		94.4	79.9			46.0		0-2.37	Pad away, start sand stage #1.
12:43:38	971.7		138.4	44.0			46.0		2.37	Sand stage #1 away, start sand stage #2.
12:47:43	783.2		301.9	163.6			46.0		2.37-4.9	Sand stage #2 away, start sand stage #3.
12:48:53	841.2		333.4	31.5			46.0		4.9	Sand away, start flush. (Liquid CO_2)
12:52:08	971.7		434.0	100.6			46.0		4.9-0	Flush away stop pumps.
12:52:38	1000.7			12.6						

VOLUME PUMPED	446.6	bbl
VOLUME IN FORMATION	444.3	bbl

Pressure test surface lines to: 4350.0 Psi — Annular relief valve: N/A Psi
Maximum treating pressure: 3770.0 Psi — Hold annulus at: N/A Psi

FRACMASTER REPRESENTATIVE: Gord Milgate, Gary McLean
CUSTOMER REPRESENTATIVE: Dennis Zander /Ray Mazza

3. Stimulation #3 - Well 1019

The third well stimulated with CO_2/sand was well #1019. It was stimulated with 32,100 lbs of 20/40 API specification proppant and 62 tons of liquid CO_2 on July 16th, 1998. The treatment consisted of a total of 321 barrels of liquid CO_2 pumped at an average rate of 40.9 barrels per minute and an average pressure of 754 psi and a maximum, at screen out, of 2,886 psi and was pumped through 40 perforations in the 4-1/2 in casing located between depths of 984 and 994 feet.

The breakdown pressure was 1450 psi and the fracturing gradient was undetermined because of the abnormally high pressure at the end of the treatment due to the screen out. The tabulated Frac Treatment Report and plotted information summarizing these activities are presented in Figures 13 and 14. The sand proppant was pumped at an average sand concentration of 3.4, with a maximum of 8.2 lbs/gal. At the termination of the pumping activity the pressure was 2886 psi. An estimated quantity of 4,400 lbs (300 ft) was left in the well bore above the perforations.

The quantity of CO_2 employed in the Candidate Wells was reduced as the treatments progressed and it was learned that proppant could be placed with lesser volumes. The initial design was modified towards the end of the sand schedule to determine if the sand acceptance concentration could be increased. As the treatments progressed it was learned that much higher than projected sand concentrations could be pumped and therefore the sand placement required lesser CO_2 volumes, and that reduced treatment costs would be realized.

Figure 13

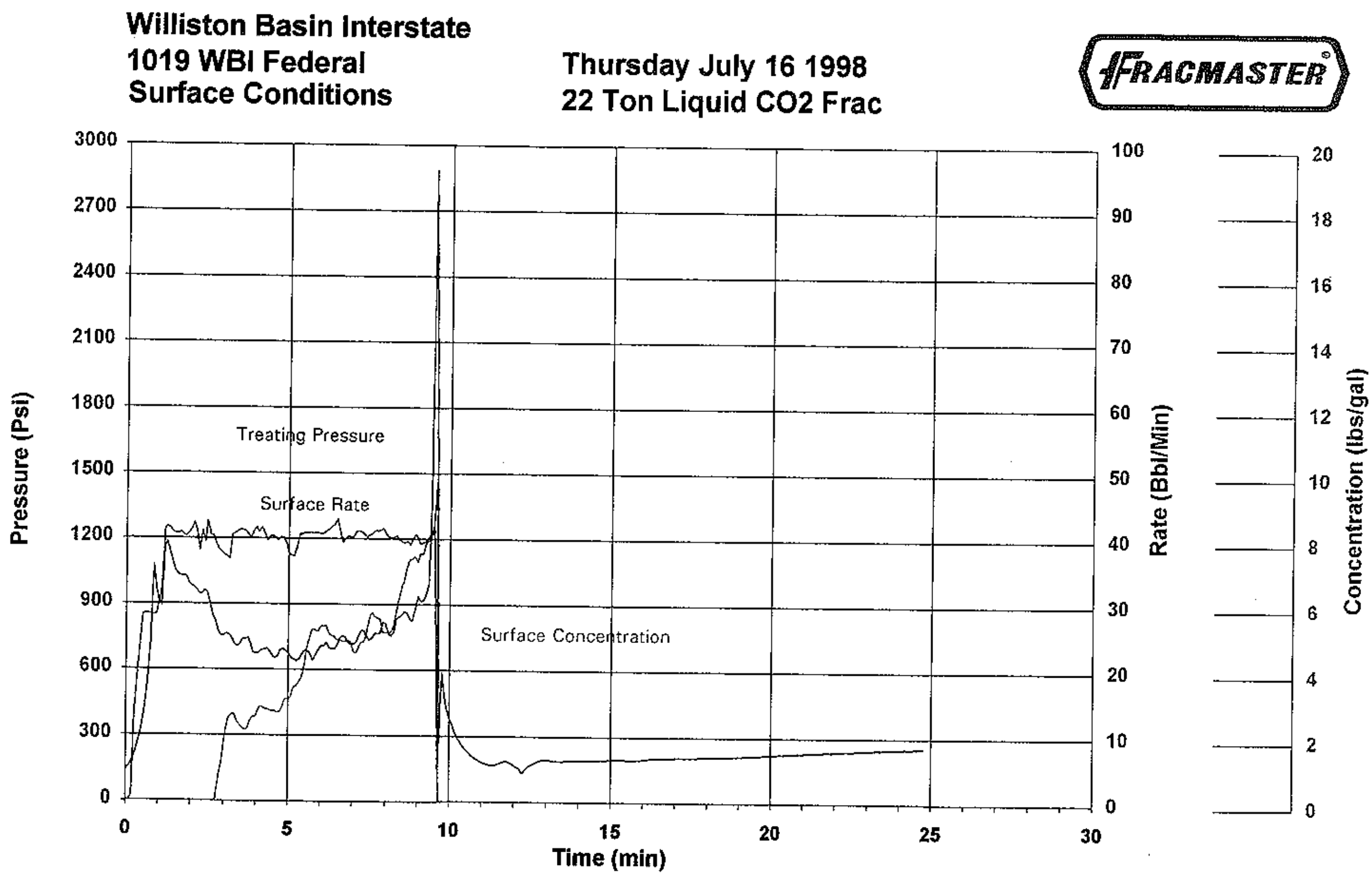

Williston Basin Interstate
1019 WBI Federal
Surface Conditions
Thursday July 16 1998
22 Ton Liquid CO2 Frac
FRACMASTER
Pressure (Psi)
3000
2700
2400
2100
1800
1500
1200
900
600
300
0
Treating Pressure
Surface Rate
Surface Concentration
Rate (Bbl/Min)
100
90
80
70
60
50
40
30
20
10
0
Concentration (lbs/gal)
20
18
16
14
12
10
8
6
4
2
0
0
5
10
15
20
25
30
Time (min)

Figure 14

FRACMASTER

FRAC TREATMENT REPORT

OWNER	Williston Basin Interstate
ADDRESS	P.O. Box 131
CITY	Glendive, MT
	59330-0131

SERVICE ORDER NO:	99945
DATE:	7/16/98
JOB TYPE:	20.0 Tonne Liquid CO2 Frac
WELL NAME AND NO.:	WBI Federal
LOCATION:	1019
FLUID TYPE:	Liquid CO2
PROGRAM NO:	WFM025

	O.D.	WT.	Depth	Vol.	Max.
Tubing					
Casing	4.5	10.50	984.0	15.97	4379.9
Total				15.97	

Packer Depth N/A ft PBTD N/A ft
Formation Treated: Eagle/Phillips

PERFORATIONS	From	To	Zone Treated	SPF
INTERVALS	984.0	994.0	x	4

CO_2 PUMPED:	320.8	bbl
CO_2 COOLDOWN & LOSSES:	119.5	bbl
CO_2 TOTAL USED:	440.3	bbl

FLUSH FLUID DENSITY	9.02	lb/gal
ESTIMATED SAND TOP:	950.0	feet
FRACTURE GRADIENT:	N/A	psi/ft
BREAKDOWN PRESSURE:	1450.3	psi
Instantaneous Shut In Pressure:	N/A	psi
ONE Minute Shut In Pressure:	275.6	psi
15 Minute Shut In Pressure:	261.1	psi

	MIN.	MAX.	AVE.	UNITS
PRESSURE	667.2	2886.1	754.2	psi
RATE	28.3	42.1	40.9	bbl/min
HORSEPOWER	463	2981	756	hp
AVAILABLE hp		5830	3	Units

PROPPANT DATA

PROPPANT AGENTS	PUMPED lbs	MESH	CONC. START	lb/gal END	IN FORM. lb	CONC.@ PERFS	TOTAL PROP (lb) USED	TOTAL PROP (lb) IN FORM.
Sand	42,988	20/40	0	8.2	38,579	7.5	42988	38579

Arrived at location 7:00 Hours
Left Location at 17:00 Hours

TIME	PRESS. Psi Casing	PRESS. Psi	STAGE VOLUMES bbl Cum Fluid	Fluid	Slurry	RATE bbl/min	Downhole		Downhole Sand Conc.	REMARKS:
11:44:12	174.0						0-28.0			Start hole fill. (Liquid CO_2)
11:44:02	1450.3		15.7	15.7			28-40.9			Hole full, start pad. (Liquid CO_2)
11:47:07	768.7		94.4	78.6			40.9		0.41-5.01	Pad away, start sand stage #1.
11:49:52	667.2		188.7	94.4	106.3		40.9		5.00	Sand stage #1 away, start sand stage #2.
11:52:17	754.2		270.5	81.8	100.6		40.9		5.0-8.2	Sand stage #2 away, start sand stage #3.
11:53:37	2886.1		320.8	50.3	66.0		40.9-0		8.2-0	Maximum Pressure, stop pumps.

VOLUME PUMPED	320.8	bbl
VOLUME IN FORMATION	318.3	bbl

Pressure test surface lines to:	4350.0	Psi
Maximum treating pressure:	3770.0	Psi
Annular relief valve:	N/A	Psi
Hold annulus at:	N/A	Psi

FRACMASTER REPRESENTATIVE
Gord Milgate Gary McLean

CUSTOMER REPRESENTATIVE
Dennis Zander /Ray Mazza

This last treatment did screen out as the sand concentration was increased and the sand concentration at the perforations was 5.2 ppg - the recorded sand loading at the surface was 8.2 pounds per gallon at the tail end of the treatment. This design was intentional to determine the maximum sand acceptance loading. In reality, without being able to discern it, it appears that the likely maximum sand concentration of approximately 5 ppg was approached during the first treatment.

D. Post Stimulation

1. Flow Back Procedures

The flow back procedure was initiated immediately following the removal of the stimulation hardware. The flow was restricted with a choke to enable the CO_2 vapor to flow safely. The choke size was increased as the pressure diminished and the CO_2 concentration was monitored. Some sand was produced as was expected because of the intentional under flush.

2. CO_2 Concentrations

The CO_2 concentrations were monitored following the stimulations and they diminished to a plateau of approximately 5.5%. Two of the wells reached this level during the third day and the other, #1021 by the sixth - or possibly the fifth (no measurement was taken that day). As would be expected, the CO_2 concentration during the flow back was related to the CO_2 volume.

CO_2 Concentrations During Flowback											
Well	Stimulated	CO_2(l) Tons	CO_2(v) MMcf	Day #2	Day #3	Day #4	Day #5	Day #6	Day #7	Day #8	Day #9
1021	07/14/98	103	1.77			10.0		5.0		5.5	5.6
1020	07/15/98	86	1.48		5.0		2.6		3.6	5.5	
1019	07/16/98	62	1.07	6.3		2.3		5.5	5.5		

3. <u>Cleaning Frac Sand from the Well Bore</u>

WBI's standard operating procedures immediately following the stimulation are to confirm that the well bore is free of any frac sand or other debris.

This activity is generally achieved by circulating air with some minor volume of surfactant through coiled tubing which is run to a depth below the perforations.

Following the stimulations both the candidate and control wells were all cleaned in this manner. The three candidate wells were as is generally the case with the CO_2/sand stimulations - because of the designed under flush, were found to have sand in them across the perforations. It was circulated from the well bore to a total depth considerably below the perforated interval.

Well	Perf Intvl (ft)	Depth-Top Perf (ft)	Sand Top (ft)	Fill-up (ft)	Clean Out Depth (ft)
1019	984-994	984	984	0	1148
1020	975-985	975	984	9	1156
1021	970-980	970	970	0	1165

It is note worthy that the sand left in the well bores was produced during the flow back. There was very little sand found above the top perforation in any of the wells, including the well which did screen out, 1019 which had an estimated 300 feet of sand in it.

After being placed in production the candidate wells did temporarily produce some minor volumes of sand. It is suspected that this small quantity is from loose sand either within or near the well bore.

4. Pressure Measurement and Drawdown Testing

Prior to being placed in production each well was isochronously back pressure tested (four point) with one-hour flow periods and a then a stabilized flow obtained - in approximately 20 hrs. The results were:

Well	Initial Well Head Pressure	AOF	@ Hrs	n	Gas Vented	Drawdown	Stim Type
	(psia)	(Mscfd)			(Mscf)	(%)	
1013	251.8	835	24	1.05	835	30.0	N_2 Foam
1014	348.2	400	24	1.03	393	45.0	N_2 Foam
1015	234.0	830	22	1.30	561	33.7	N_2 Foam
1017	342.6	420	20	1.40	420	33.5	N_2 Foam
1018	252.2	1018	20	1.15	743	38.3	N_2 Foam
1019	228.6	800	20	1.30	487	33.6	CO_2/Sand
1020	206.4	630	20	1.25	476	30.0	CO_2/Sand
1021	214.4	900	20	0.88	541	34.0	CO_2/Sand
1022	240.5	1070	20	1.50	782	31.6	N_2 Foam
1023							N_2 Foam

Because of the lower than anticipated production test results and a suspicion that possibly the extent of draw down may be a contributing factor, they were retested to determine if the tests were representative.

Well	Initial Well Head Pressure	AOF	@ Hrs	n	Gas Vented	Drawdown	Stim Type
	(psia)	(Mscfd)			(Mscf)	(%)	
1019	249.5	660	21	0.81	415	40.8	CO_2/Sand
1020	231.8	840	21	1.02	545	35.9	CO_2/Sand
1021	234.1	780	24	0.87	548	36.3	CO_2/Sand

There were some changes, probably as note worthy as any, is the observation that the initial wellhead pressure was greater than it had been for the first test. This is difficult to explain because there was no liquid introduced into the reservoir, other than the CO_2 which may not have totally vaporized at the time of the first test.

However, if it did remain the low viscosity would not be expected to significantly reduce the reservoir pressure.

E. Tubing Installation

Initial attempts to install 1.75 inch poly tubing (ID = 1.125in) in the three candidate wells immediately following the stimulations was unsuccessful because the production rate was too great. Consequently, the three wells which were stimulated with CO_2/sand produced for nine months without tubing whereas the other wells produced with tubing installed - to remove any liquids. There was a concern that the production from the untubed candidate wells may have been restricted and thereby influencing the production comparisons. WBI's field practices include the installation of tubing.

The three wells 1019, 1020, and 1021 were checked for sand bridges, liquid fill up, etc with coiled tubing and plastic poly-tubing was then installed in each on July 23,1999.

The production response for the remainder of the month was monitored and two of the three wells returned to their original production rate. Plots summarizing the production rates both before and after the tubing installation are attached. (Figures 15-17). One of the wells, #1020, initially appeared to be producing at a higher rate. Subsequent monitoring indicated that the production rate may have been improved by a statistically insignificant value (Figure 16).

Figure 15

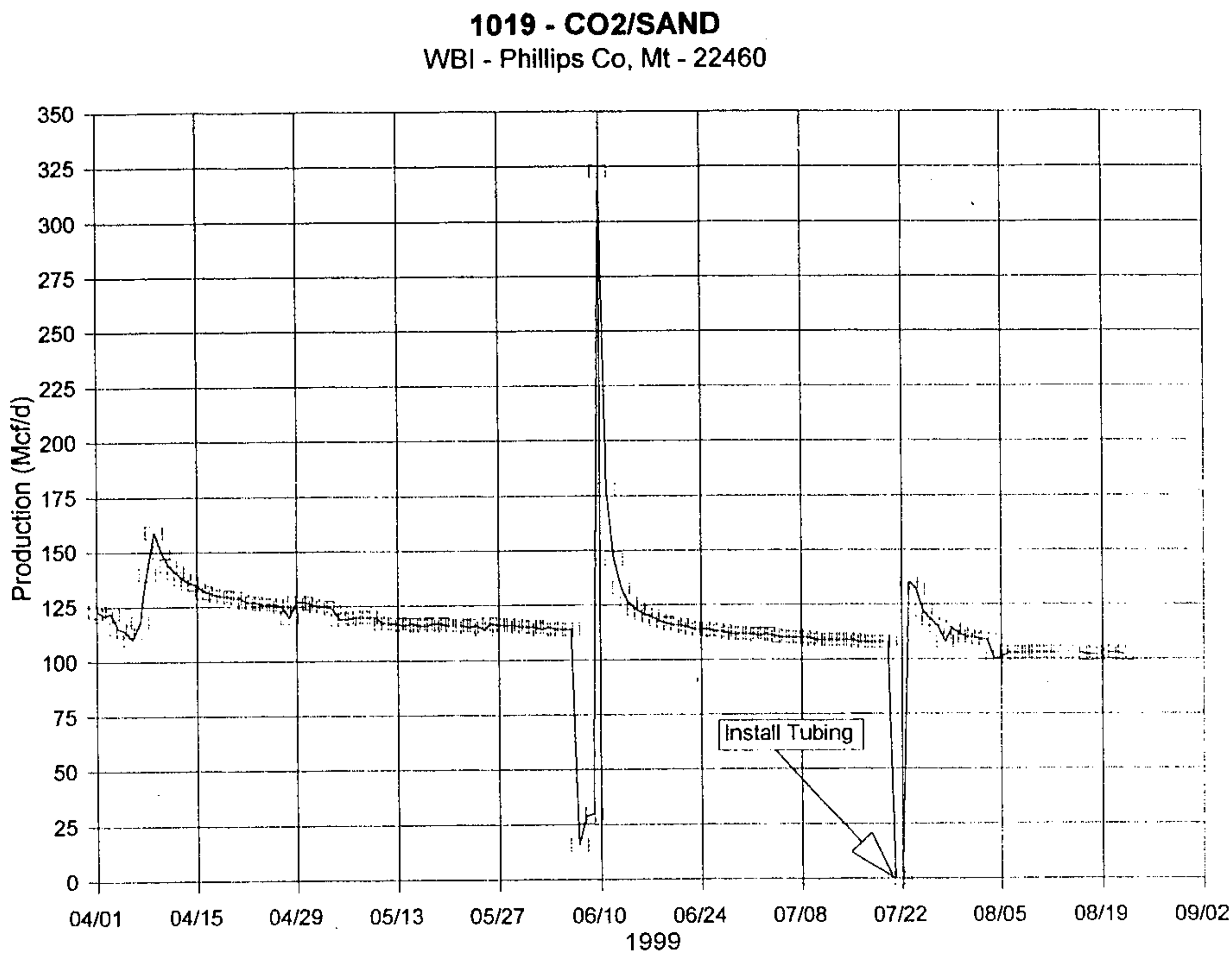

1019 - CO2/SAND
WBI - Phillips Co, Mt - 22460
Production (Mcf/d)
350
325
300
275
250
225
200
175
150
125
100
75
50
25
0
Install Tubing
04/01
04/15
04/29
05/13
05/27
06/10
06/24
07/08
07/22
08/05
08/19
09/02
1999

Figure 16

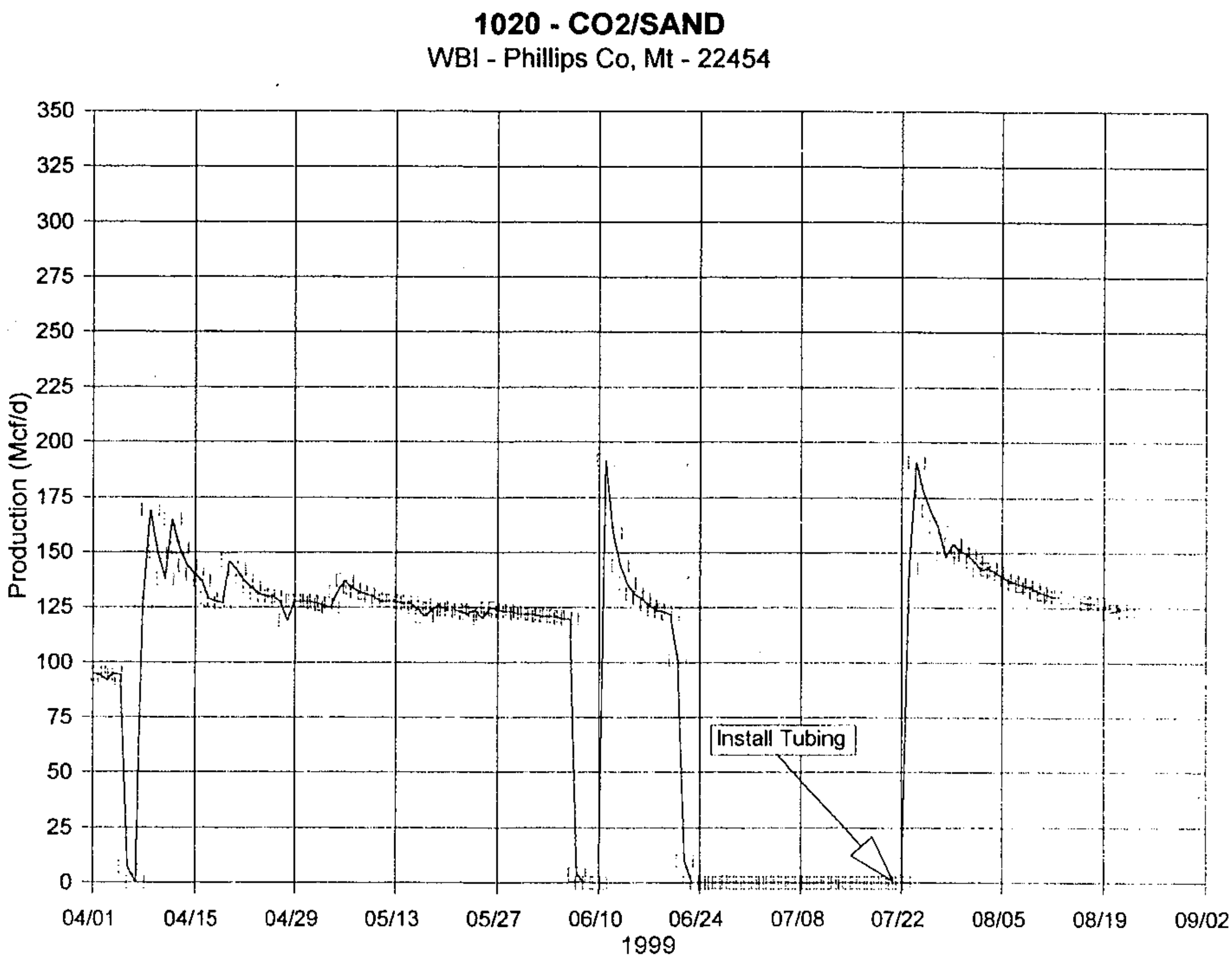
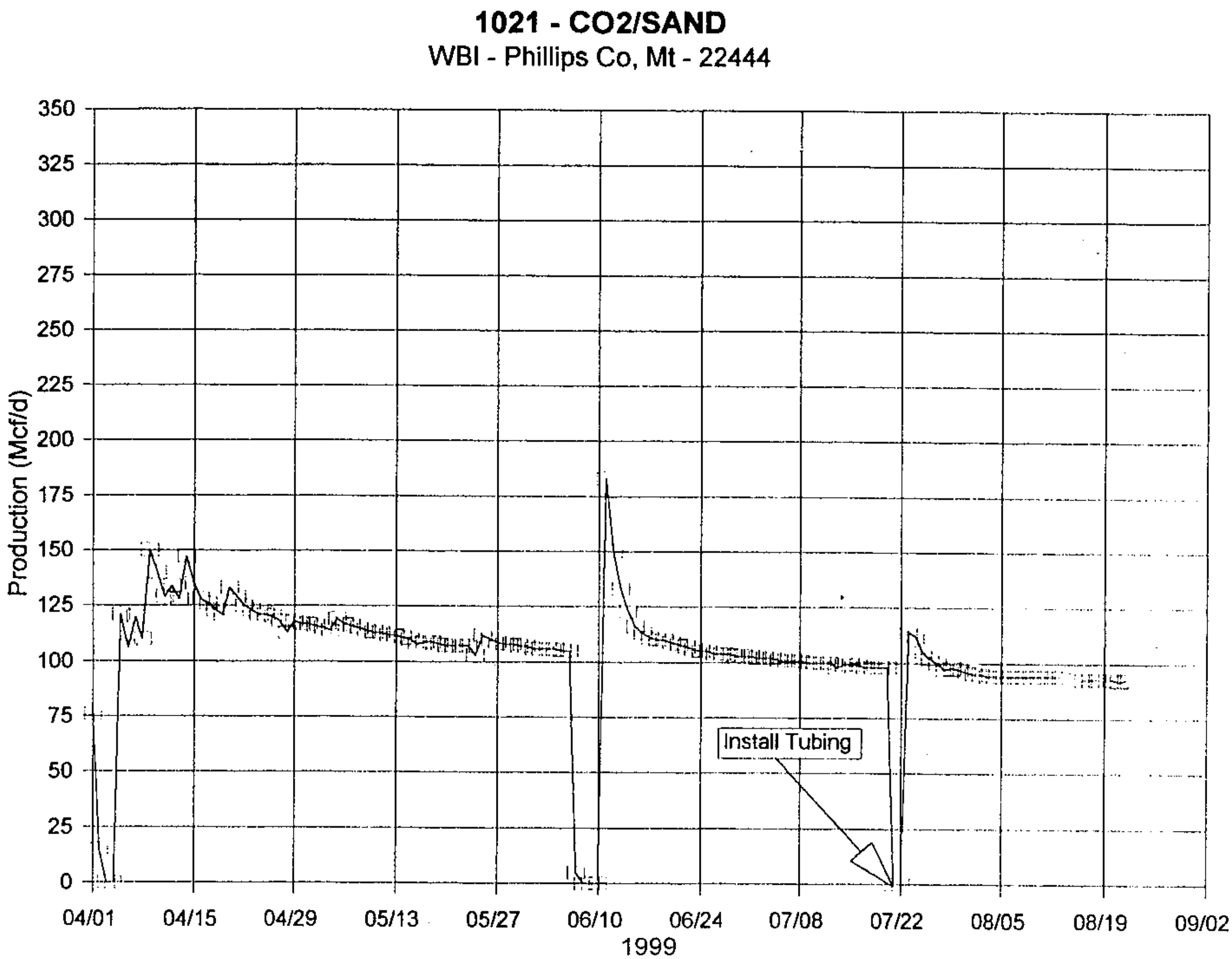

1020 - CO2/SAND
WBI - Phillips Co, Mt - 22454
Production (Mcf/d)
350
325
300
275
250
225
200
175
150
125
100
75
50
25
0
Install Tubing
04/01
04/15
04/29
05/13
05/27
06/10
06/24
07/08
07/22
08/05
08/19
09/02
1999

Figure 17


1021 - CO2/SAND
WBI - Phillips Co, Mt - 22444
Production (Mcf/d)
350
325
300
275
250
225
200
175
150
125
100
75
50
25
0
Install Tubing
04/01
04/15
04/29
05/13
05/27
06/10
06/24
07/08
07/22
08/05
08/19
09/02
1999

The installation of tubing in two of the wells stimulated with CO_2/sand, #1019 and #1021 did not improve the production rate, and therefore the production rate data is considered valid and that an objective comparison of the two stimulation types can be made for these two wells. The production rate from the only other well stimulated with CO_2/sand, #1020 may have been slightly improved but so slightly that no, if any economic benefit resulted.

XVI. COSTS

A. Wellhead Isolation Tool

After discussing the CO_2/sand stimulations with Fracmaster, WBI concluded that a wellhead isolation tool should also be incorporated with the treatments. Upon WBI's request the DOE was requested to bear one-half of the cost of the wellhead isolation tool services.

After discussions with the DOE they concurred and agreed to bear one-half of the cost. A Canadian company familiar with sealing at the colder than normal temperatures, of the liquid CO_2 was contacted and the scheduling arranged by Fracmaster. The projected cost of the wellhead isolation services was $6,343.00 as a minimum, and included as many as three wells.

B. Pumping Services

1. Projected - The projected costs for stimulating these wells with CO_2/sand was:
2.

Equipment	$16,053.79
Materials	35,957.65
CO_2	incl
	52,011.44
Computer Control	1,080.00
Report	427.50
	53,518.94
3 Wells	160,556.82
Mobilization	17,500.00
	178,056.82
Per Well (÷ 3)	59,352.27
Cost to WBI	29,676.14
Cost to DOE	29,676.13
	$59,352.27

Presuming that no standby charges were incurred, then the charge for stimulating the three candidate wells was projected to be $178,056.82 [(3x53,518.94) + 17,500.00].

Excluding any subsistence charges, the cost to the project for the CO_2/sand stimulations, excluding the well head isolation tool was projected to be $89,028.42 for both WBI and the DOE or $29,676.14 per well — or a total projected per-well cost of $59,352.27.

3. Actual

The actual costs for the CO_2/sand stimulations were:

Well	Stimulation	Isolation Tool	Total
1019	52,223.00	2,181.00	54,404.00
1020	52,283.33	2,181.00	54,464.33
1021	57,364.77	2,181.00	59,545.77
Totals	161,871.10	6,543.00	168,414.10

4. Projected vs Actual

The actual costs for the treatments was less than projected primarily because of reduced CO_2 volumes as a result of the accelerated sand schedules.

Costs	Stimulation	Isolation Tool	Total
Projected	178,056.82	6,333.00	184,389.82
Actual	161,871.10	6,543.00	168,414.10
Differences	(16,185.72)	210.00	(15,975.72)

XVII. RESULTS

A. Production Comparisons

The twenty-four month production is plotted for the ten new wells, 1013 through 1023 - excluding 1016 which was not drilled (Figures 18-27 - following their respective tables below) and tabulated and compared with the previously drilled control wells as follows.

It is readily apparent that the cumulative gas production for months two through thirteen from all of the new wells, drilled within the control area in 1998 are less than those drilled previously. Consequently the production has been tabulated in three stimulation type groups:

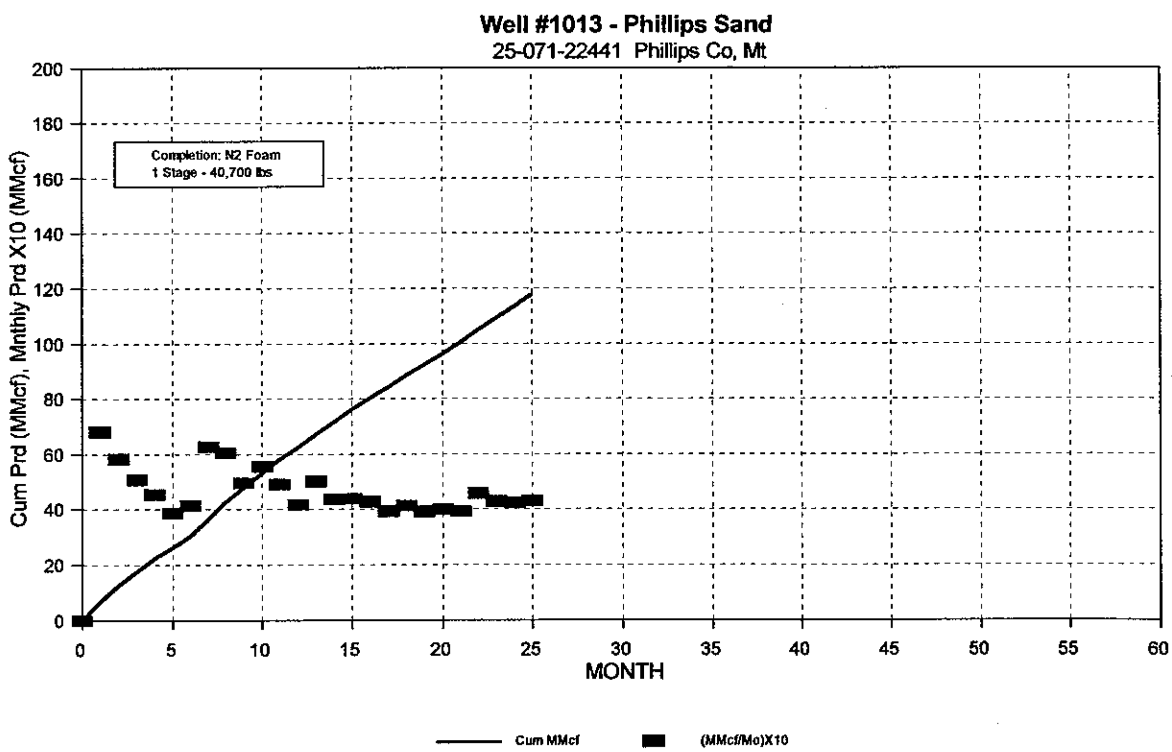
1. N_2 Foam - Pre July 1998 (Control Wells)
2. N_2 Foam - July 1998 (Control Wells)
3. CO_2/Sand - July 1998 (Candidate Wells)

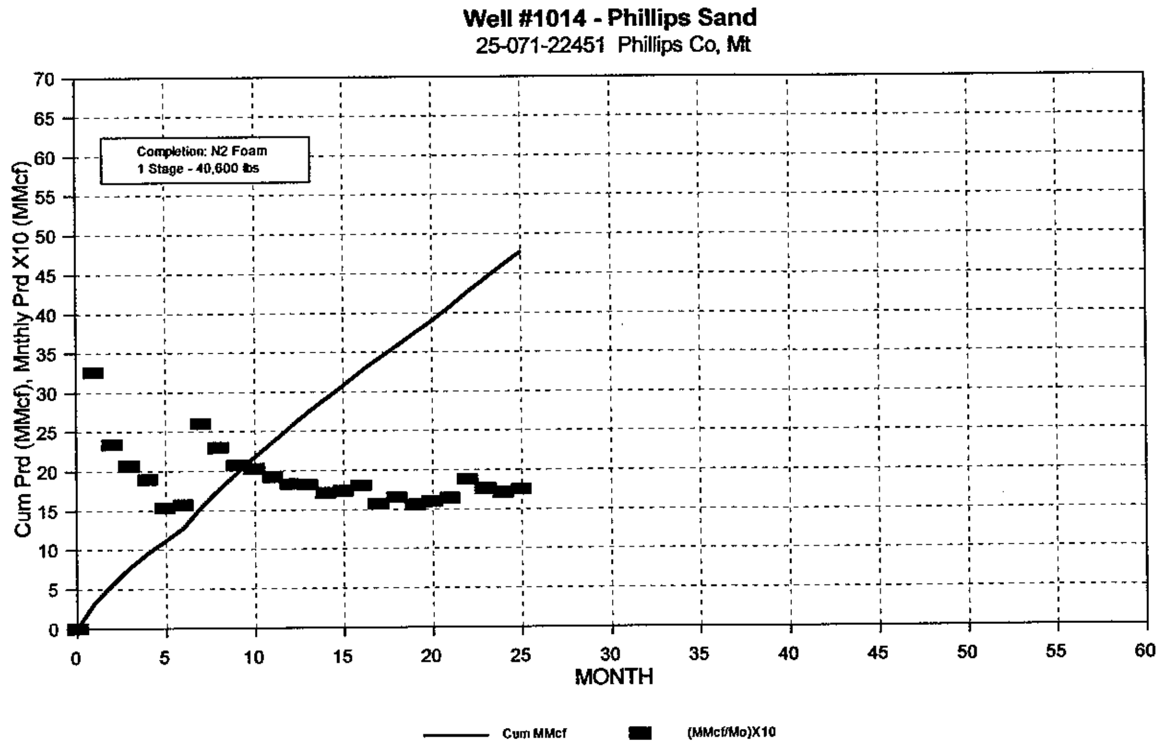
Group #1- Pre July 1998 (Control Wells)

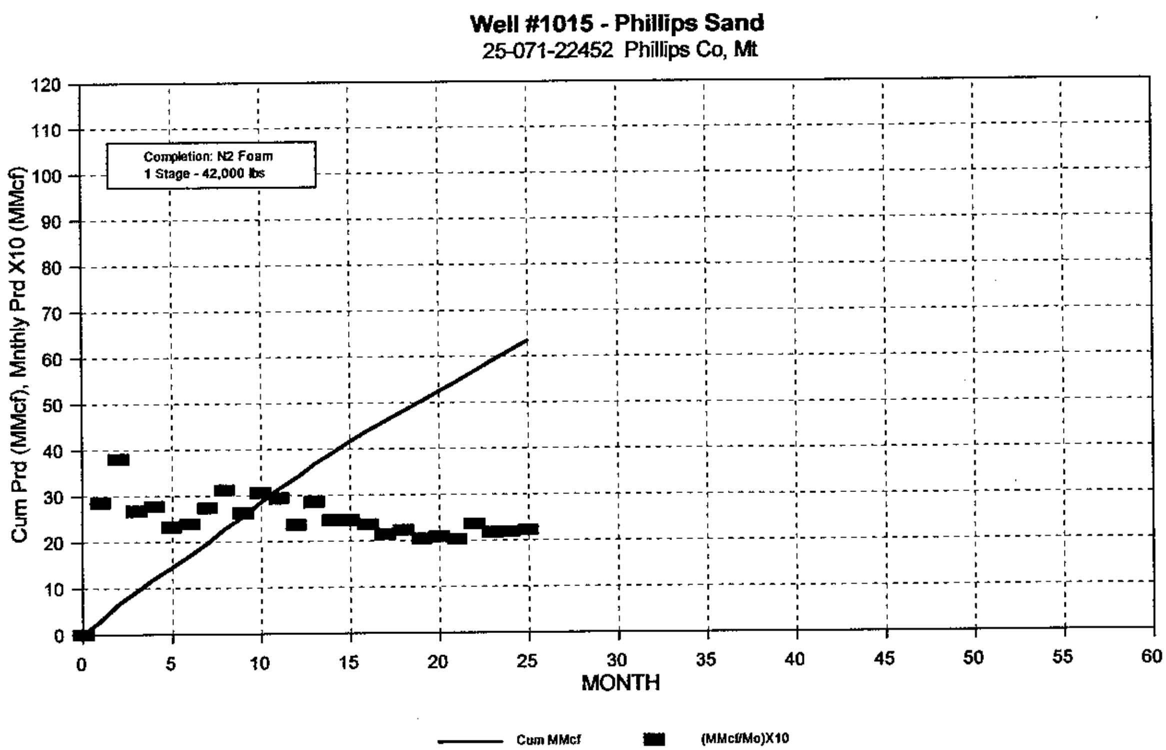
Control Wells (N_2 Foam)								
Existing Wells (Stimulated Prior to 07/98)								
					API #	Cum Prod (MMcf)		
Well #	Twp	Rge	Sec	Quad	25-071-	Month 2	Month 13	Month 2-13
972	33N	32E	27	NW	22267	1.046	25.433	24.387
973	33N	32E	32	SE	22268	1.187	80.759	79.572
974	33N	32E	33	NE	22269	0.874	55.875	55.001
976	33N	32E	35	NW	22272	0.441	56.654	56.213
990	32N	32E	02	NW	22275	12.699	83.790	71.091
991	32N	32E	01	NE	22279	9.158	63.894	54.736
997	33N	32E	32	NE	22287	?????	32.568	32.568
1000	32N	32E	02	SE	22283	10.880	71.401	60.521
1002	33N	32E	33	SE	22288	9.671	66.678	57.007
							Avg (n=8)	57.316

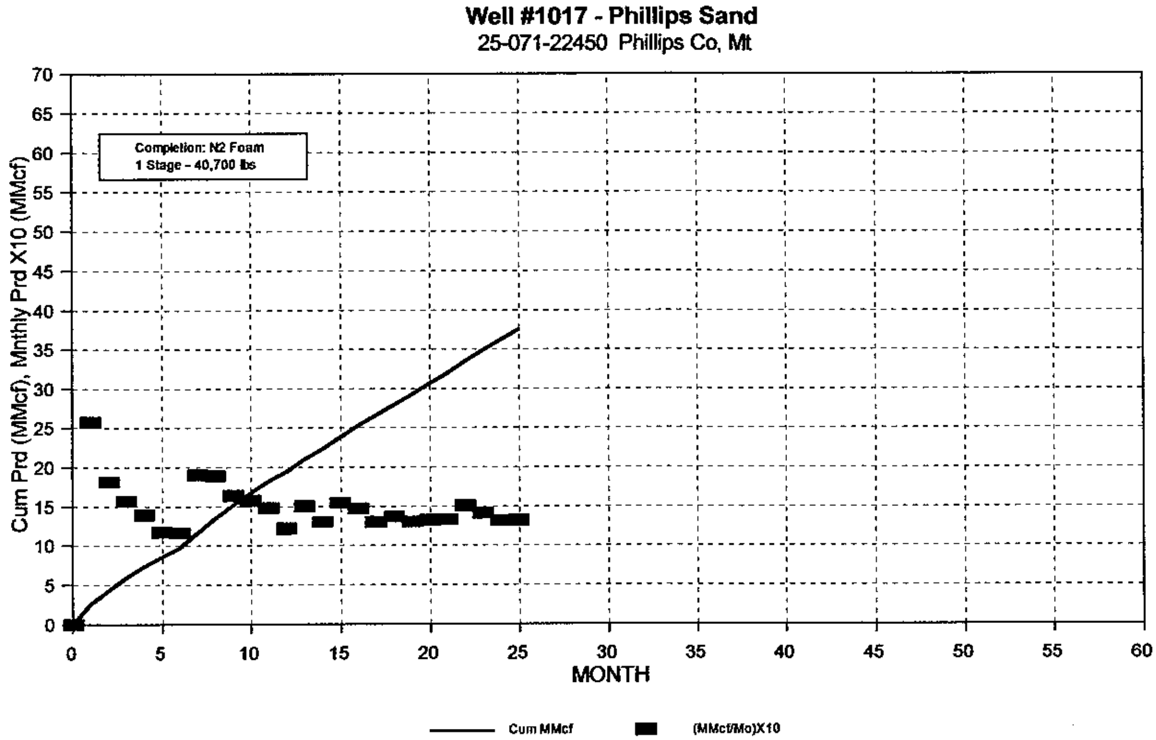
Group #2 - July 1998 (Control Wells)

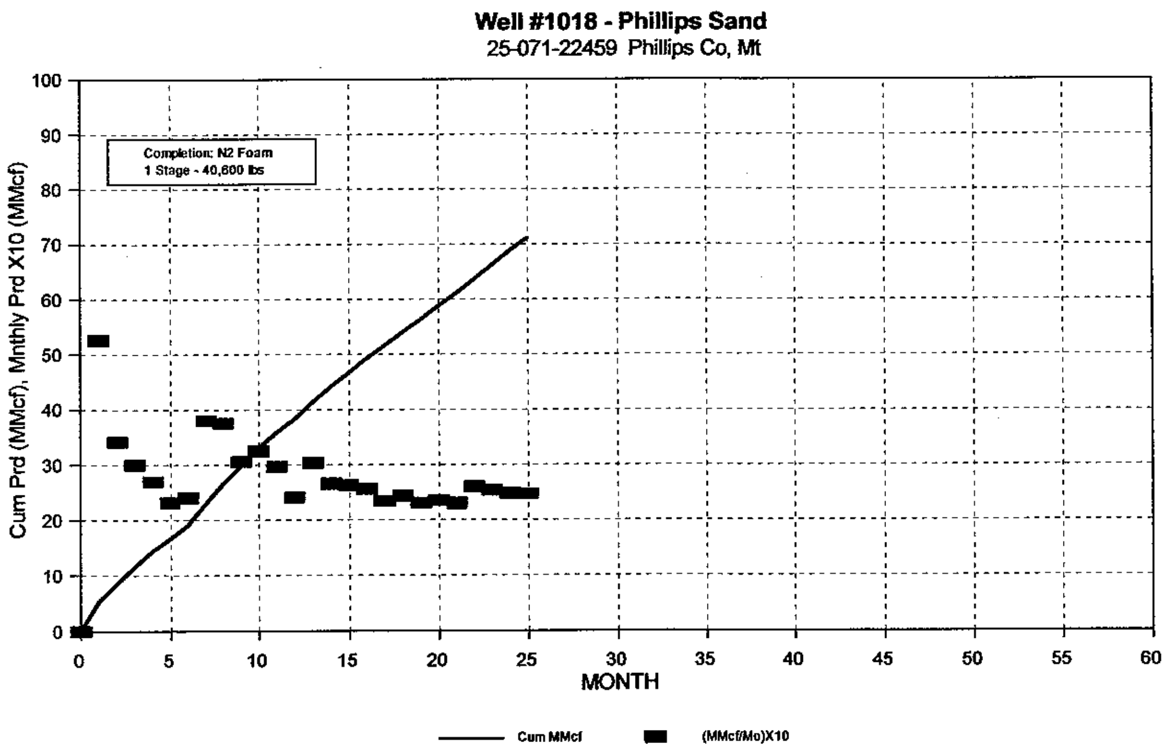
New Wells (N_2 Foam) (Stimulated 07/98)								
					API #	Cum Prod (MMcf)		
Well #	Twp	Rge	Sec	Quad	25-071-	Month 2	Month 13	Month 2-13
1013	32N	32E	03	NW	22441	12.659	67.343	54.684
1014	33N	32E	31	NE	22451	5.605	27.293	21.688
1015	33N	32E	29	NW	22452	6.671	36.595	29.924
1016	33N	32E	28	SE	Not Drld			
1017	33N	32E	27	SW	22450	4.402	20.957	16.555
1018	33N	32E	34	NE	22459	8.691	41.413	32.722
1022	32N	32E	12	NE	22445	10.701	53.952	43.251
1023	32N	32E	13	SE	22446	8.447	41.093	32.646
							Avg (n=7)	33.067

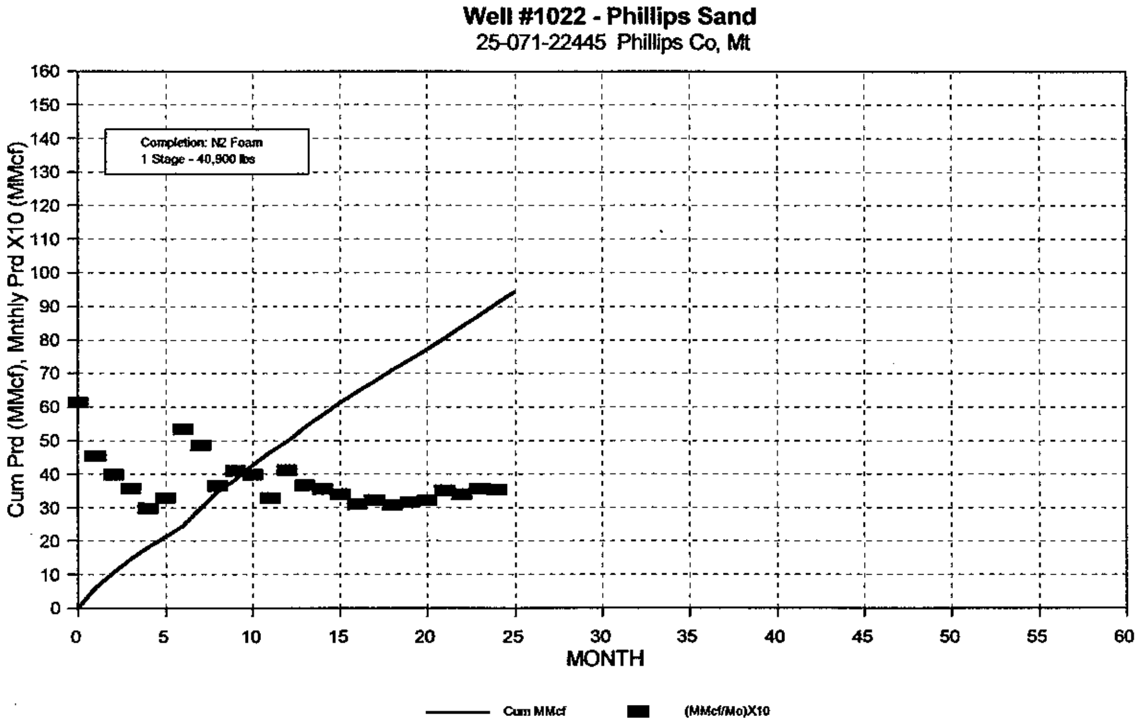


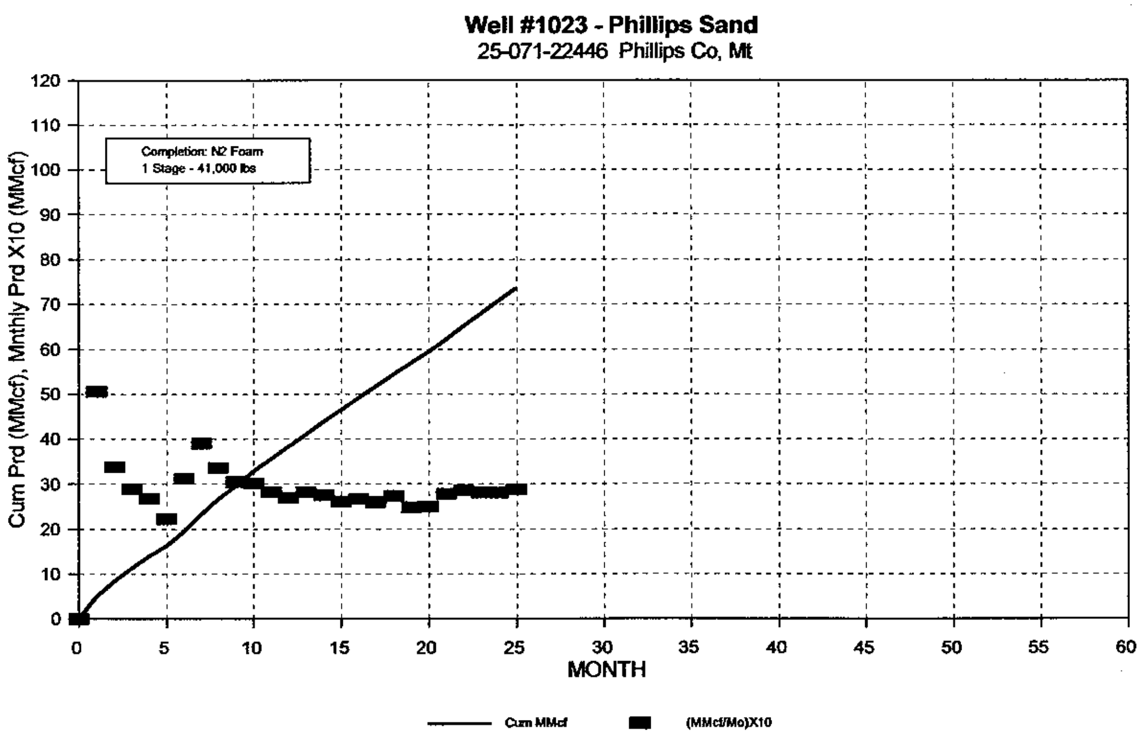

Well #1014 - Phillips Sand
25-071-22451 Phillips Co, Mt
Completion: N2 Foam
1 Stage - 40,600 lbs
Cum Prd (MMcf), Mnthly Prd X10 (MMcf)
MONTH
Cum MMcf
(MMcf/Mo)X10


Well #1015 - Phillips Sand
25-071-22452 Phillips Co, Mt
Completion: N2 Foam
1 Stage - 42,000 lbs
Cum Prd (MMcf), Mnthly Prd X10 (MMcf)
MONTH
Cum MMcf
(MMcf/Mo)X10


Well #1017 - Phillips Sand
25-071-22450 Phillips Co, Mt
Completion: N2 Foam
1 Stage - 40,700 lbs
Cum Prd (MMcf), Mnthly Prd X10 (MMcf)
MONTH
Cum MMcf
(MMcf/Mo)X10

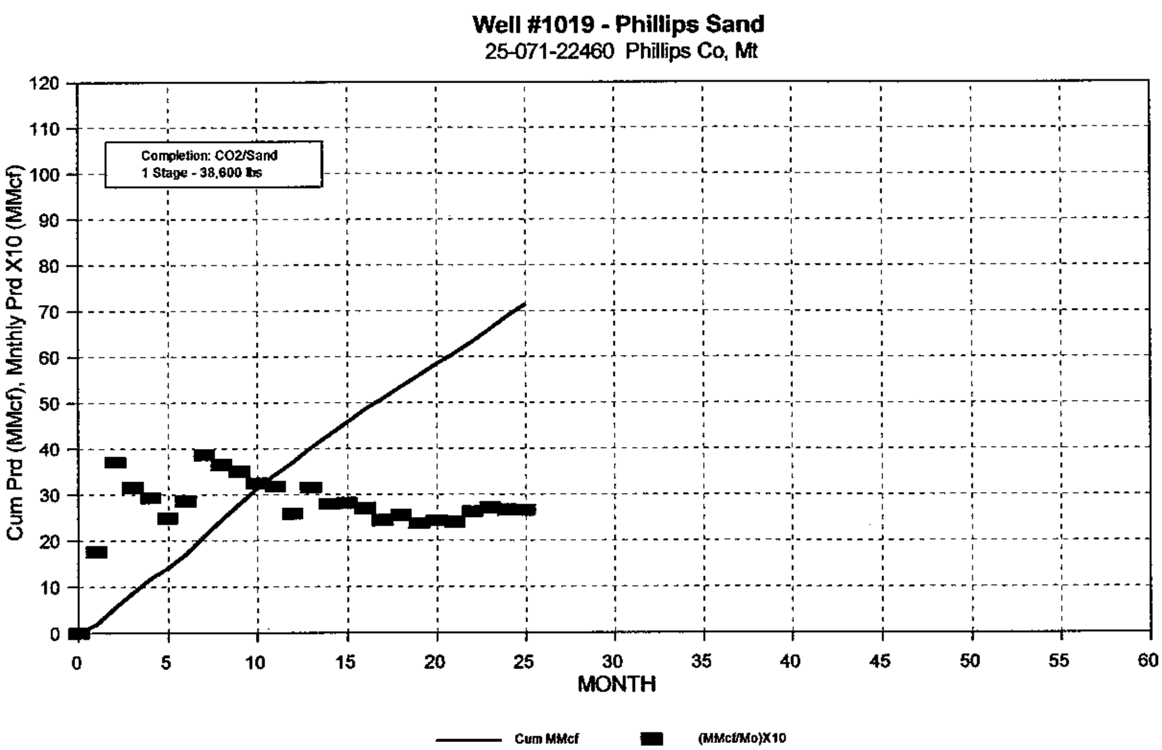

Well #1018 - Phillips Sand
25-071-22459 Phillips Co, Mt
Completion: N2 Foam
1 Stage - 40,600 lbs
Cum Prd (MMcf), Mnthly Prd X10 (MMcf)
MONTH
Cum MMcf
(MMcf/Mo)X10


Well #1022 - Phillips Sand
25-071-22445 Phillips Co, Mt
Completion: N2 Foam
1 Stage - 40,900 lbs
Cum Prd (MMcf), Mnthly Prd X10 (MMcf)
MONTH
Cum MMcf
(MMcf/Mo)X10

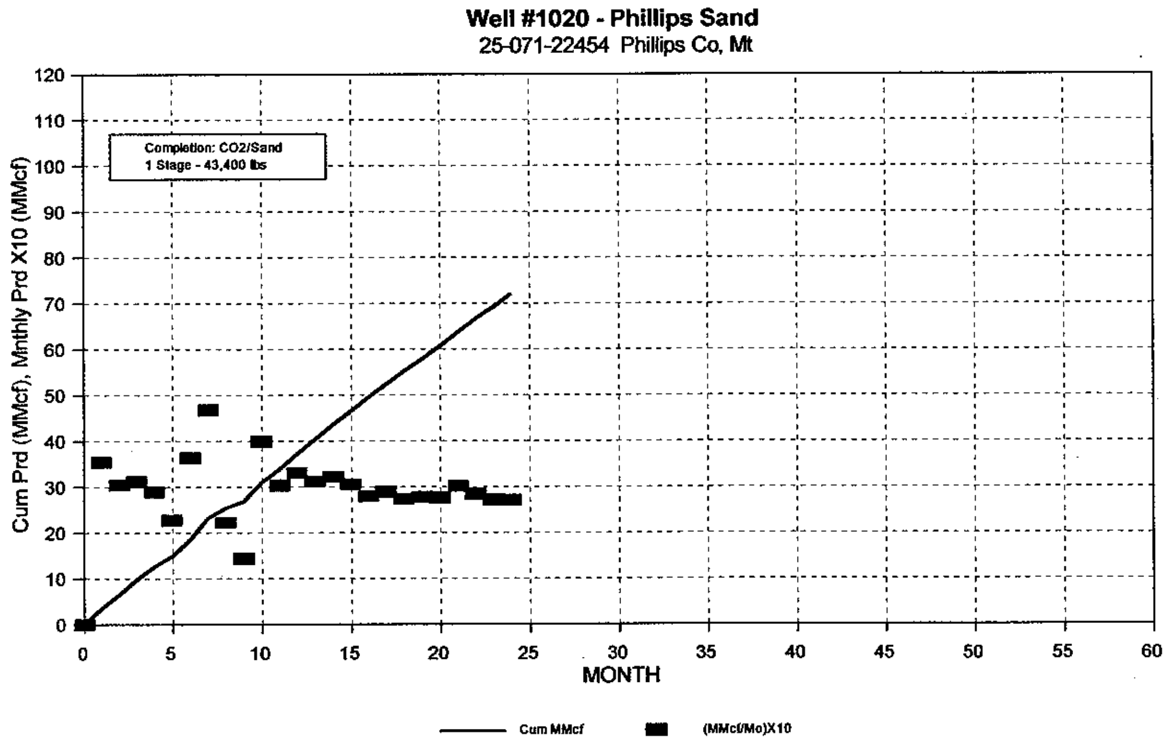

Well #1023 - Phillips Sand
25-071-22446 Phillips Co, Mt
Completion: N2 Foam
1 Stage - 41,000 lbs
Cum Prd (MMcf), Mnthly Prd X10 (MMcf)
MONTH
Cum MMcf
(MMcf/Mo)X10

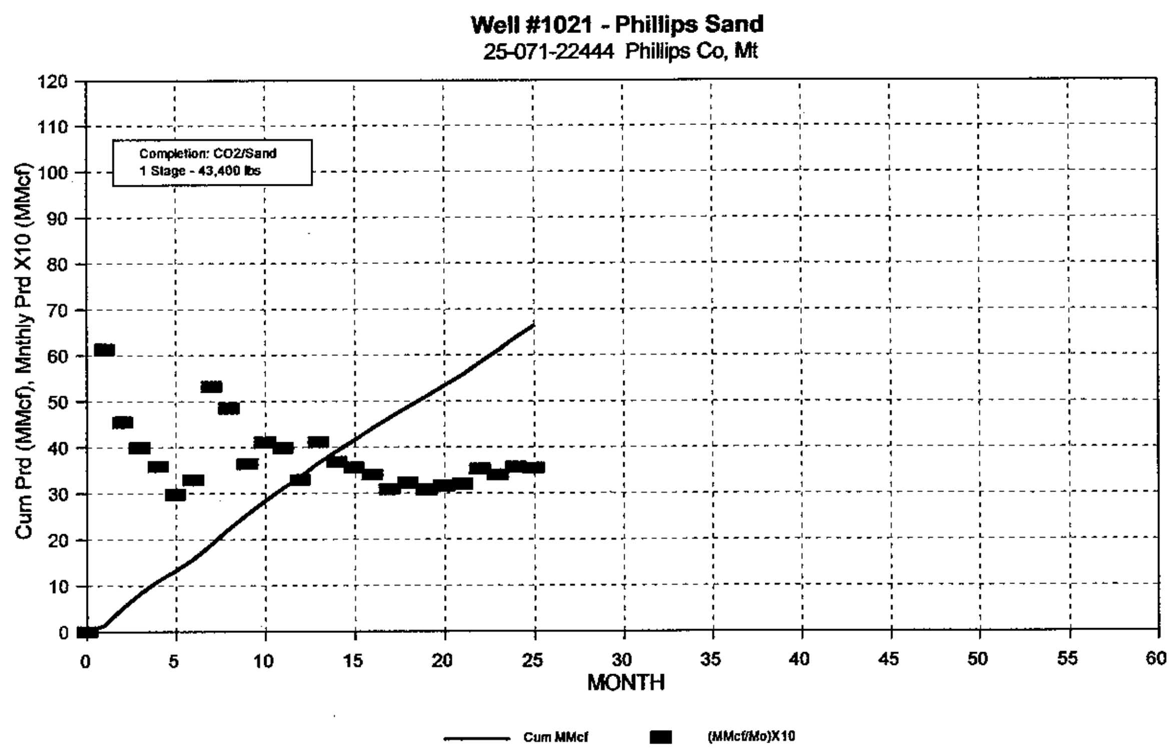
Group #3- July 1998 (Candidate Wells)

Candidate Wells (CO_2/Sand)(Stimulated 07/98)								
					API #	Cum Prod (MMcf)		
Well #	Twp	Rge	Sec	Quad	25-071-	Month 2	Month 13	Month 2-13
1019	33N	32E	34	SE	22460	5.473	40.178	34.705
1020	32N	32E	01	NW	22454	6.601	40.376	33.775
1021	32N	32E	12	NW	22244	5.164	36.520	31.356
							Avg (n=3)	33.270



Final Report - Group #5 – Demonstration of CO_2/Sand Stimulations in Three Candidate Wells (Phillips Co, Montana) – July 1998 – Single Stage Treatments – WBI
Contract #DE-AC21-94MC31199 – "Field Testing & Optimization of CO_2/Sand Fracturing Technology"

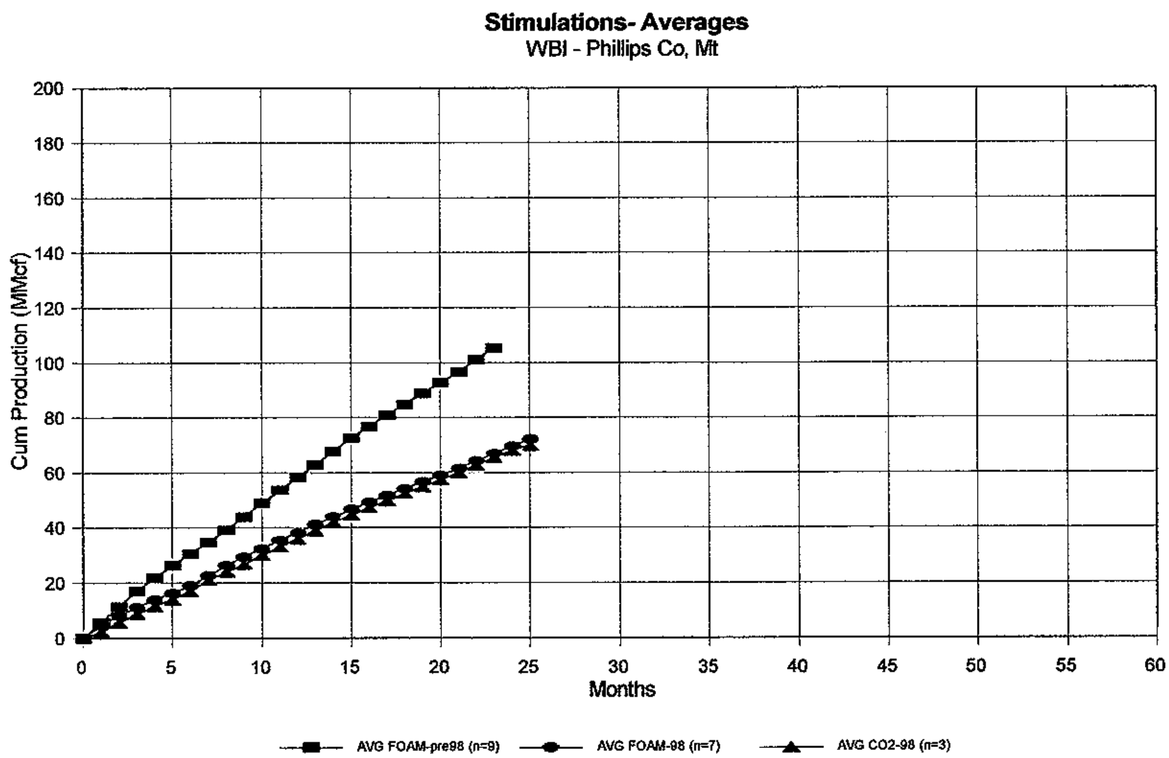




The average cumulative gas productions from each of these groups has been plotted (Figure 28) and it dramatically indicates the superiority of the production from the pre 98 wells. The cumulative production averages from both of the 98 Control (Group 2) and Candidate wells (Group 3) are identical and considerably less than those drilled prior to 98 (Group 1).

It was determined later that the reduced production from the wells completed after 1998 was a result of reduced well spacing and reduced reservoir pressure.

Figure 28

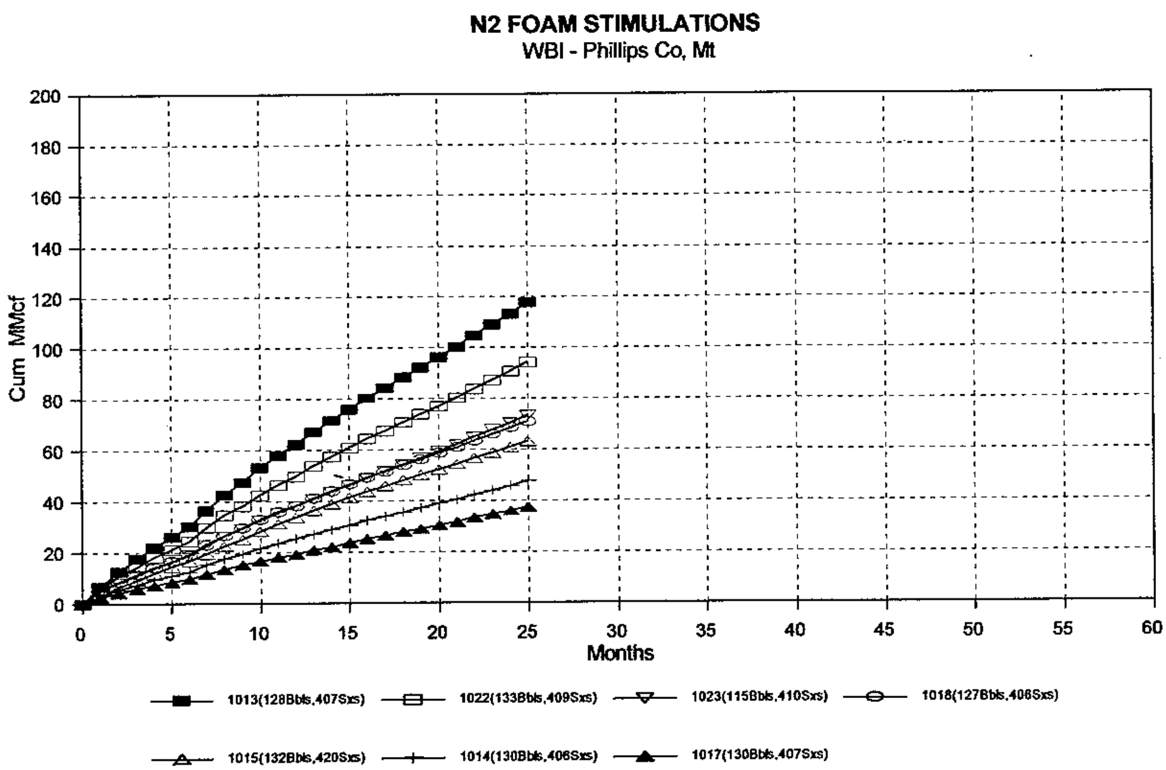


Some possible explanations as to why the production from the newer wells was less than that from the wells drilled prior to 1998 are:

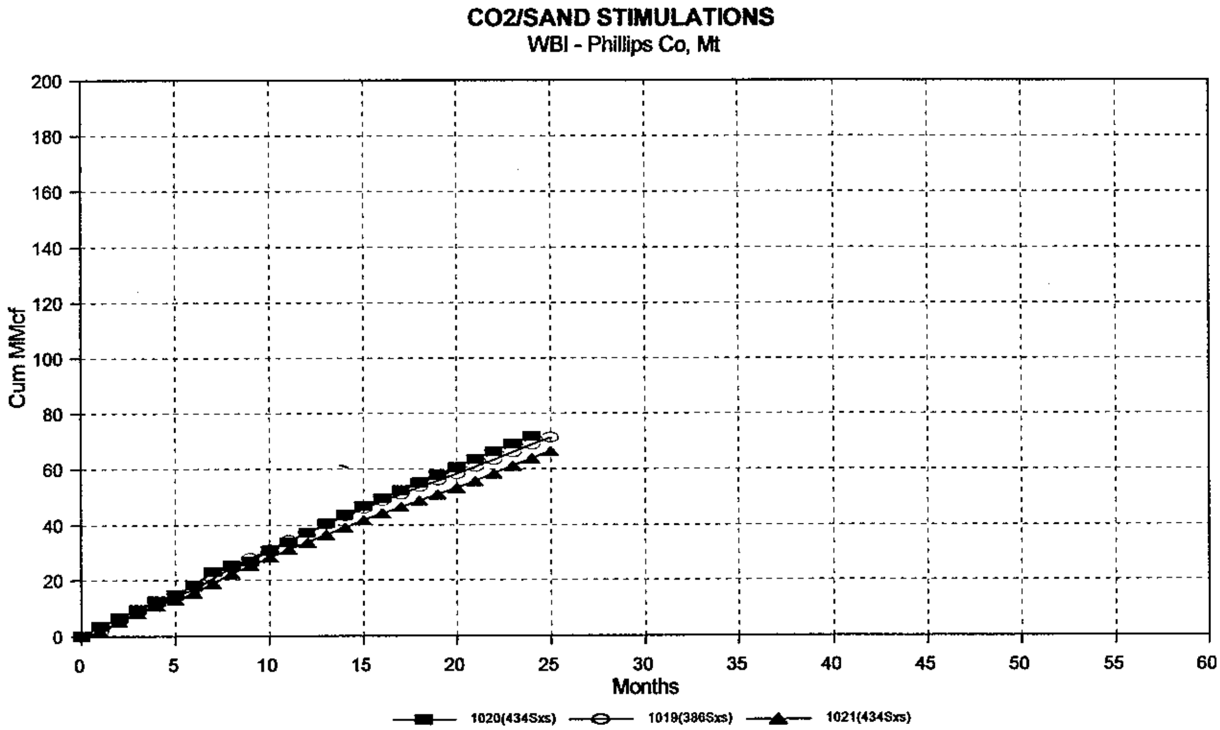
- o The reservoir pressure has diminished.
- o The revised perforation strategy has resulted in the reduction in the cumulative production.

The production for groups 1-3 are also plotted as follows:

- o Group 2 (N_2 Foam stimulated Candidate Wells drilled in 1998) - Figure 29



- Group 3 (CO_2/sand stimulated Control Wells drilled in 1998) - Figure 30



It is perhaps more apparent from these plots then it is from the tabulated data that:

- There is considerably more variance in the cumulative production volumes from the wells stimulated with N_2 Foam (Figure 29) then there is for the wells stimulated with CO_2/sand (Figure 30).

  This is an unexpected and unusual occurrence. In the past it has been observed that the wells which have been stimulated with CO_2/sand had significant variances in the production rate while the foam stimulated wells sometimes had practically no variance. This response was suspected to be a result of trapped stimulation liquids which were inhibiting the production. The good news is that because there is a large production variance from the wells which were stimulated with foam there is probably very limited, if any liquid phase trapping.

The thing that's difficult to understand is that there is practically no production variance between the three CO_2/sand stimulated wells.

A potential explanation is that the larger proppant size, 12/20 and greater sand concentration, 12 pounds per gallon utilized on the N_2 Foam stimulations may be offsetting proppant embedment? That is, that the smaller proppant (20/40) and the reduced proppant loading utilized for the CO_2/sand stimulations was resulting in a smaller propped fracture width.

o The production rate from the wells stimulated with CO_2/sand is essentially the same from all three wells.

The wells stimulated with CO_2/sand have always had significant variations in production, while those stimulated with foam have not sometimes they are essentially the same - especially in lower pressure reservoirs.

It is considered to be so unlikely that all three of the wells stimulated with CO_2/sand should have production rates that are essentially the same that it is suspected that these well are influenced by some production limiting mechanism.

Some thoughts were:

o There could be sand or other blockages in the well bore?
The well bores were subsequently checked and determined to be unobstructed. It was therefore suspected that the lack of variation in the cumulative production responses is a result of limited conductivity in the hydraulic fracture.

- That the larger proppant size and concentration utilized on the foam stimulations may be offsetting proppant embedment?

  The proppant size used on all seven of the N_2 Foam stimulations on the Control wells was the same size, 12/20 whereas the CO_2/sand stimulations utilized only the smaller 20/40 proppant

B. Production Comparisons-Projected vs Actual

The pre-test cumulative production projections were compared with the actual amounts and in all instances the actual production for months two through thirteen were considerably less than that projected. There does not appear to be any correlation between the stimulation type and these differences.

Well #	Cum Prod 2-16 (MMcf)	Projected (MMcf)	Diff (%)	StimType
1015	29.9	42	-29%	N_2 Foam
1017	16.6	42	-60%	N_2 Foam
1019	34.7	54	-36%	CO_2/Sand
1020	33.8	45	-25%	CO_2/Sand
1021	31.4	54	-42%	CO_2/Sand
1022	32.6	45	-28%	N_2 Foam
		Avg	-32%	

Well 1017 has the most drastic deviation between the actual and projected. It was one of the originally proposed candidate wells and was rejected primarily because of the projected reduction in sand thickness. It is also the most northerly well of the group and closest to the known dry hole area near the reservoir boundary. (Refer to the section on the Candidate Well Selection.

Other observations were:

- The monthly production rates from both the control wells (N_2 Foam) and the candidate wells (CO_2/sand) readily cleaned up following the stimulation, and specifically that the wells stimulated with N_2 Foam did not exhibit a reduced production rate or slow clean up period.

- Both groups of wells, control and candidate generally experienced a five month period of higher "flush production" rates.

C. Production Comparisons Beyond 13 Months

The 24 month cumulative production history is consistent with that reported earlier. The table is rank-ordered for the 2-13 month cumulative production volume. The initial observations continue to be substantiated although the top three cumulative production wells are now all N_2 Foam stimulations. Well #1023 has been moved up from the sixth best producer to third. Also, the production from two of the CO_2/sand stimulations, wells 1019 &1020 have exchanged the third and fourth positions.

Cumulative Production (MMcf)					
Well #	Mo 2	Mo 13	Mo 2-13	Mo 24	Stim Type
1013	12.659	67.343	54.684	113.436	N_2 Foam
1022	10.701	53.952	43.251	90.090	N_2 Foam
1019	5.473	40.178	34.705	68.727	CO_2/Sand
1020	6.601	40.376	33.775	71.940	CO_2/Sand
1018	8.691	41.413	32.722	68.653	N_2 Foam
1023	8.447	41.093	32.646	70.728	N_2 Foam
1021	5.164	36.520	31.356	63.800	CO_2/Sand
1015	6.671	36.595	29.924	61.165	N_2 Foam
1014	5.605	27.293	21.688	45.973	N_2 Foam
1017	4.402	20.957	16.555	36.275	N_2 Foam

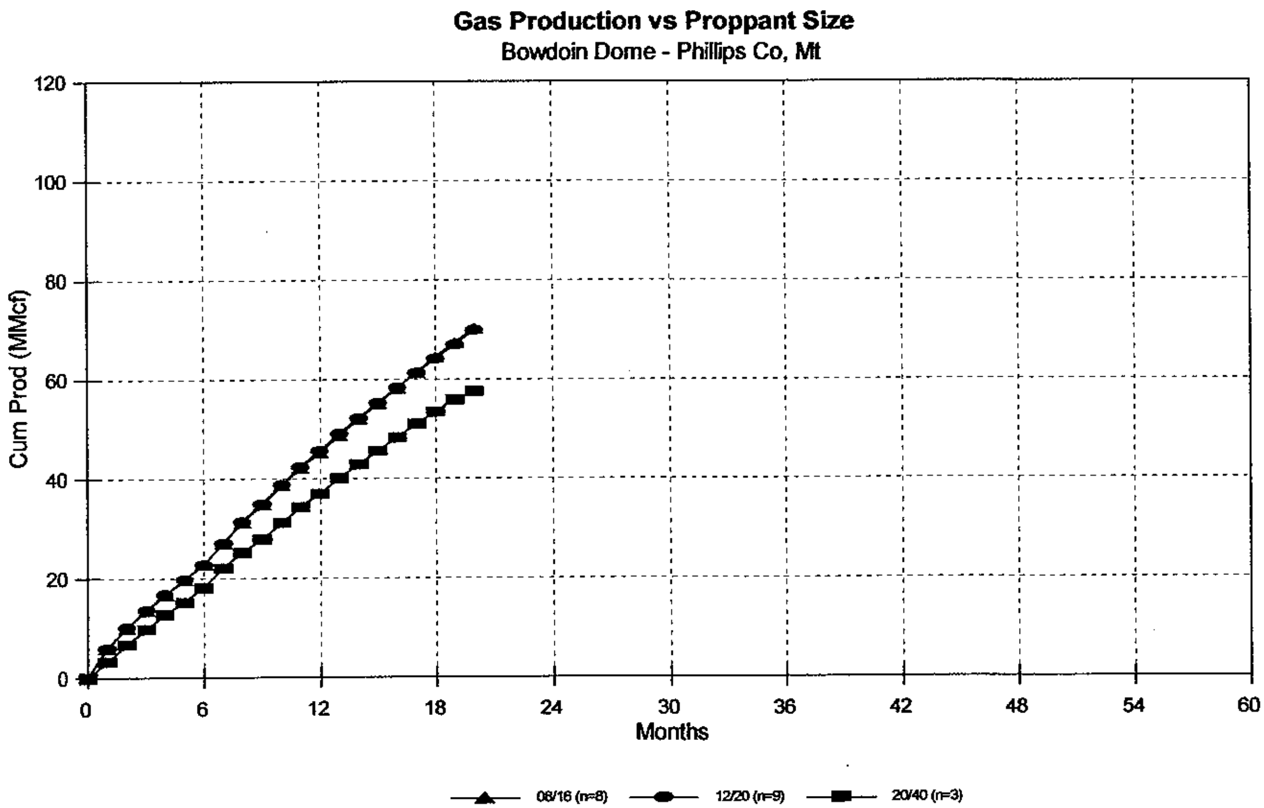
XVIII. PROPPANT SIZE

Because there is some question as to whether the size of the proppant utilized in the stimulations may impact the production rates a review of the different size proppants used in twenty wells within the Bowdoin Field was made. The cumulative production was compared by utilizing the following information:

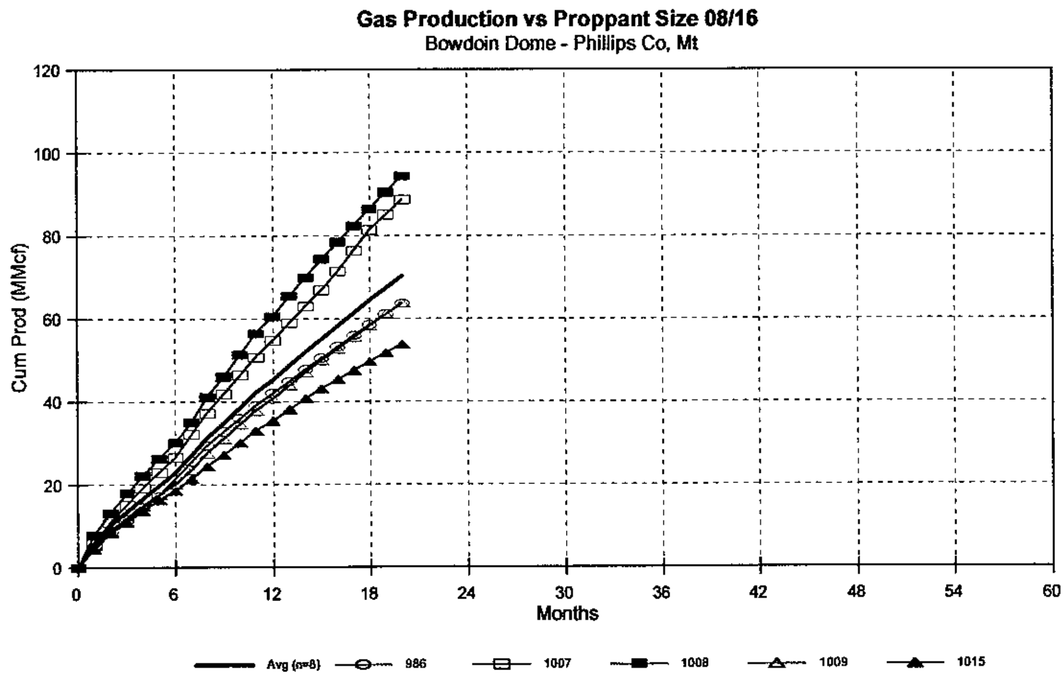
Number of Wells			
	Proppant Size		
Stim Type	08/16	12/20	20/40
N_2 Foam:	8	9	
CO_2/Sand:			3

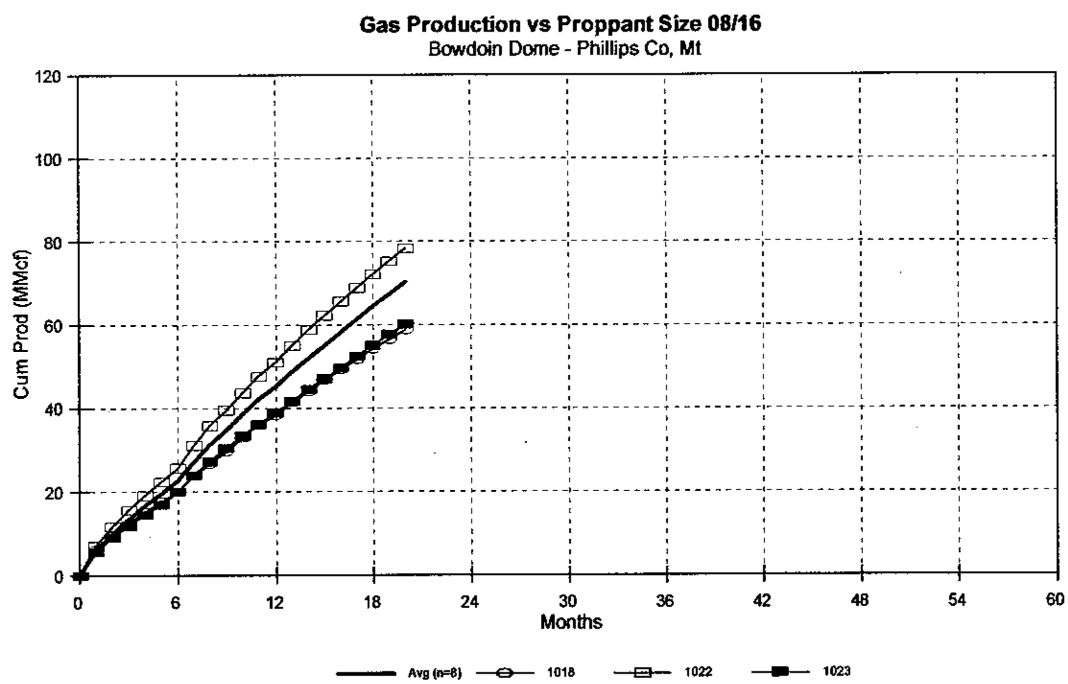
The twenty month cumulative production was plotted for each of these three groups:

- Average cumulative production from all three proppant sizes - Figure 31

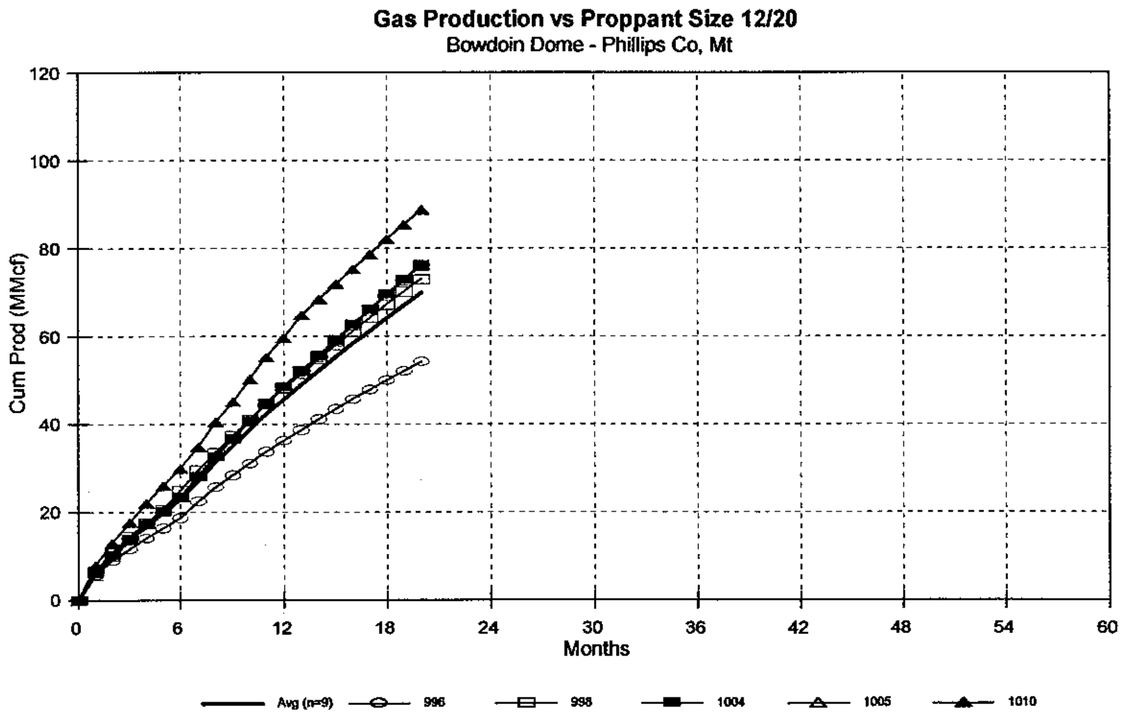


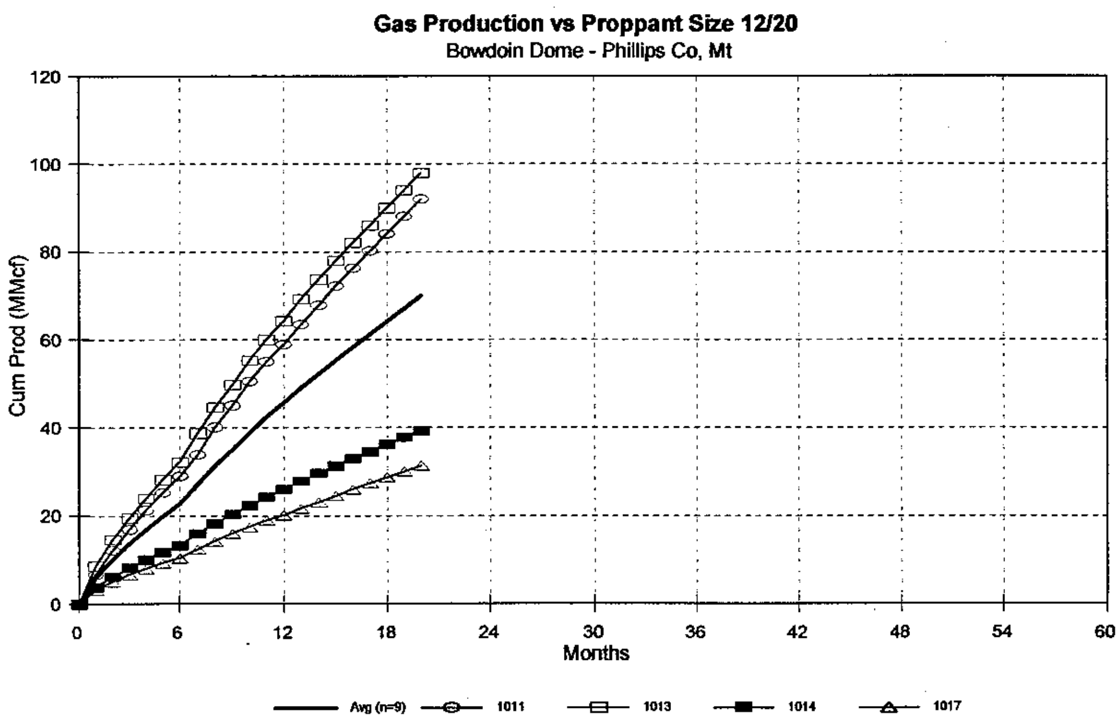
- 08/16 - Figures 32 and 33



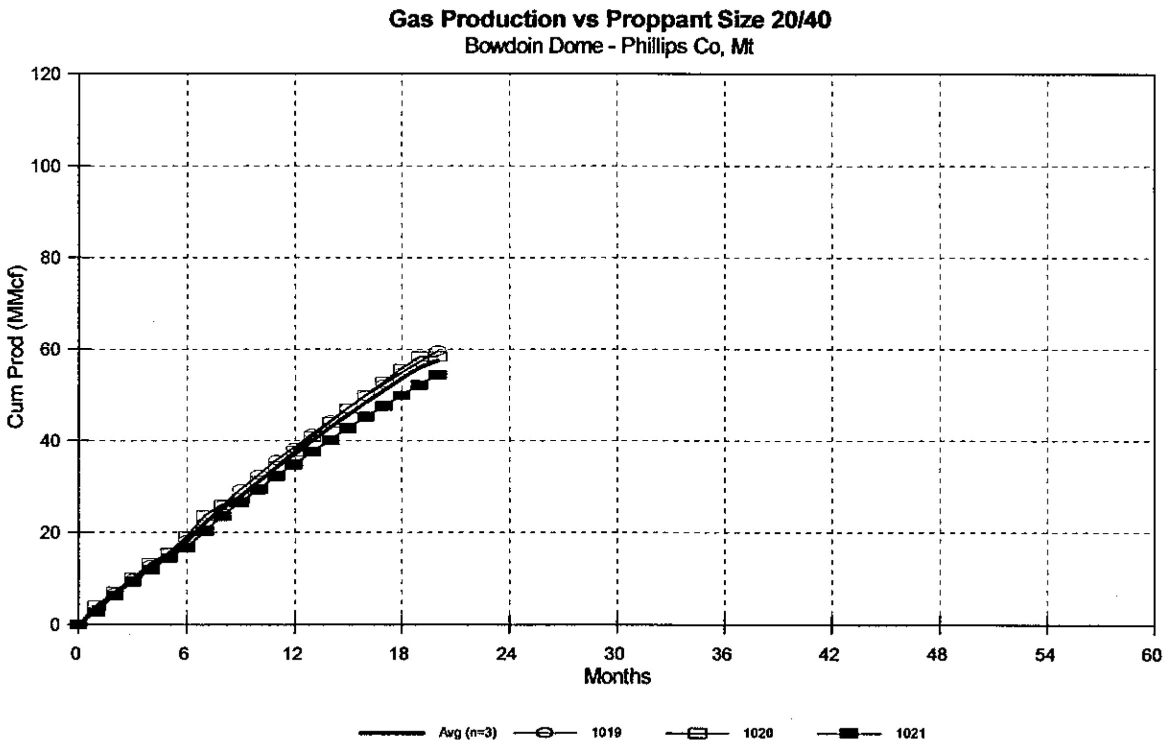


- 12/20 - Figures 34 and 35





o 20/40 - Figure 36



It is evident from these plots that:

- The cumulative production averages of the wells stimulated with 08/16 and 12/20 are identical (Figure 31),

- The cumulative production average of the three wells stimulated with 20/40 is obviously less than that of the two groups which employed the larger proppant sizes (Figure 31),

  There are only three wells in this group and they were also the only ones which were stimulated with CO_2/sand.

- The variance in the cumulative productions from the three wells stimulated with 20/40 (Figure 36) is much less, it is essentially non-existant than that of the wells in the other two groups (Figures 32-35).

XIX. CONCLUSIONS

A. Full proppant volume (40,000 pound) CO_2/sand stimulations were easily executed in the Phillips Sand in the Phillips Co, Montana test area.

B. The maximum sand concentration for CO_2/sand stimulations being pumped at 40 barrels per minute is approximately 5 pounds per gallon. The first well stimulated (1019) accepted 5.9 ppg without any indications of rejection. For design purposes a maximum proppant loading for 40,000 lbs of 20/40 mesh proppant pumped at 40 bpm is 5 ppg.

C. The criteria for success was that the cumulative production from months two through thirteen had to exceed 50 MMcf. This hurdle was based on the production from other nearby wells which were drilled prior to 1998 and also perforated in both the Upper and Lower Phillips Sandstone members.

Only one of the ten wells stimulated in 1998, 1013 met this success criteria, and it was conventionally treated.

D. The twenty-four month cumulative production volumes from the wells stimulated with the liquid-free CO_2/sand process are essentially the same as that from the control wells treated with N_2 Foam and utilizing the same 40,000 pound proppant volume.

E. The well which was stimulated first, 1021 and consequently had the largest CO_2 volume pumped in it, is the poorest producer of the three candidate wells. Some possible explanations are:

1. The geology is poorer,
2. The reservoir pressure is lower,

   The initial shut in well head pressures measured before the wells were turned in line is essentially equal and is not considered to be an explanation of the production variations.

Well	Initial Well Head Press (Psia)
1019	228.6
1020	206.4
1021	214.4

3. The larger CO_2 volume resulted in a reduced proppant pack conductivity.

F. There is a suspicion that the wells which were stimulated with CO_2/sand are being choked by limited conductivity in the hydraulically created fracture, probably as a consequence of the smaller proppant size used (20/40 vs 12/20). This is based on the observation of the nearly identical monthly production volumes from all three candidate wells. And, also on the production comparisons of twenty nearby wells which utilized larger proppant.

It would be anticipated that there should be some variation in the production rates between these wells as there are in the other wells within the field. It is possible that all three of these candidate wells have identical reservoirs but it is a unique and unexpected response.

- All three wells were subsequently checked for well bore obstructions by running coiled tubing in them they and were found to be absent of any debris.

  There was no sand nor liquids present above the perforated interval - there was a small quantity of fresh water below the perforations. It was therefore concluded that if there is a production limiting mechanism that it must be upstream of the perforations.

- Tubing was installed in all three candidate wells and the gas production rates did not change nor was there any liquid production observed. The conclusion is that there is no production impediment caused by liquids or other mechanical obstructions within the well bore, and if there is a limiting mechanism that it must lie within the fracture or reservoir.

G. The size of the proppant differed between the two stimulation types. The N_2 Foam stimulations utilized 12/20 sand and the CO_2/sand stimulations incorporated smaller 20/40 sand proppant. The intention was to utilize the smaller proppant on the first CO_2/sand stimulation and if no resistance to sand placement was encountered to then utilize the larger 12/20 proppant size. Upon successful placement of the 20/40 in the first CO_2/sand stimulation unsuccessful attempts were made to procure 12/20 proppant. The larger proppant was locally present but made unavailable by a competing service company.

H. The wells within the test area which were stimulated prior to 1998 have greater monthly production rates. There are some possible explanations:

- The geology is poorer. This is considered the least likely explanation because of the number of wells drilled and the resulting knowledge of the reservoir character.

- The reservoir pressure has diminished.

- The practice of stimulating only the Upper Phillips Sand member is not accessing all of the available gas reserves.

I. The monthly production rates from both the control wells (N_2 Foam) and the candidate wells (CO_2/sand) readily cleaned up following the stimulation, and specifically that the wells stimulated with N_2 Foam did not exhibit a reduced production rate or slow clean up period.

J. Both groups of wells, control and candidate generally experienced a five month period of higher "flush production" rate.

XX. RECOMMENDATIONS

A. Identify and execute other CO_2/sand candidate well opportunities in the Phillips Sandstone near the test area and to utilize 12/20 proppant.

Conversations with Canadian Fracmaster personnel indicate that similar formations within 150 miles of the test area have been sometimes successfully - but not always - stimulated with CO_2/sand treatments which utilized 12/20 proppant.

B. Attempt to determine an explanation as to why the cumulative production volumes from the wells stimulated in 1998 are less than those completed earlier.

C. Identify the lowest landed cost for reliably delivered CO_2.

This report has been prepared as a summary of the CO_2/sand stimulation demonstrations in the Phillips Sandstone in Phillips County, Montana in July 1998. It is considered to be complete and to fairly represent and assess the activities, results, and conclusions of these efforts.

DEFAULT	AITH .004	F[illegible]	FIELD	13-JUN-1998 20:26	1356.0 FT	137.5 FT

Output DLIS Files

DEFAULT	AITH .006	FN:5	FIELD	13-JUN-1998 21:36	1356.0 FT	138.0 FT

OP System Version: 7C0-712

DBM

Well #1015
p. 1 of 2

PIP SUMMARY

Time Mark Every 60 S

Producibility
From DPHI to SPHI

WELL # 1015

Gas
From DT to TNPH

SP (SP)
-80 (MV) 20

Tool/Tot. Drag From D3T to STIA

Env.Corr.Thermal Neutron Porosity (TNPH)
0.6 (V/V) 0

Gamma Ray (GR)
(GAPI) 200

Cable Drag From STIA to STIT

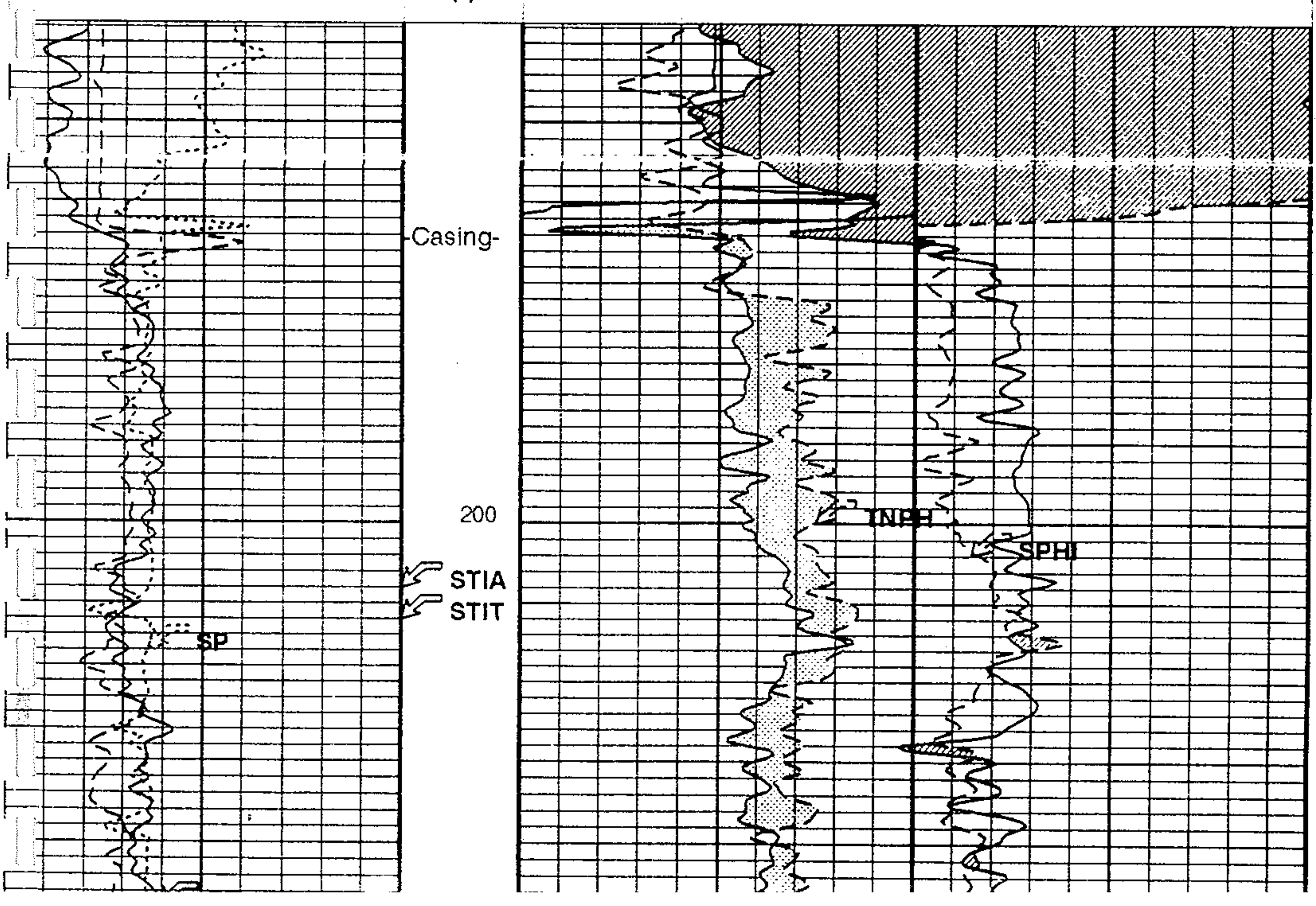
Delta-T (DT)
200 (US/F) 100

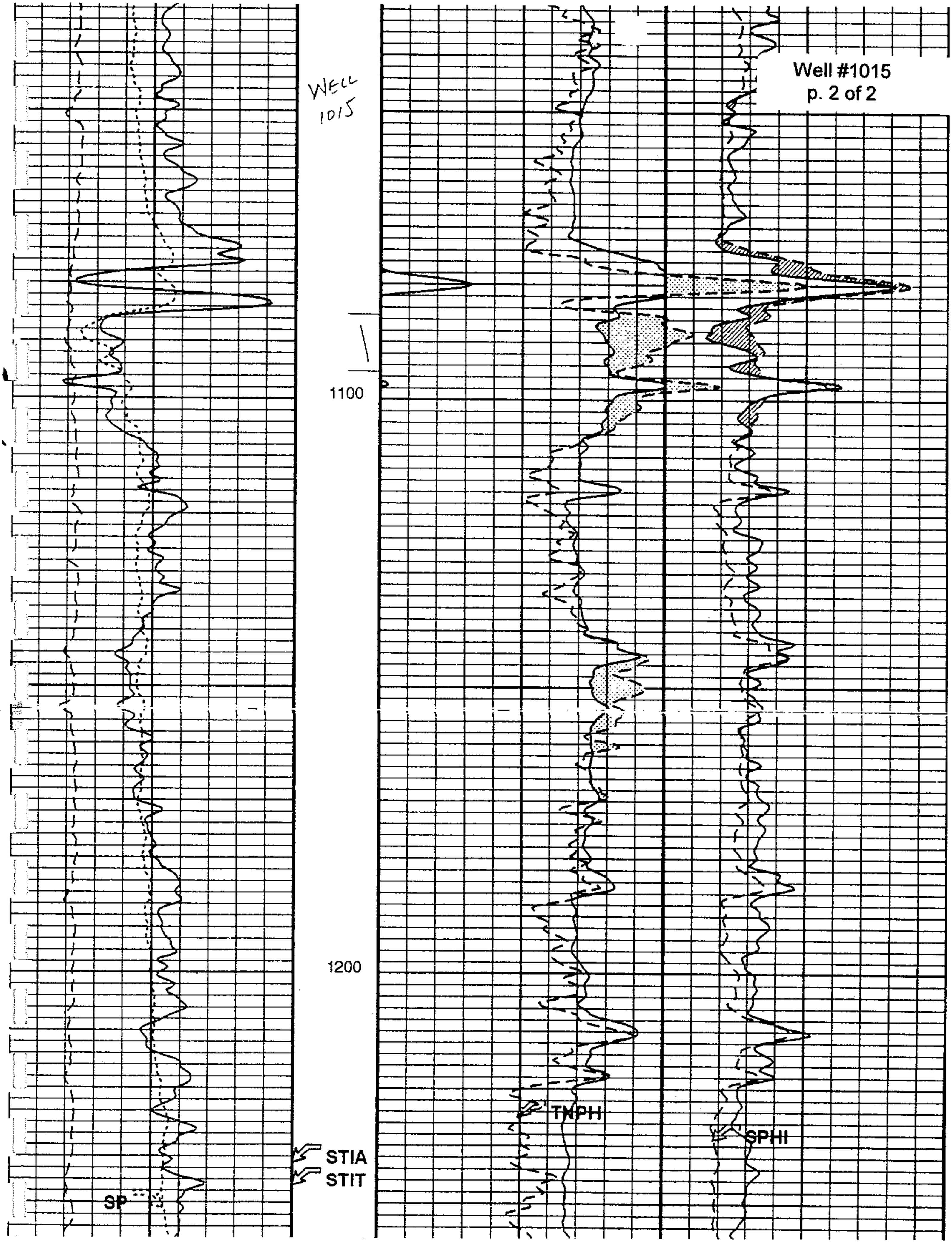
Sonic Porosity (SPHI)
0.6 (V/V) 0

Caliper (CALI)
(IN) 14

Stuck Stretch (STIT)
0 (F) 50

Density Porosity (DPHI)
0.6 (V/V) 0




Well #1015
p. 2 of 2
WELL
1015
1100
1200
TNPH
SPHI
STIA
STIT
SP

Output DLIS Files

DEFAULT AITH .004 FN:3 FIELD 13-JUN-1998 20:26 1356.0 FT 138.0 FT

Integrated Hole/Cement Volume Summary

Hole Volume = 263.38 F3

Cement Volume = 132.34 F3 (assuming 4.50 IN casing O.D.)

Computed from 1350.0 FT to 164.0 FT using data channel(s) CALI

Well #1015
p. 1 of 2

OP System Version: 7C0-712

DBM

PIP SUMMARY

⊢ Integrated Hole Volume Minor Pip Every 10 F3
⊢ Integrated Hole Volume Major Pip Every 100 F3
⊣ Integrated Cement Volume Minor Pip Every 10 F3
⊣ Integrated Cement Volume Major Pip Every 100 F3

Time Mark Every 60 S

Tension (TENS) 10000 (LBF)

AIT-H 90 Inch Investigation (AHT90) 0.2 (OHMM) 200

AIT-H 60 Inch Investigation (AHT60) 0.2 (OHMM) 200

Tool/Tot. Drag From D3T to STIA

AIT-H 30 Inch Investigation (AHT30) 0.2 (OHMM) 200

Well 1015

Gamma Ray (GR) 50 (GAPI) 200

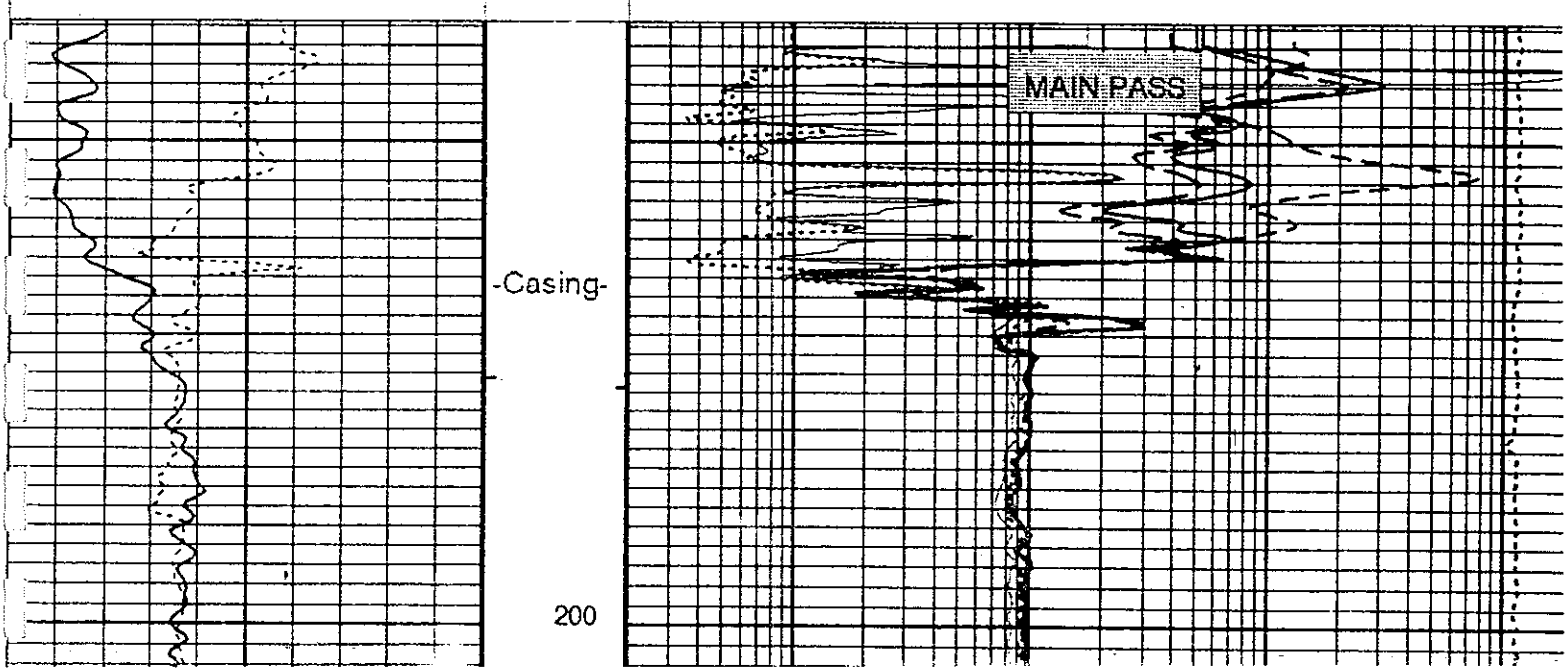
Cable Drag From STIA to STIT

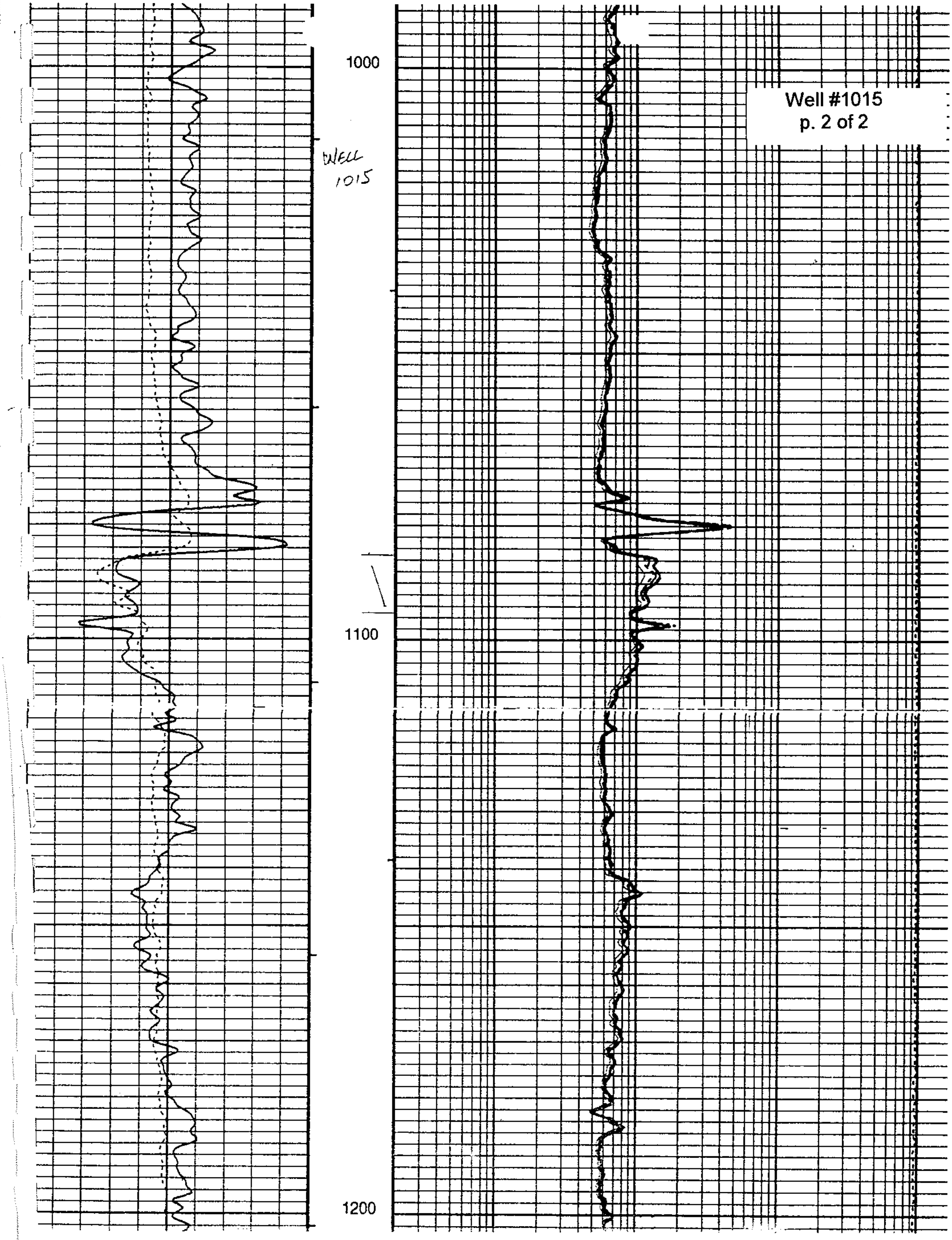
AIT-H 20 Inch Investigation (AHT20) 0.2 (OHMM) 200

SP (SP) 30 (MV) 20

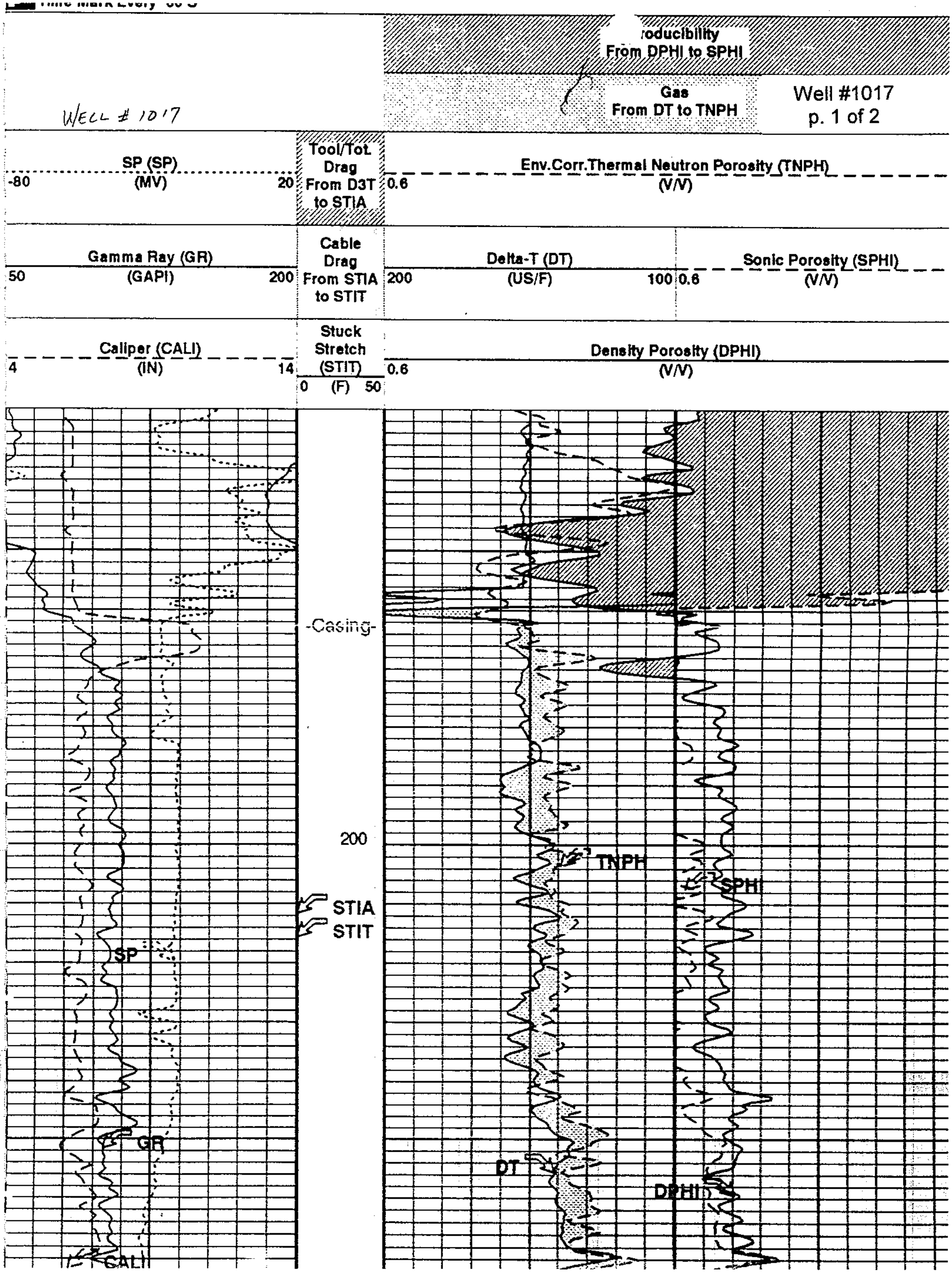
Stuck Stretch (STIT) 0 (F) 50

AIT-H 10 Inch Investigation (AHT10) 0.2 (OHMM) 200



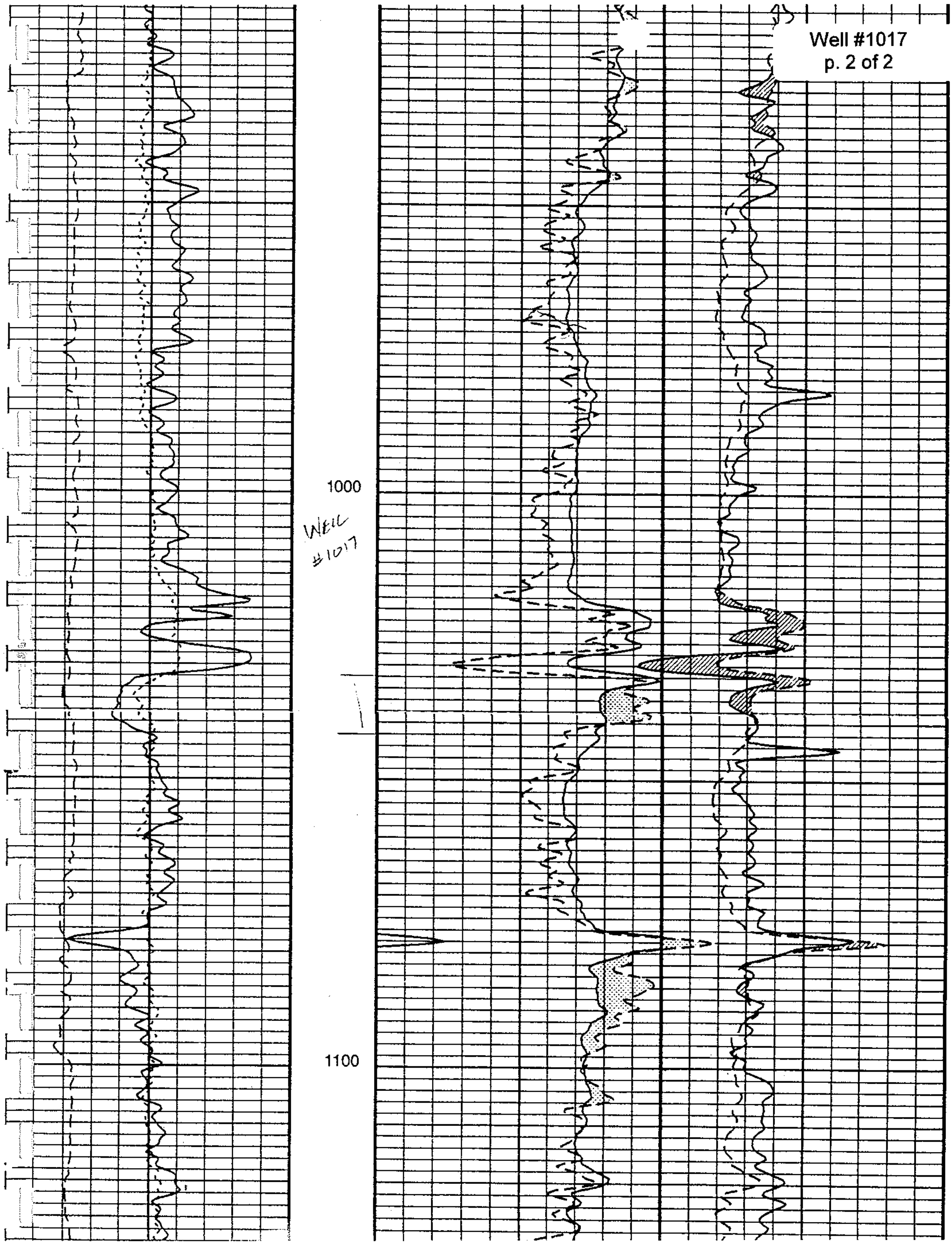


Well #1015
p. 2 of 2
WELL
1015
1000
1100
1200



roducibility
From DPHI to SPHI
Gas
From DT to TNPH
WELL # 1017
Well #1017
p. 1 of 2
SP (SP)
-80 (MV) 20
Tool/Tot. Drag From D3T to STIA
Env.Corr.Thermal Neutron Porosity (TNPH)
0.6 (V/V)
Gamma Ray (GR)
50 (GAPI) 200
Cable Drag From STIA to STIT
Delta-T (DT)
200 (US/F) 100
Sonic Porosity (SPHI)
0.6 (V/V)
Caliper (CALI)
4 (IN) 14
Stuck Stretch (STIT)
0 (F) 50
Density Porosity (DPHI)
0.6 (V/V)
-Casing-
200
TNPH
SPHI
STIA
STIT
SP
GR
DT
DPHI
CALI

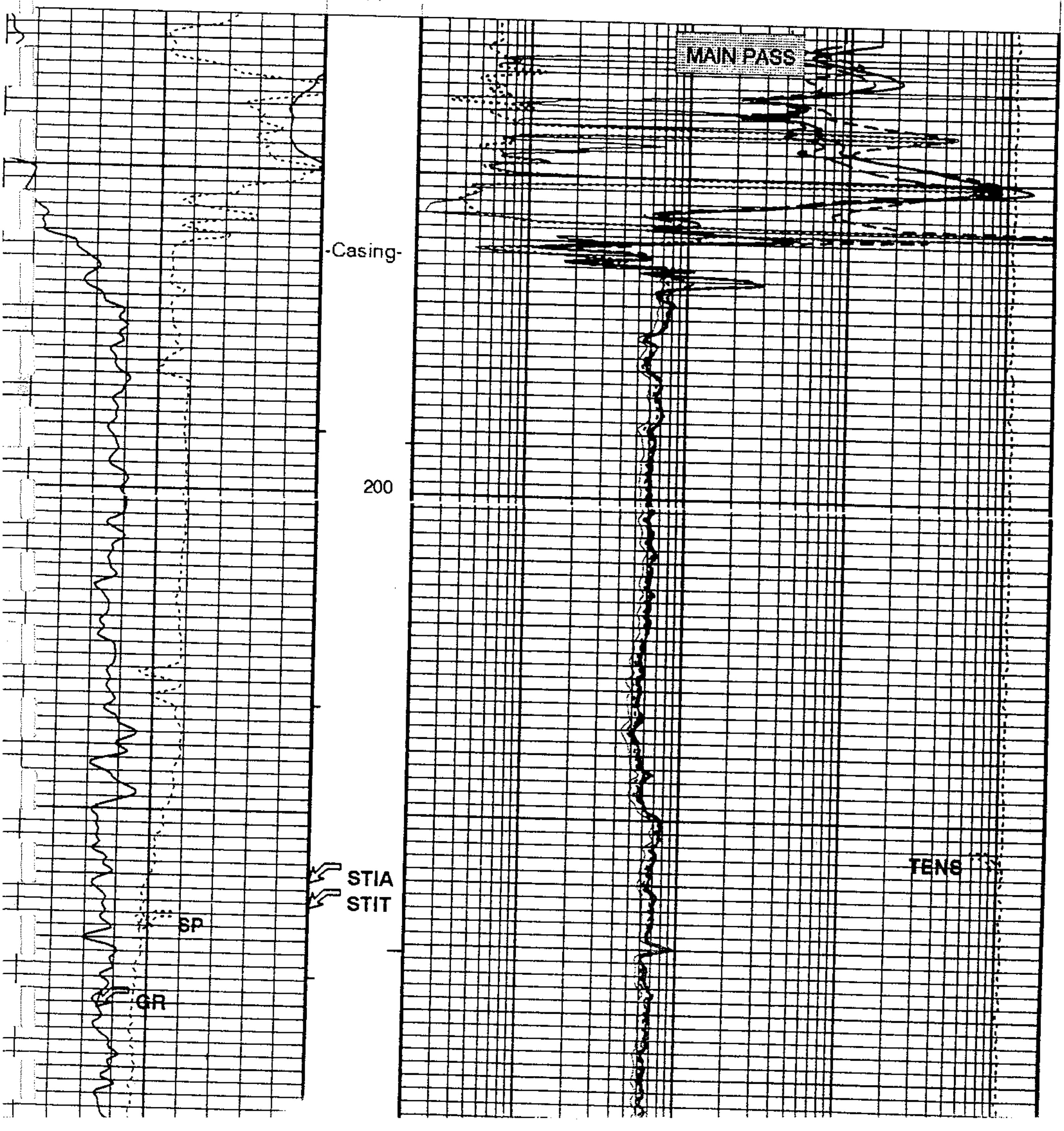
Well #1017
p. 2 of 2



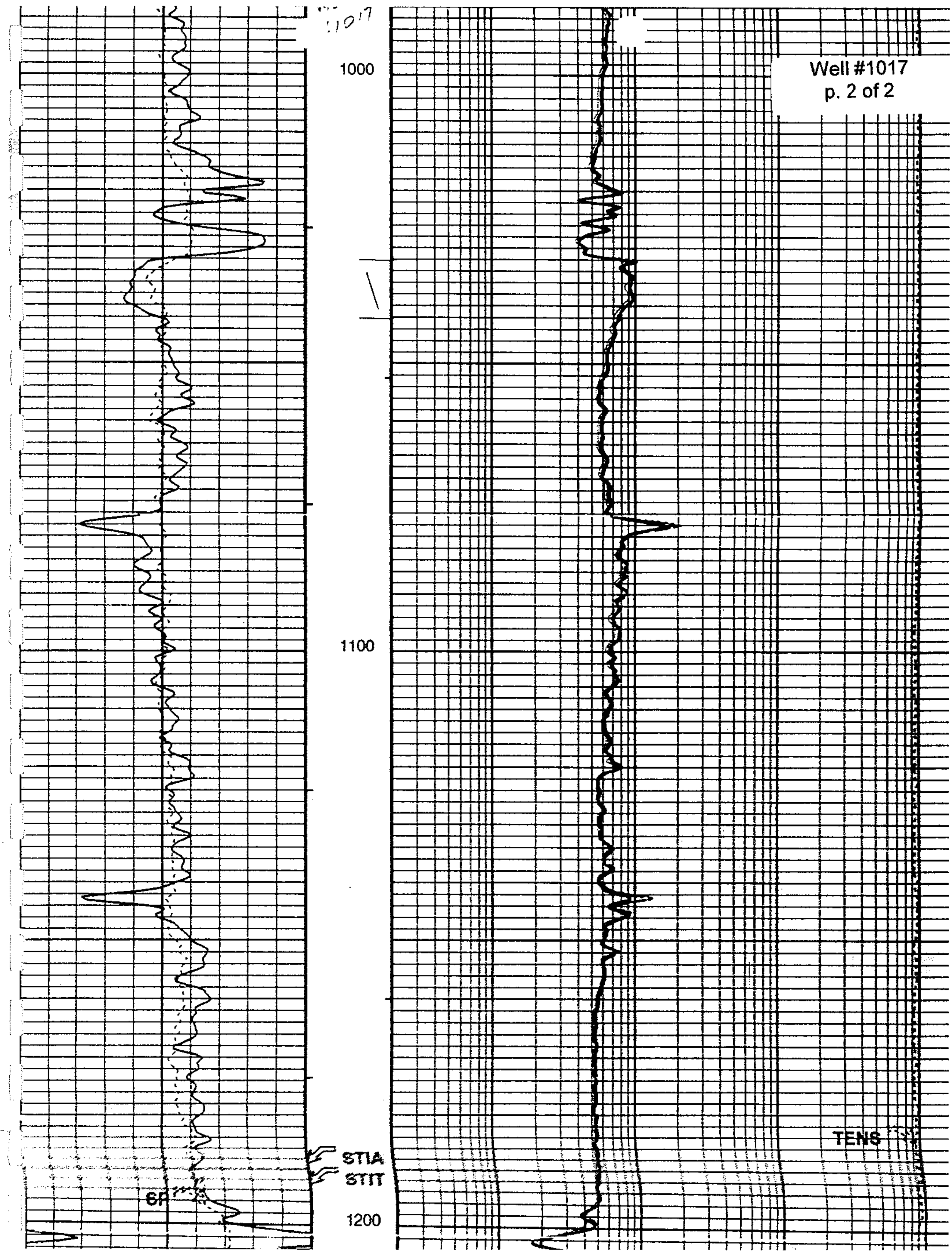
Well # 1017

Well #1017
p. 1 of 2

Gamma Ray (GR) (GAPI) 200	Drag n D3T to STIA	AIT-H 30 In vestigation (AHT30) (OHMM) 0.2 – 2000
	Cable Drag From STIA to STIT	AIT-H 20 Inch Investigation (AHT20) (OHMM) 0.2 – 2000
SP (SP) (MV) -80 – 20	Stuck Stretch (STIT) 0 (F) 50	AIT-H 10 Inch Investigation (AHT10) (OHMM) 0.2 – 2000



Well #1017
p. 2 of 2



Input DLIS Files

DEFAULT	AITH .005	FN:4	FIELD	11-JUN-1998 02:34	1284.0 FT	124.5 FT

Output DLIS Files

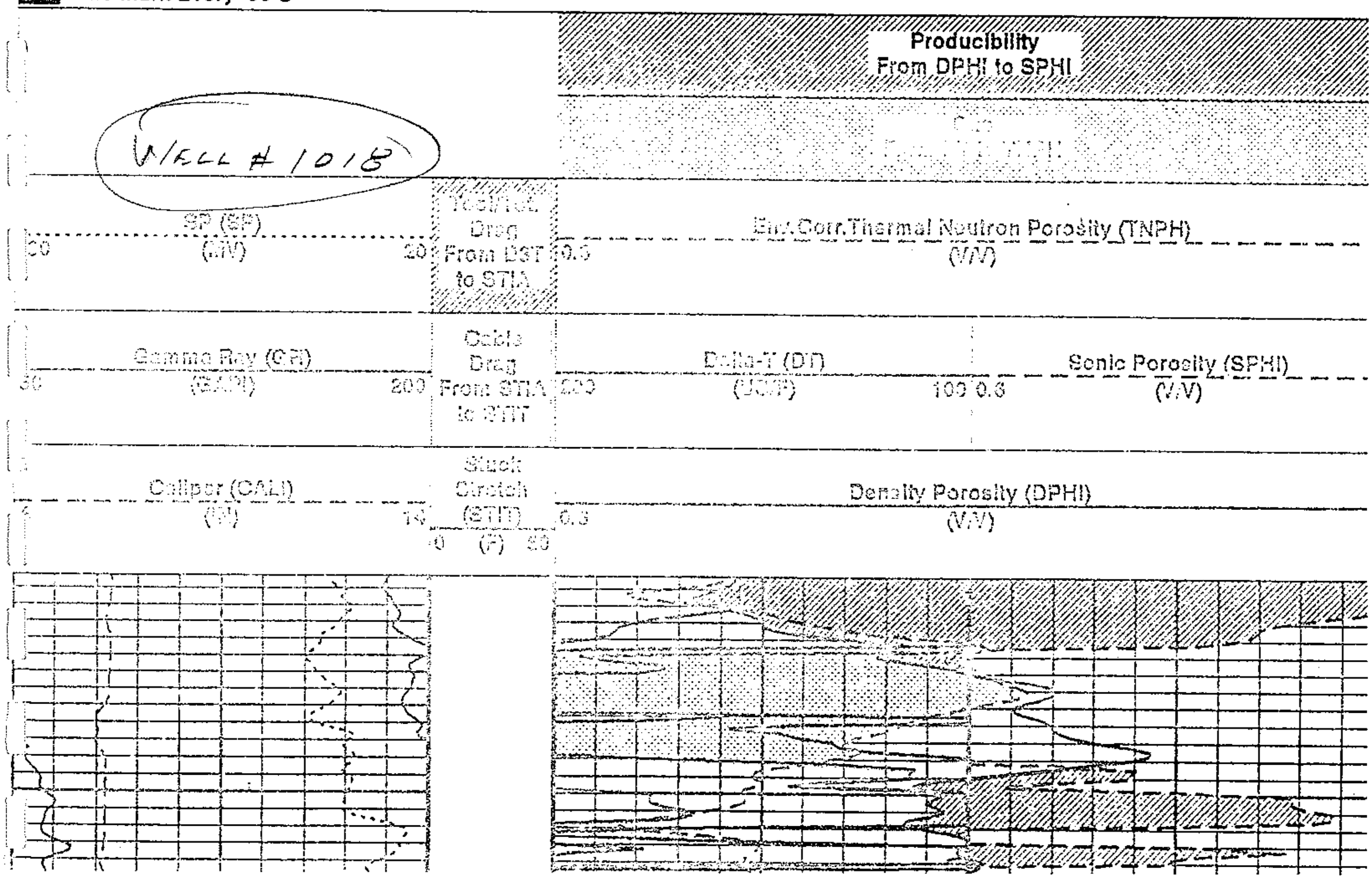
DEFAULT	AITH .006	FN:5	FIELD	11-JUN-1998 03:20	1284.0 FT	125.0 FT

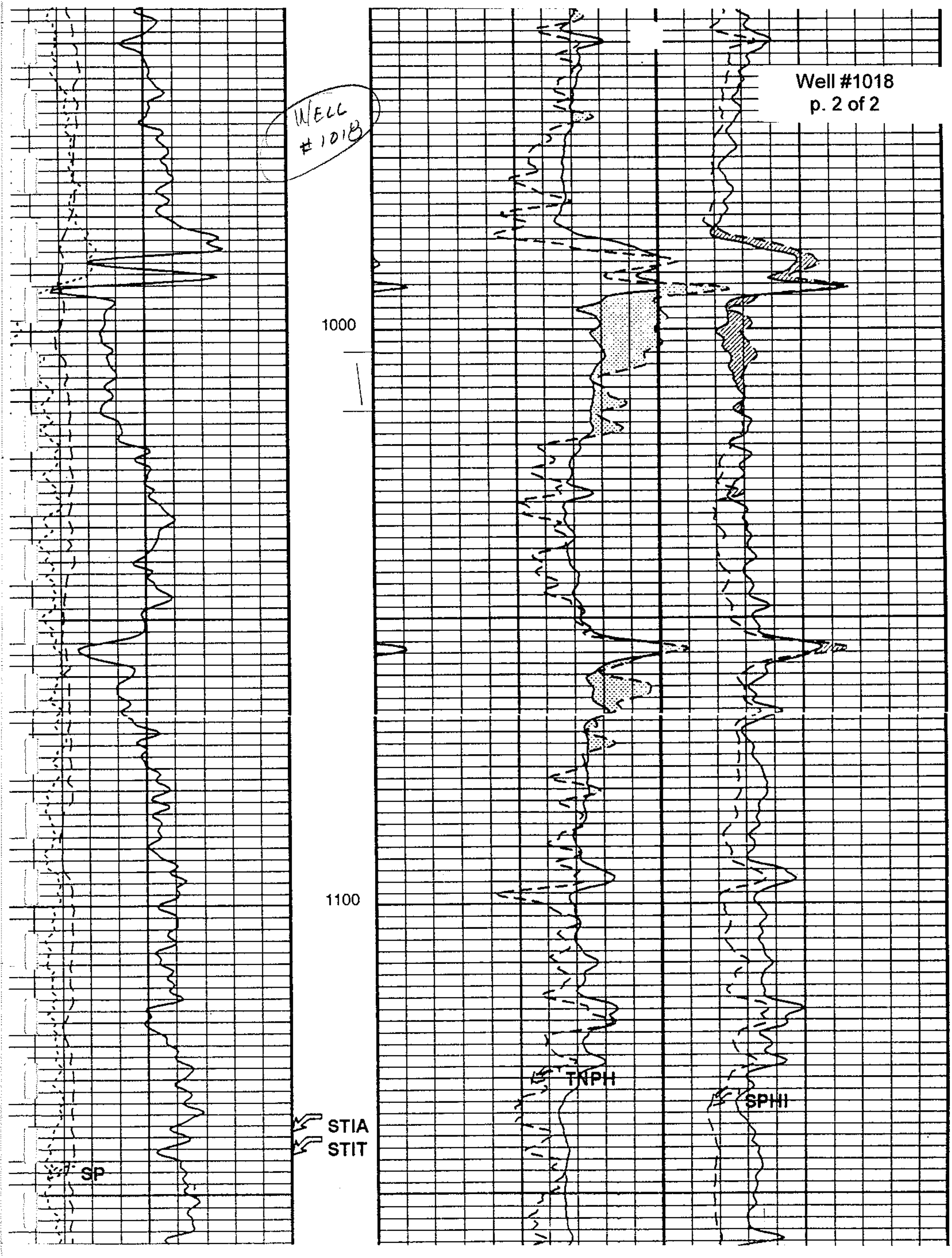
OP System Version: 7C0-712

DBM

PIP SUMMARY

Time Mark Every 60 S




Well #1018
p. 2 of 2
WELL #1018
1000
1100
SP
STIA
STIT
TNPH
SPHI

Output DLIS Files

DEFAULT AITH .005 :4 FIELD 11-JUN-1998 02:34

Output DLIS Files

DEFAULT AITH .005 FN:4 FIELD 11-JUN-1998 02:34 1284.0 FT 124.5 FT

Integrated Hole/Cement Volume Summary

Hole Volume = 245.34 F3
Cement Volume = 122.48 F3 (assuming 4.50 IN casing O.D.)
Computed from 1275.0 FT to 163.0 FT using data channel(s) CALI

OP System Version: 7C0-712

DBM

PIP SUMMARY

⊢ Integrated Hole Volume Minor Pip Every 10 F3
⊢ Integrated Hole Volume Major Pip Every 100 F3
⊣ Integrated Cement Volume Minor Pip Every 10 F3
⊣ Integrated Cement Volume Major Pip Every 100 F3

Time Mark Every 60 S

Tension (TENS)
10000 (LBF)

AIT-H 90 Inch Investigation (AHT90)
0.2 (OHMM) 200

AIT-H 60 Inch Investigation (AHT60)
0.2 (OHMM) 200

Tool/Tot. Drag From D3T to STIA

AIT-H 30 Inch Investigation (AHT30)
0.2 (OHMM) 200

WELL # 1018

Gamma Ray (GR)
50 (GAPI) 200

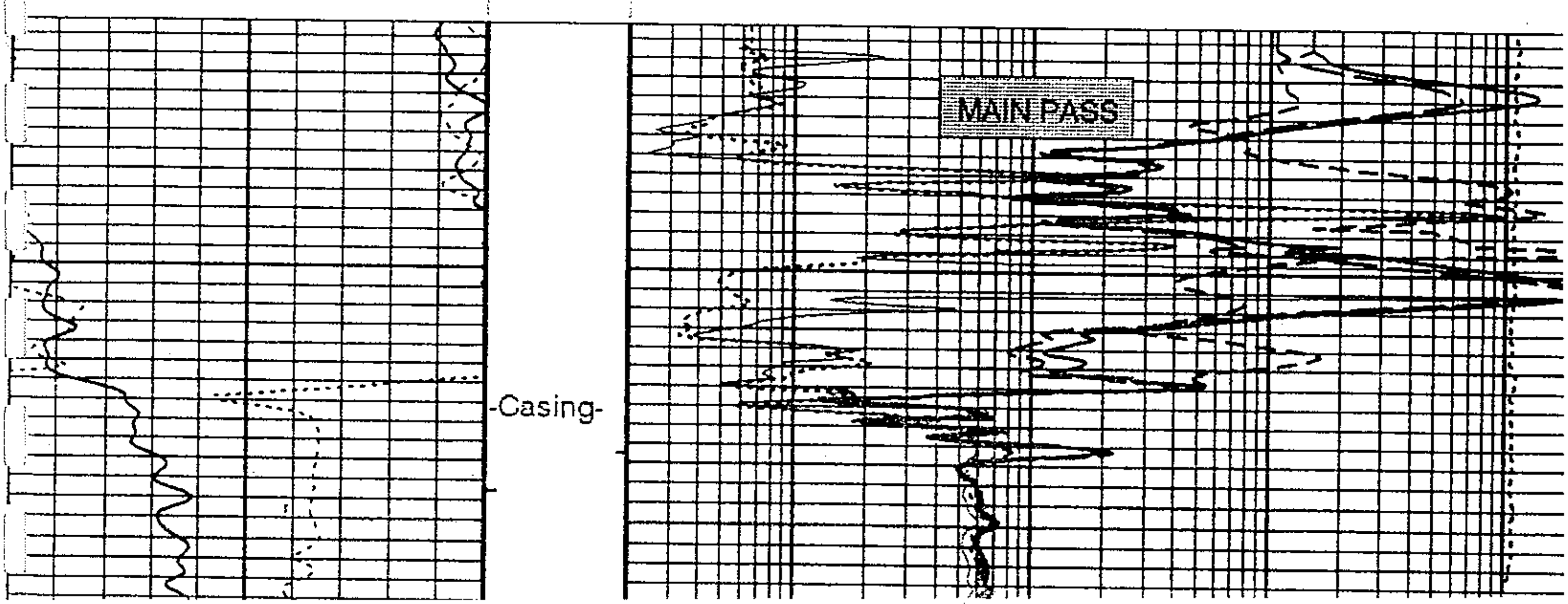
Cable Drag From STIA to STIT

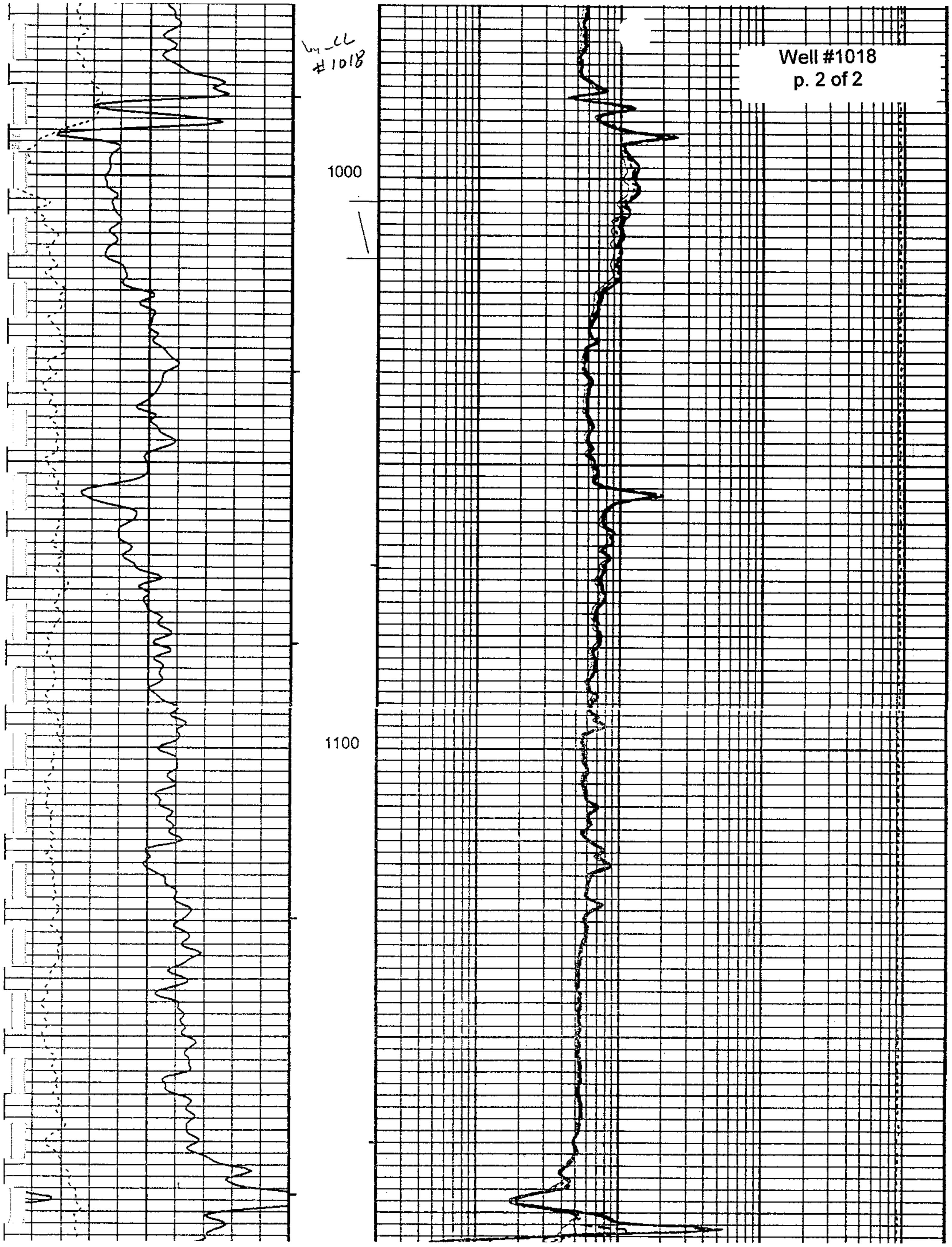
AIT-H 20 Inch Investigation (AHT20)
0.2 (OHMM) 200

SP (SP)
-80 (MV) 20

Stuck Stretch (STIT)
0 (F) 50

AIT-H 10 Inch Investigation (AHT10)
0.2 (OHMM) 200




Well
#1018
1000
1100
Well #1018
p. 2 of 2

Input DLIS Files

DEFAULT	AITH .007	FN:4	FIELD	9-JUN-1998 04:02	1254.0 FT	107.0 FT

Output DLIS Files

DEFAULT	AITH .010	FN:7	FIELD	9-JUN-1998 05:20	1254.0 FT	107.2 FT

OP System Version: 7C0-712

DBM

Well #1019
p. 1 of 2

PIP SUMMARY

Time Mark Every 60 S

Producibility
From DPHI to SPHI

Gas
From DT to TNPH

Well #1019

SP (SP)
-80 (MV) 20

Tool/Tot. Drag From D3T to STIA

Env.Corr.Thermal Neutron Porosity (TNPH)
0.6 (V/V)

Gamma Ray (GR)
50 (GAPI) 200

Cable Drag From STIA to STIT

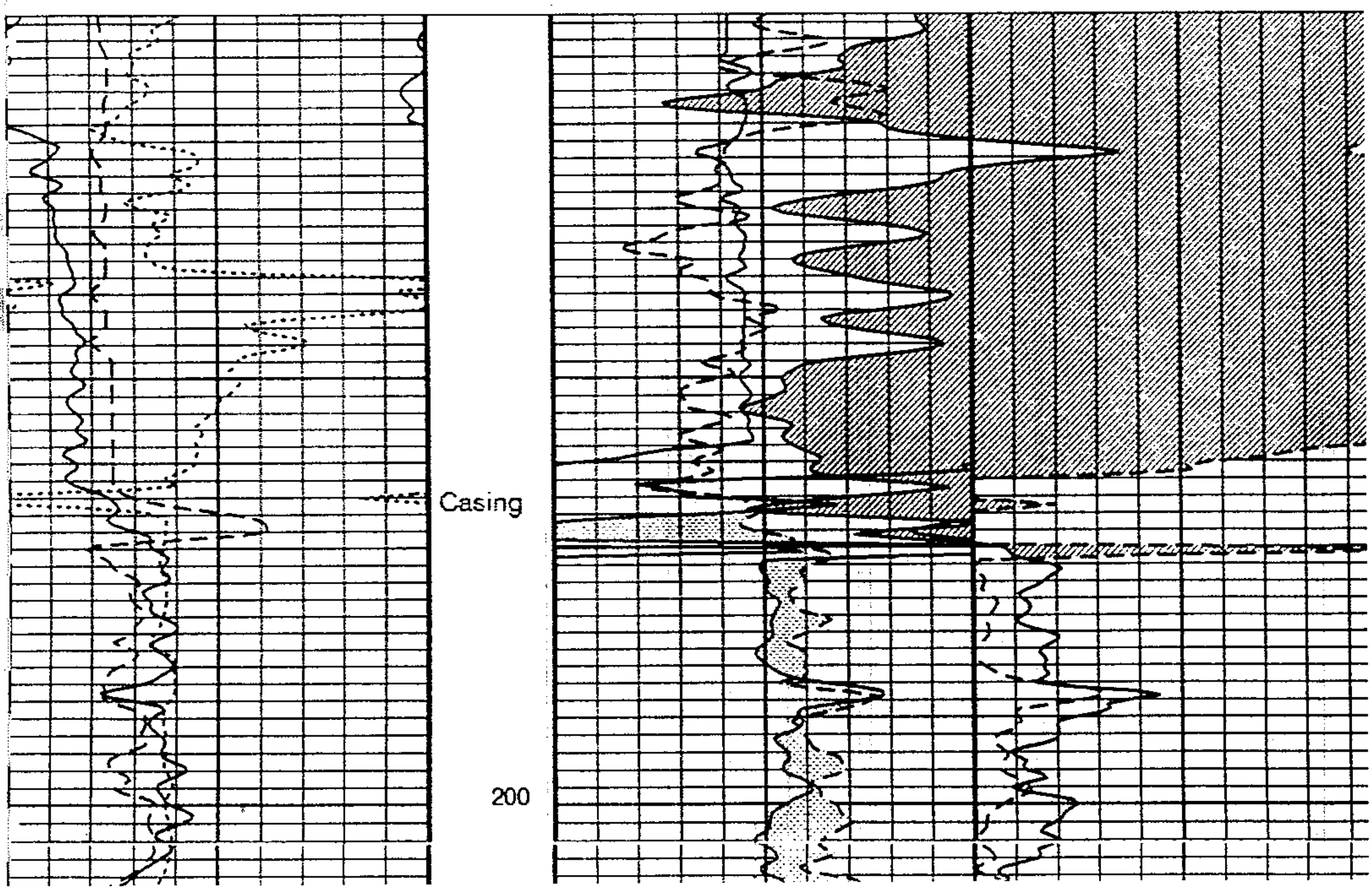
Delta-T (DT)
200 (US/F) 100

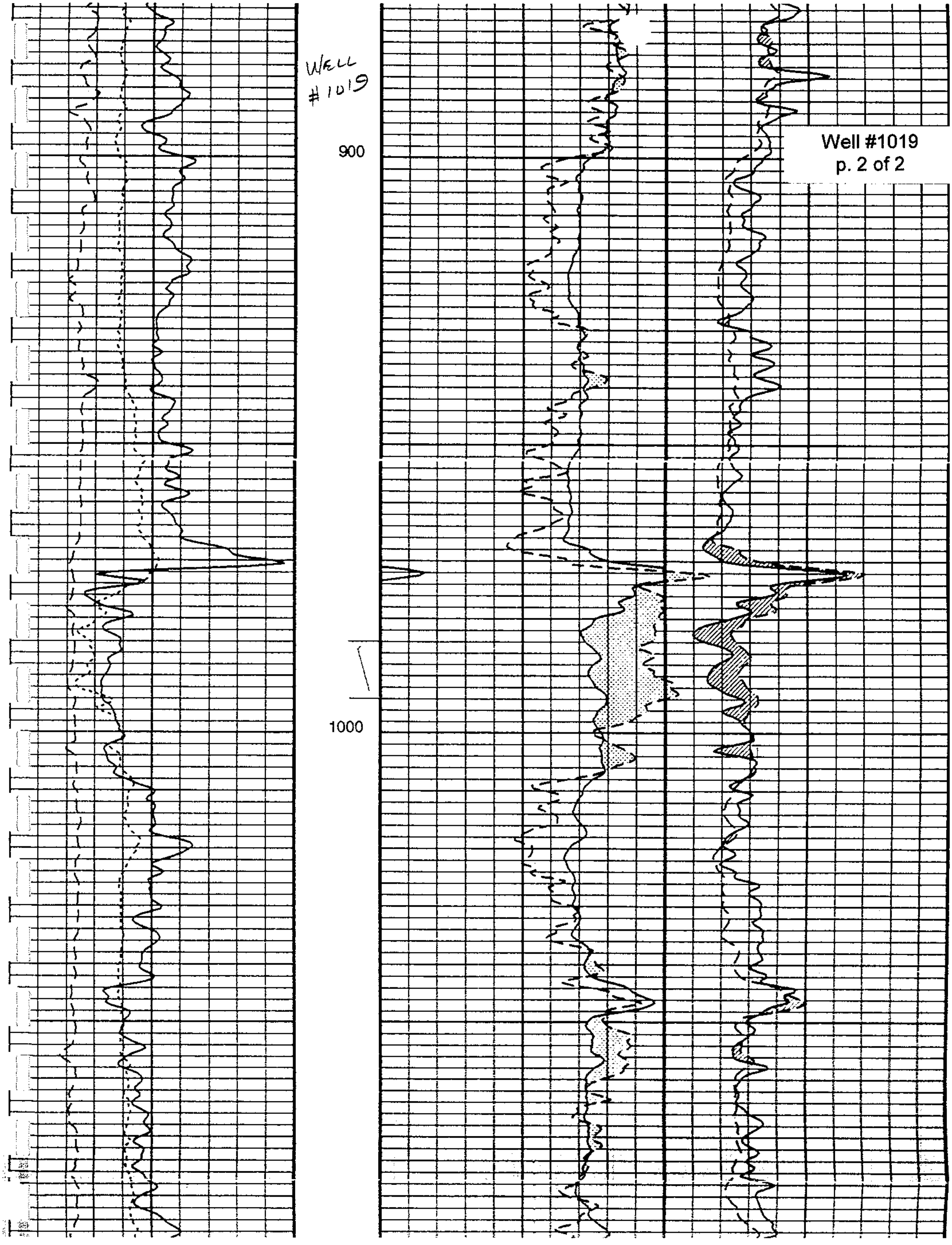
Sonic Porosity (SPHI)
0.6 (V/V)

Caliper (CALI)
4 (IN) 14

Stuck Stretch (STIT)
0 (F) 50

Density Porosity (DPHI)
0.6 (V/V)




WELL
#1019
900
1000
Well #1019
p. 2 of 2

WELL # 1019

Well #1019
p. 1 of 2

AIT-H 90 Inch Investigation (AHT90)
0.2 (OHMM) 2000

AIT-H 60 Inch Investigation (AHT60)
0.2 (OHMM) 2000

Tool/Tot. Drag From D3T to STIA

AIT-H 30 Inch Investigation (AHT30)
0.2 (OHMM) 2000

Gamma Ray (GR)
50 (GAPI) 200

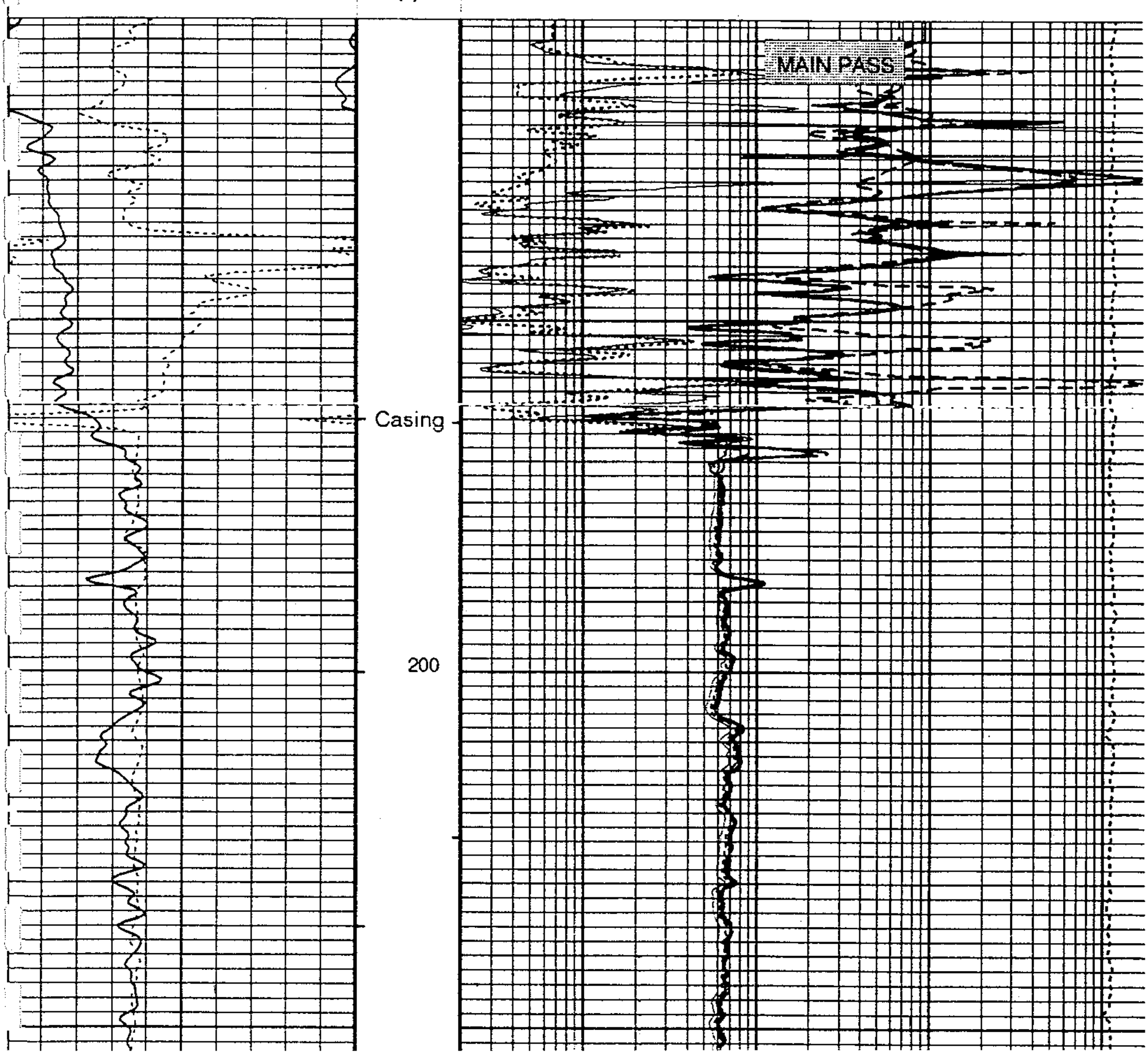
Cable Drag From STIA to STIT

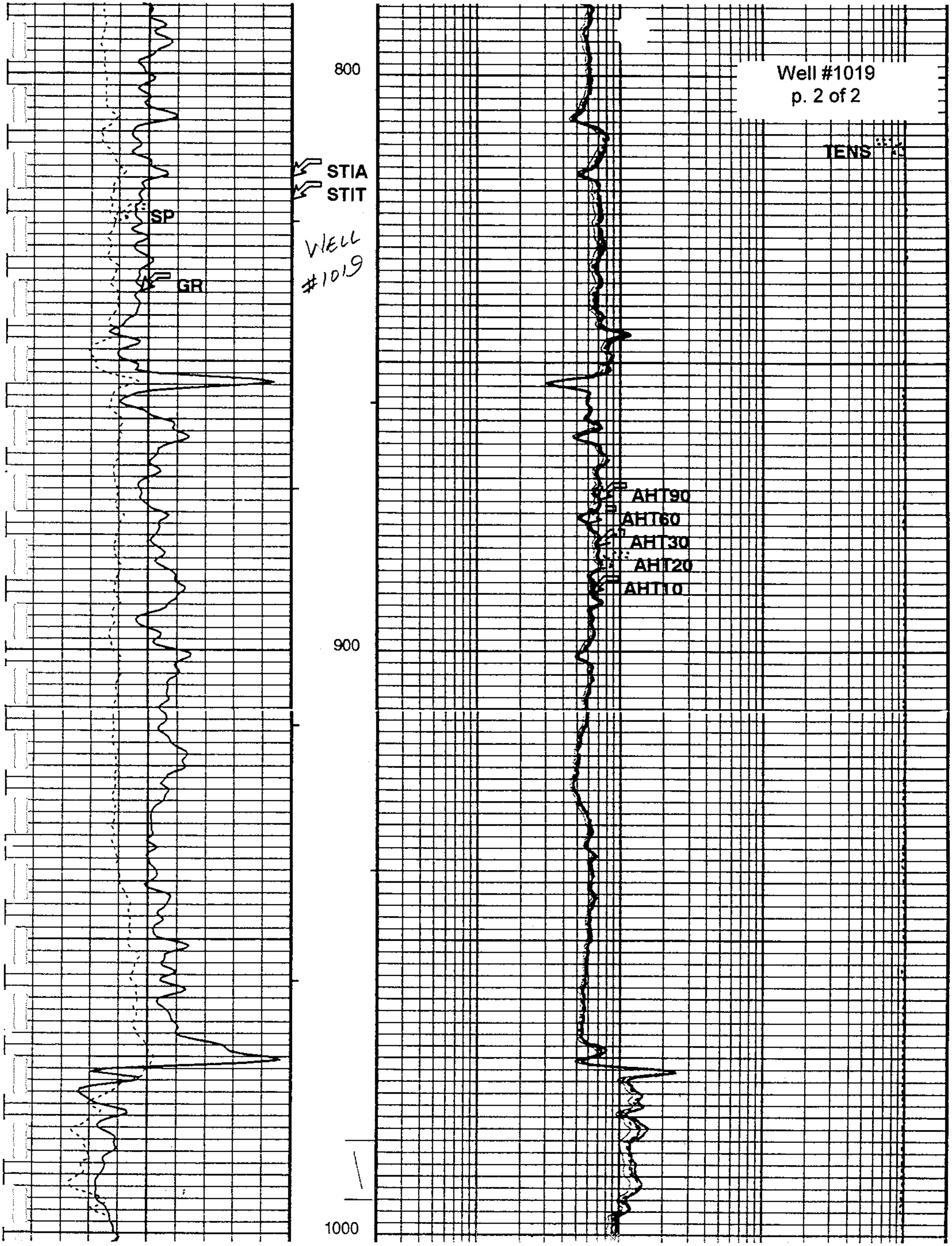
AIT-H 20 Inch Investigation (AHT20)
0.2 (OHMM) 2000

SP (SP)
80 (MV) 20

Stuck Stretch (STIT)
0 (F) 50

AIT-H 10 Inch Investigation (AHT10)
0.2 (OHMM) 2000




Well #1019
p. 2 of 2
TENS
800
STIA
STIT
SP
GR
WELL #1019
AHT90
AHT60
AHT30
AHT20
AHT10
900
1000

DEFAULT AITH .008 7 FIELD 7-JUN-1998 20:29 1230.0 FT 76.5 FT

Integrated Hole/Cement Volume Summary

Well #1020
p. 1 of 2

Hole Volume = 261.83 F3
Cement Volume = 134.93 F3 (assuming 4.50 IN casing O.D.)
Computed from 1225.0 FT to 76.5 FT using data channel(s) CALI

OP System Version: 7C0-712

DBM

PIP SUMMARY

⊢ Integrated Hole Volume Minor Pip Every 10 F3
⊢ Integrated Hole Volume Major Pip Every 100 F3
⊣ Integrated Cement Volume Minor Pip Every 10 F3
⊣ Integrated Cement Volume Major Pip Every 100 F3

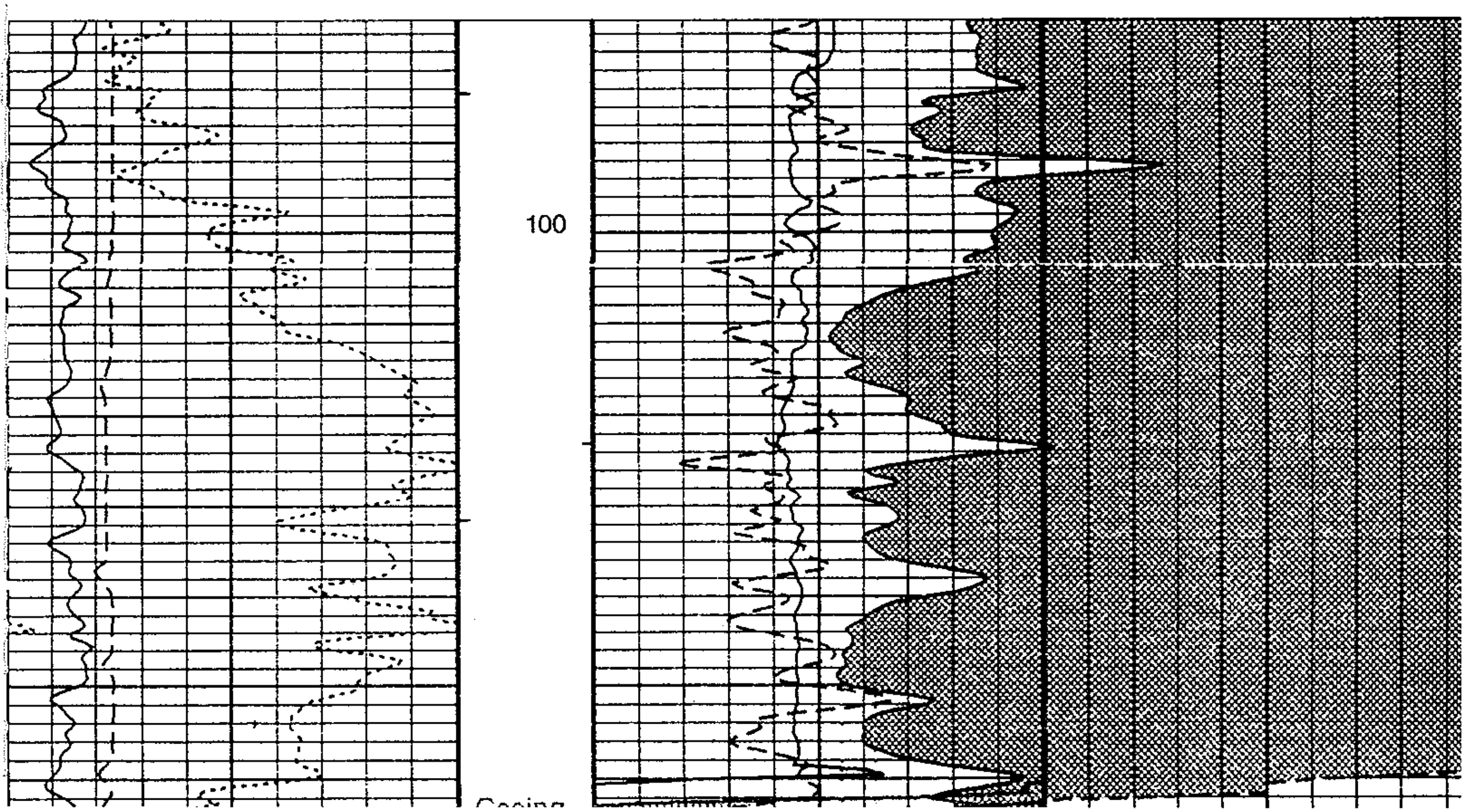
Time Mark Every 60 S

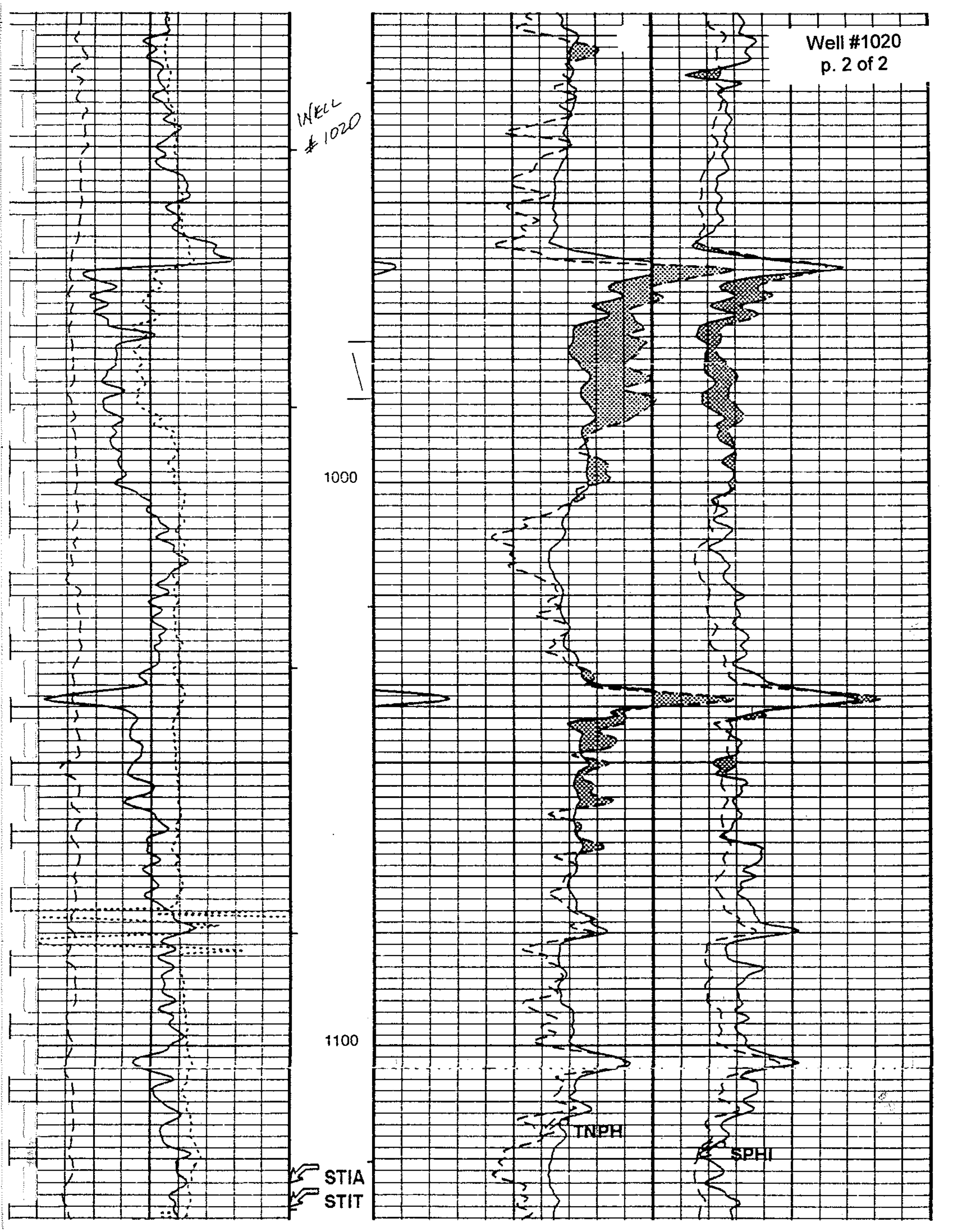
Producibility
From DPHI to SPHI

Gas
From DT to TNPH

WELL #1020

SP (SP) -80 (MV) 20	Tool/Tot. Drag From D3T to STIA	Env.Corr.Thermal Neutron Porosity (TNPH) 0.6 (V/V)
Gamma Ray (GR) 50 (GAPI) 200	Cable Drag From STIA to STIT	Delta-T (DT) 200 (US/F) 100 / Sonic Porosity (SPHI) 0.6 (V/V)
Caliper (CALI) 4 (IN) 14	Stuck Stretch (STIT) 0 (F) 50	Density Porosity (DPHI) 0.6 (V/V)




WELL
#1020
1000
1100
STIA
STIT
TNPH
SPHI

In[illegible]grated Hole/Cement Volume [illegible]ummary

Hole Volume = 261.83 F3

Cement Volume = 134.93 F3 (assuming 4.50 IN casing O.D.)

Computed from 1225.0 FT to 76.5 FT using data channel(s) CALI

Well #1020
p. 1 of 2

OP System Version: 7C0-712

DBM

PIP SUMMARY

Integrated Hole Volume Minor Pip Every 10 F3
Integrated Hole Volume Major Pip Every 100 F3
Integrated Cement Volume Minor Pip Every 10 F3
Integrated Cement Volume Major Pip Every 100 F3

Time Mark Every 60 S

Tension (TENS) 10000 (LBF)

AIT-H 90 Inch Investigation (AHT90) 0.2 (OHMM)

AIT-H 60 Inch Investigation (AHT60) 0.2 (OHMM)

Tool/Tot. Drag From D3T to STIA

AIT-H 30 Inch Investigation (AHT30) 0.2 (OHMM)

WELL # 1020

Gamma Ray (GR) 50 (GAPI) 200

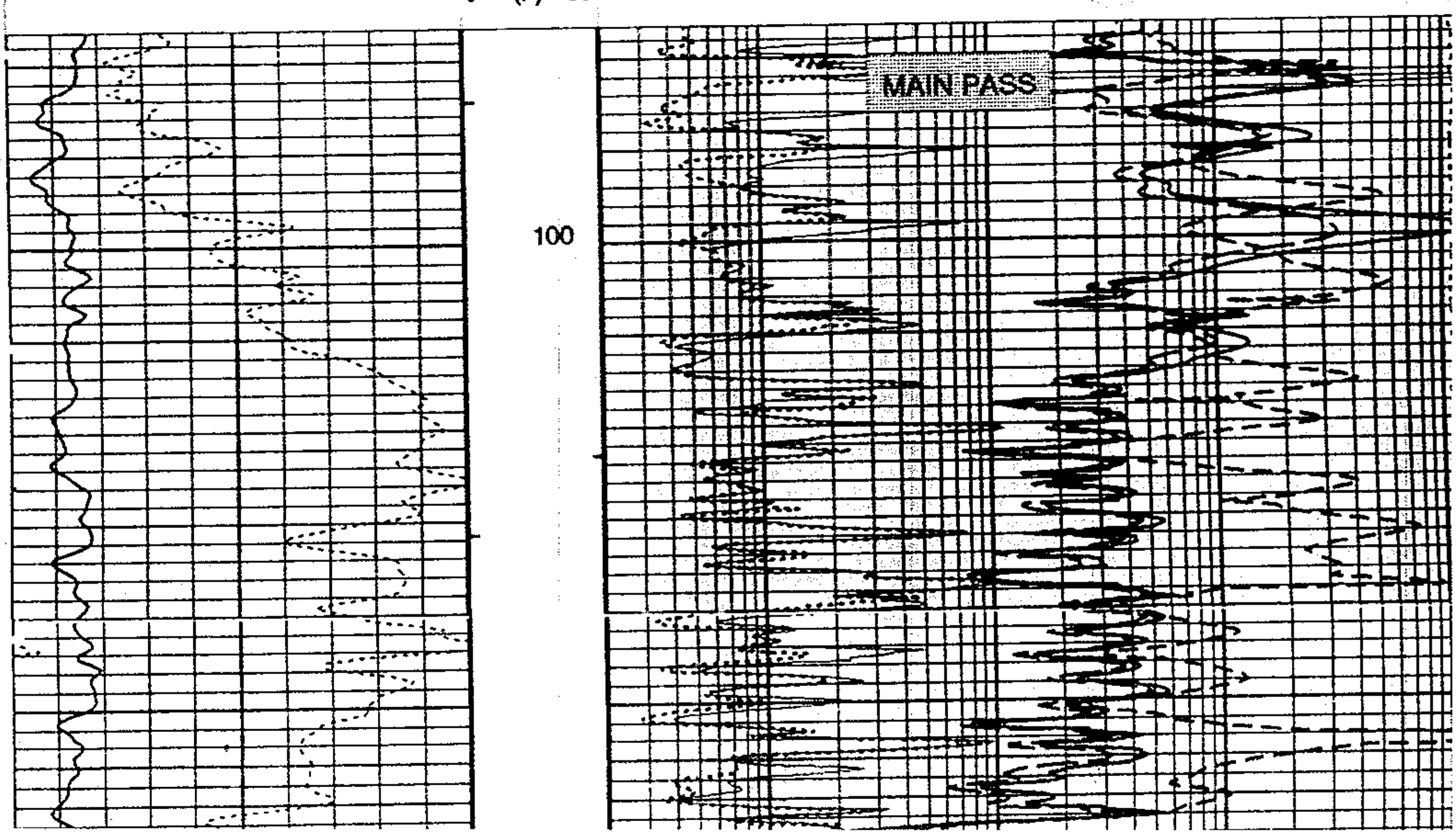
Cable Drag From STIA to STIT

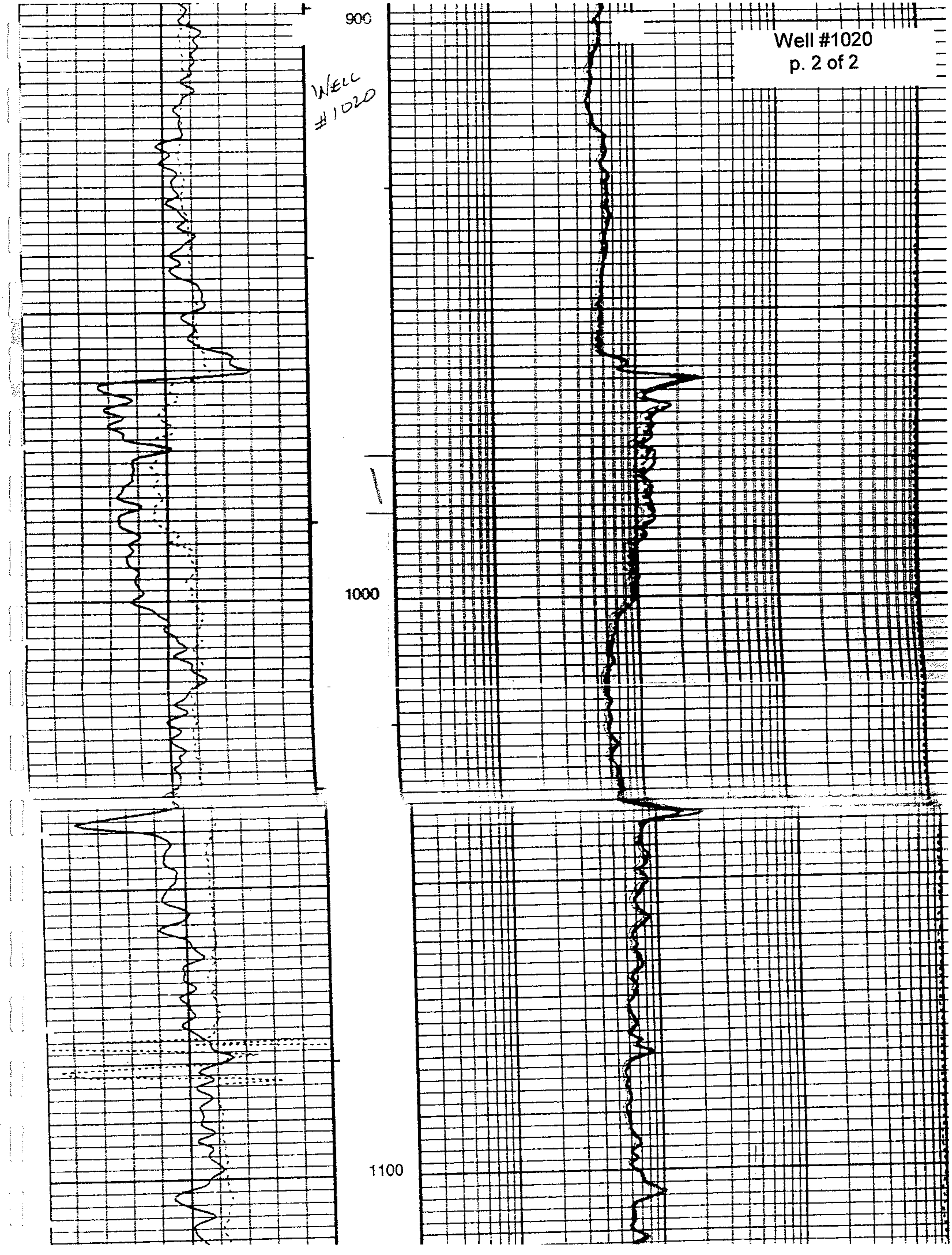
AIT-H 20 Inch Investigation (AHT20) 0.2 (OHMM)

SP (SP) -80 (MV) 20

Stuck Stretch (STIT) 0 (F) 50

AIT-H 10 Inch Investigation (AHT10) 0.2 (OHMM)




WELL
#1020
900
1000
1100

P System Version: 8C1-205

MCM

AIT-H	APCW-98Q1	LDT-D	APCW-98Q1
-H	APCW-98Q1	SDT-C	rpcwx-1046
-L	APCW-98Q1	TCC-B	APCW-98Q1

Well #1021
p. 1 of 2

PIP SUMMARY

'ime Mark Every 60 S

Producibility
From DPHI to SPHI

Gas
From DT to TNPH

WELL #1021

SP (SP)
80 (MV) 20

Env.Corr.Thermal Neutron Porosity (TNPH)
0.6 (V/V) 0

Gamma Ray (GR)
(GAPI) 200

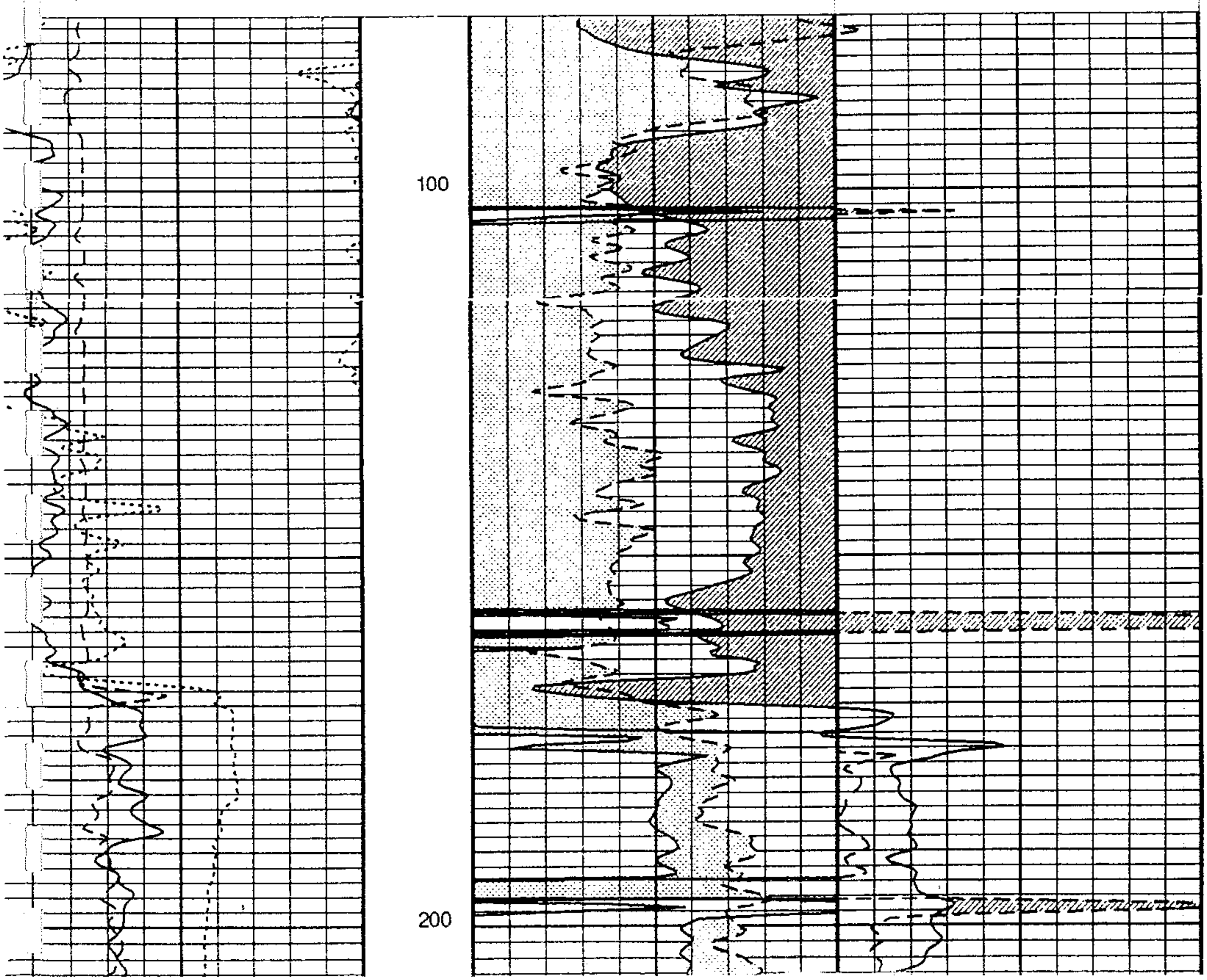
Density Porosity (DPHI)
0.6 (V/V) 0

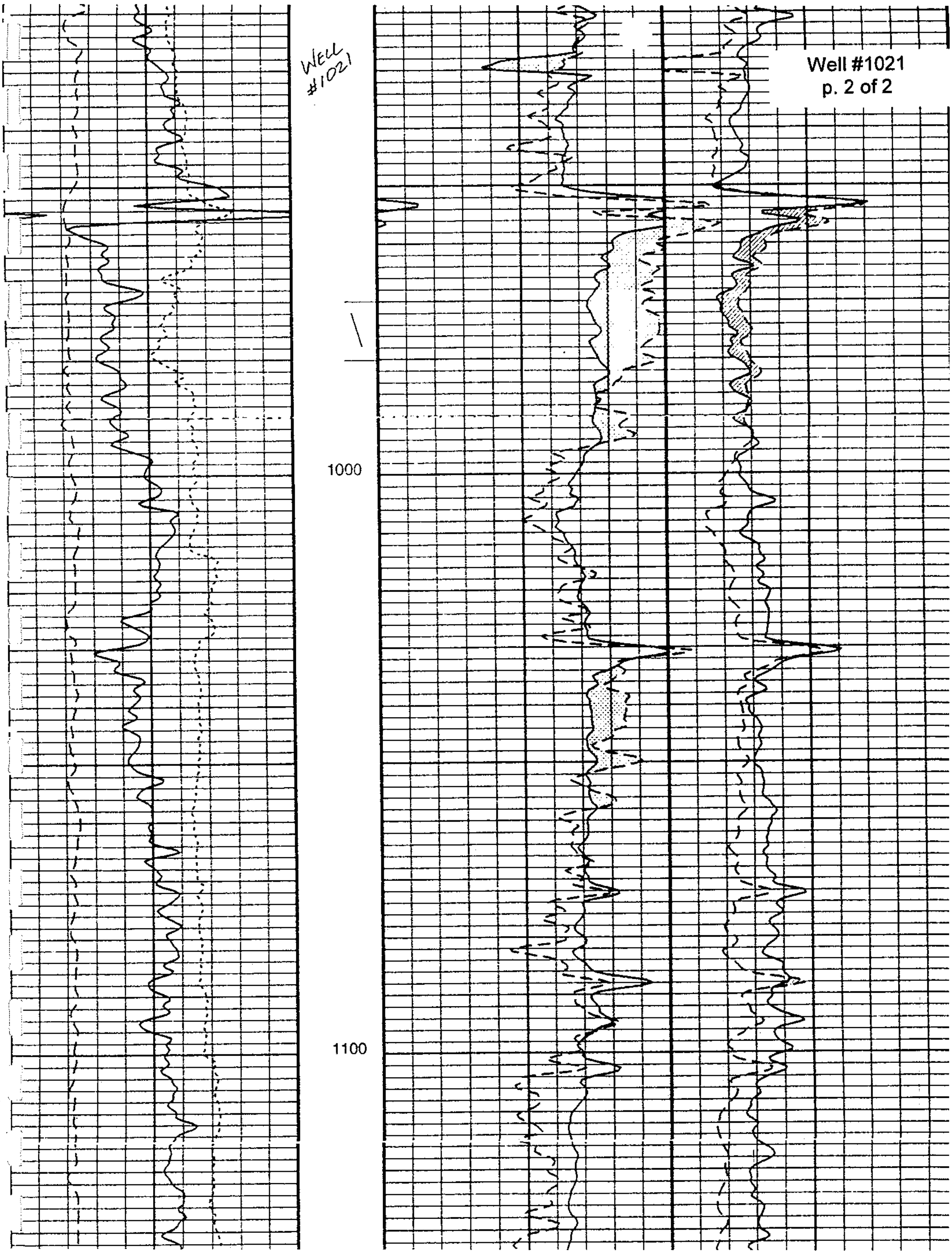
Caliper (CALI)
(IN) 14

Stuck Stretch (STIT)
0 (F) 50

Delta-T (DT)
200 (US/F) 100

Sonic Porosity (SPHI)
0.6 (V/V) 0




WELL #1021
Well #1021
p. 2 of 2
1000
1100

MCM

AIT-H	APCW-98Q1	LDT-D	APCW-98Q1
CNT-H	APCW-98Q1	SDT-C	rpcwx-1046
SGT-L	APCW-98Q1	TCC-B	APCW-98Q1

PIP SUMMARY

Time Mark Every 60 S

Well #1021

AIT-H 90 Inch Investigation (AHT90) 0.2 (OHMM) 20

AIT-H 60 Inch Investigation (AHT60) 0.2 (OHMM) 20

Tension (TENS) 10000 (LBF) 0

Tool/Tot. Drag From D3T to STIA

AIT-H 30 Inch Investigation (AHT30) 0.2 (OHMM) 20

SP (SP) -80 (MV) 20

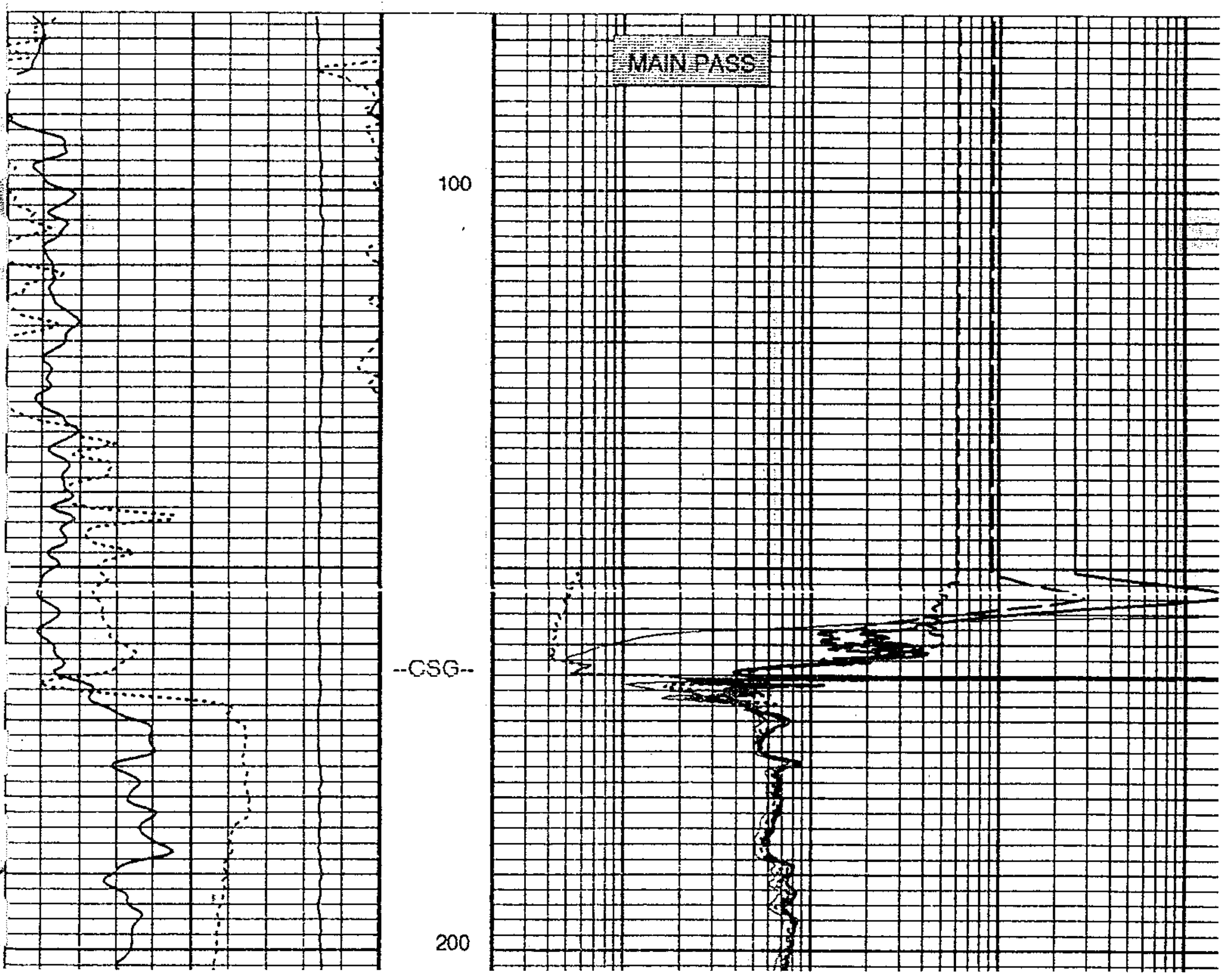
Cable Drag From STIA to STIT

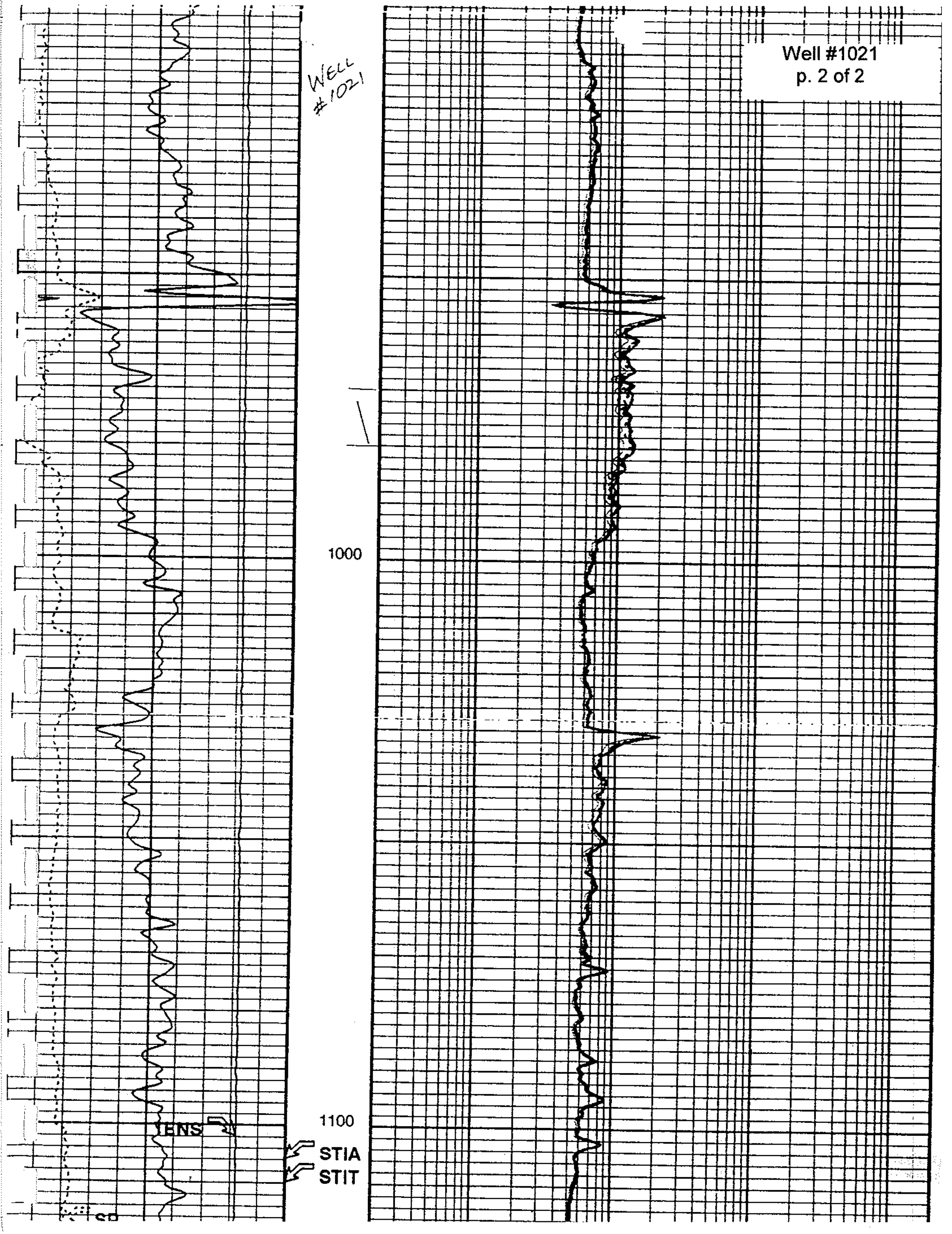
AIT-H 20 Inch Investigation (AHT20) 0.2 (OHMM) 20

Gamma Ray (GR) 50 (GAPI) 200

Stuck Stretch (STIT) 0 (F) 50

AIT-H 10 Inch Investigation (AHT10) 0.2 (OHMM) 20




Well #1021
p. 2 of 2
WELL #1021
1000
1100
TENS
STIA
STIT
SP

PIP SUMMARY

Time Mark Every 60 S

Well #1022
p. 1 of 2

MAIN PASS

Well #1022

Producibility
From DPHI to SPHI

Gas
From DT to TNPH

SP (SP)
-80 (MV) 20

Env.Corr.Thermal Neutron Porosity (TNPH)
0.6 (V/V) 0

Gamma Ray (GR)
50 (GAPI) 200

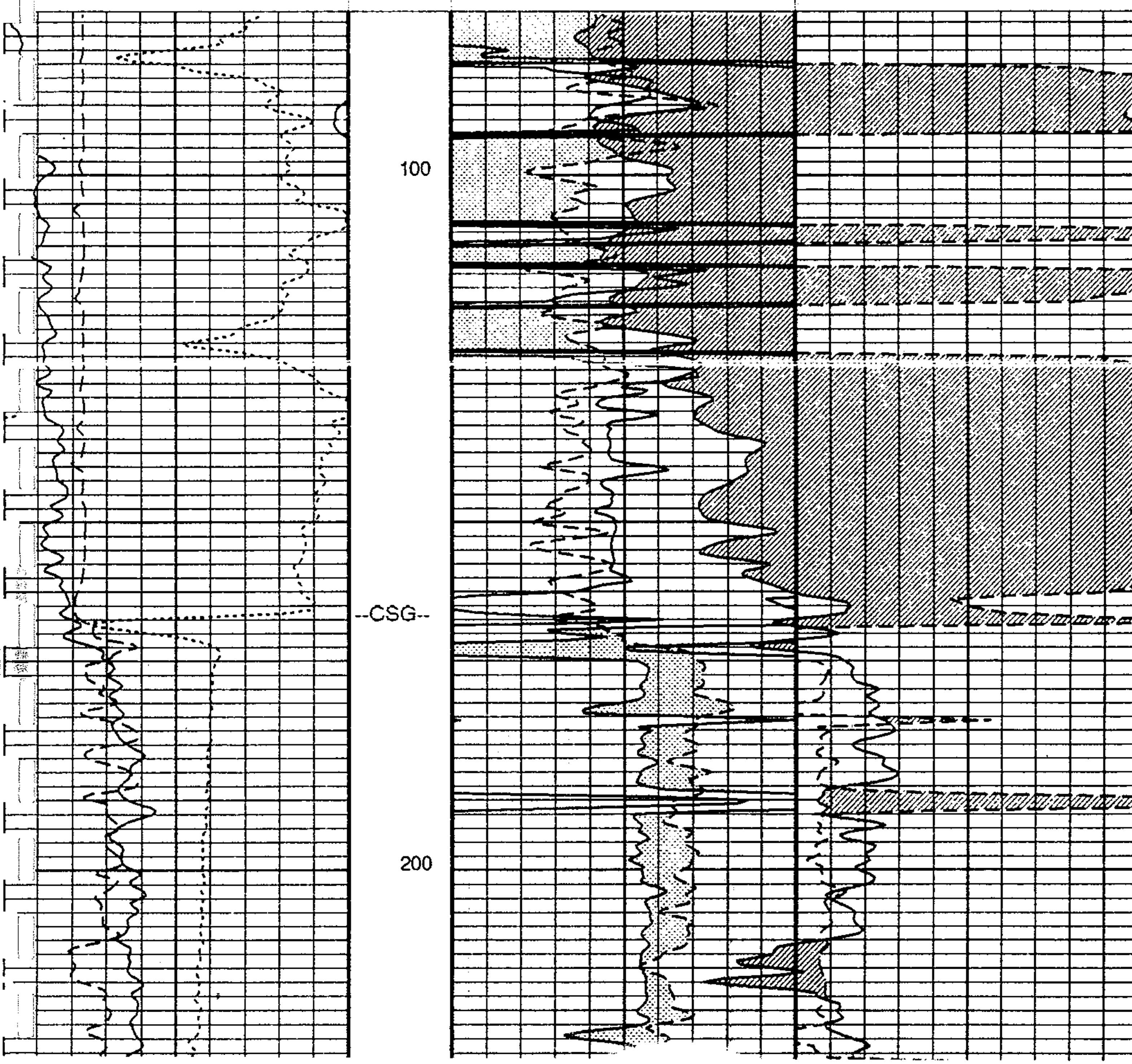
Density Porosity (DPHI)
0.6 (V/V) 0

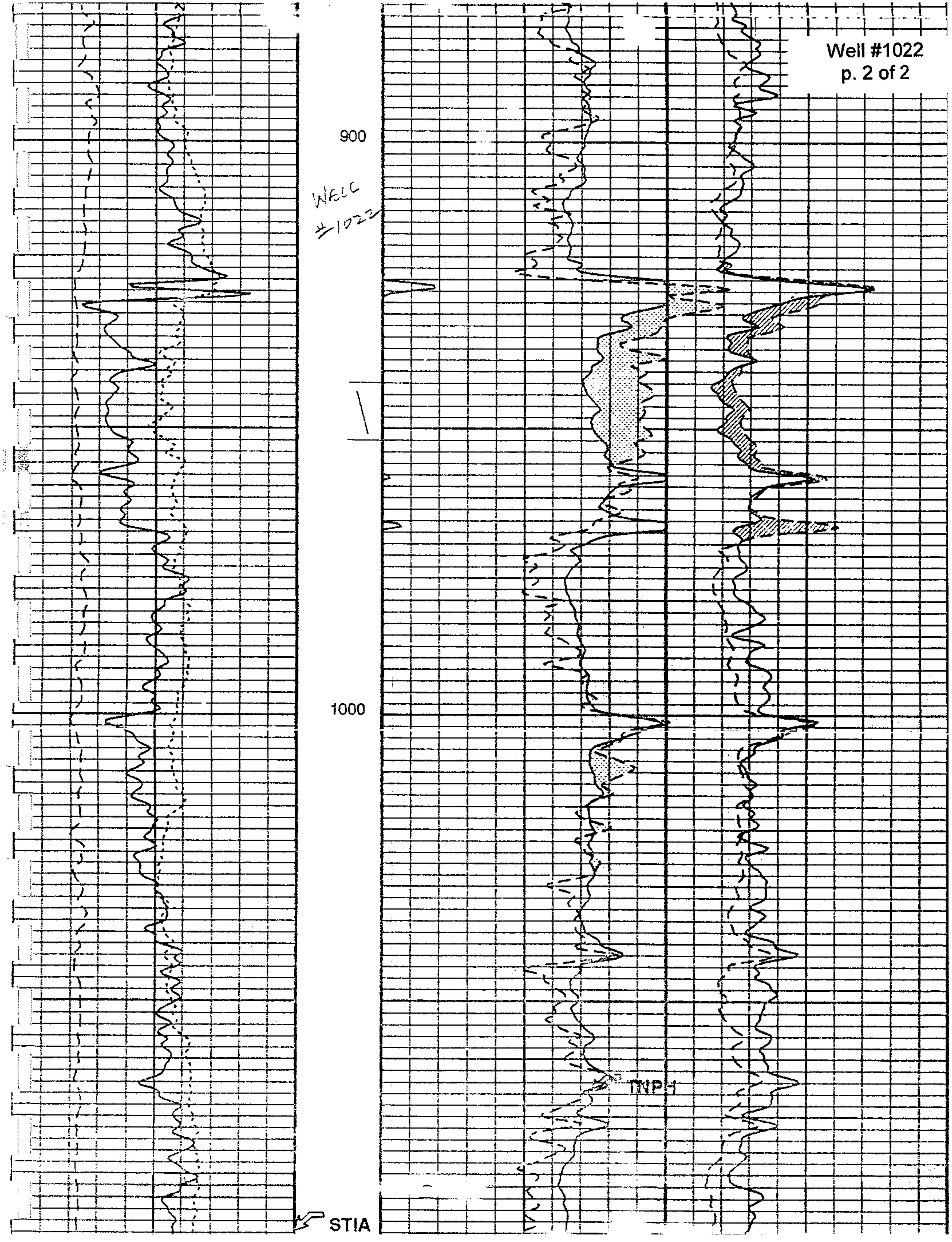
Caliper (CALI)
4 (IN) 14

Stuck Stretch (STIT)
0 (F) 50

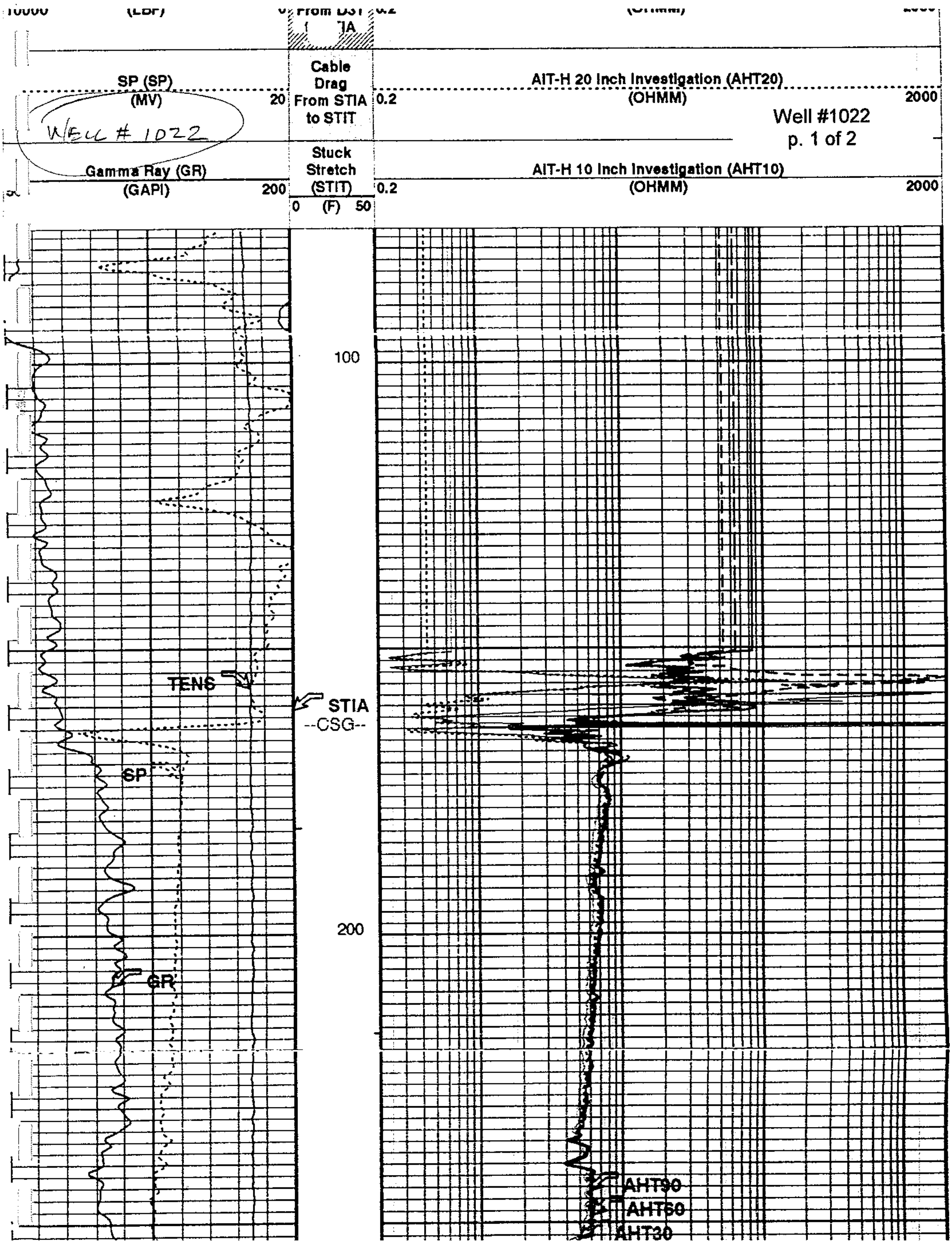
Delta-T (DT)
200 (US/F) 100

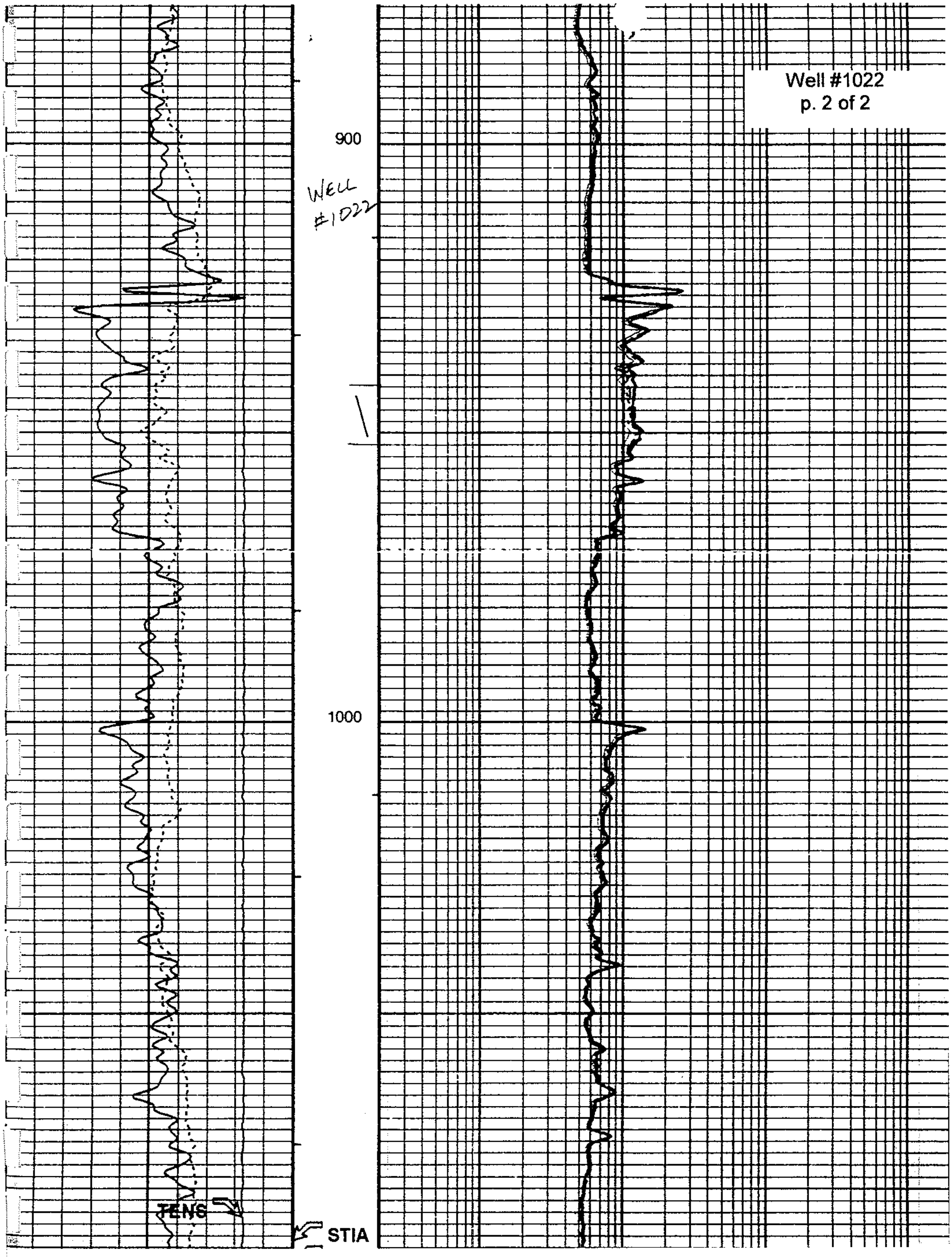
Sonic Porosity (SPHI)
0.6 (V/V) 0



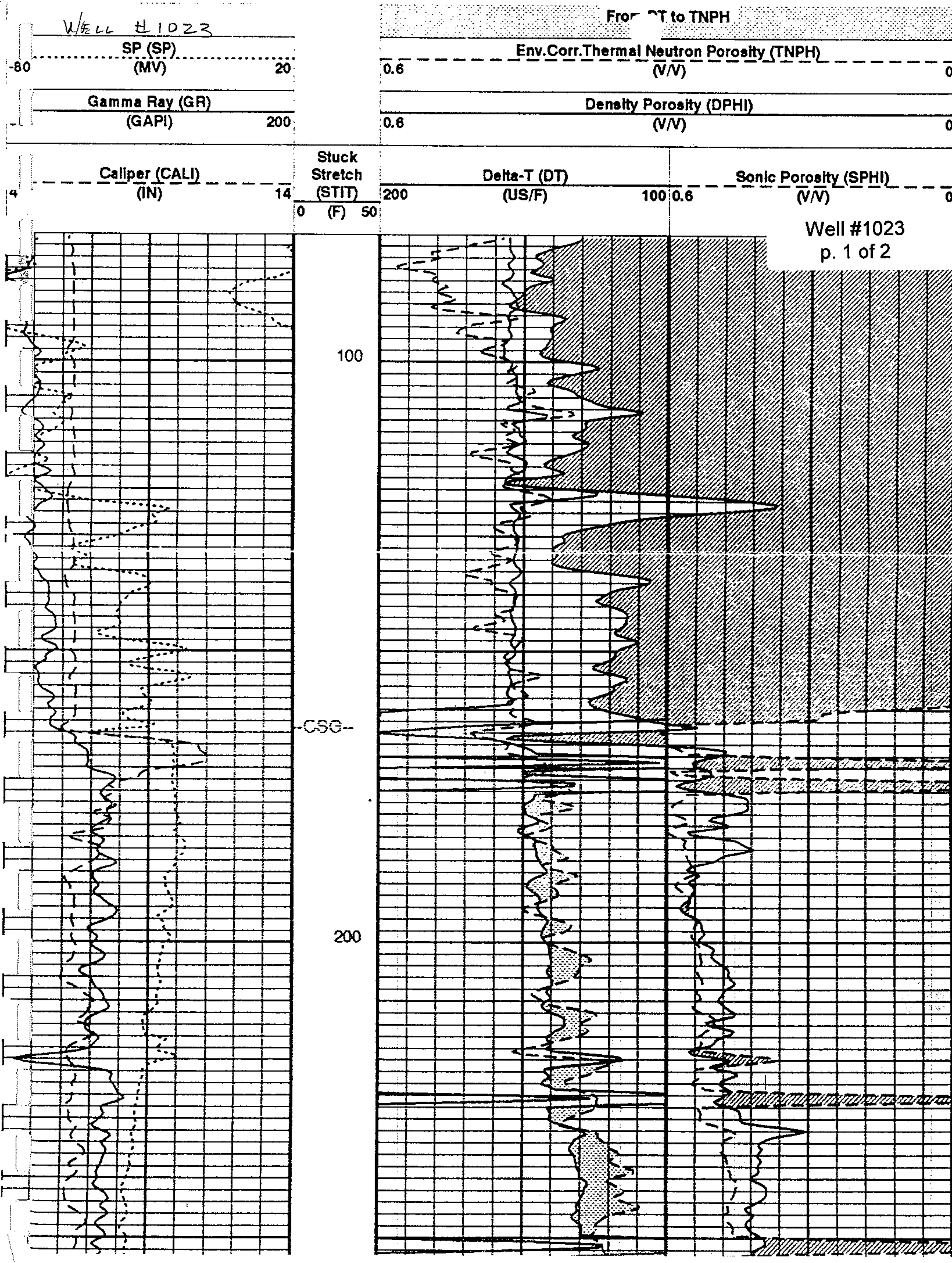


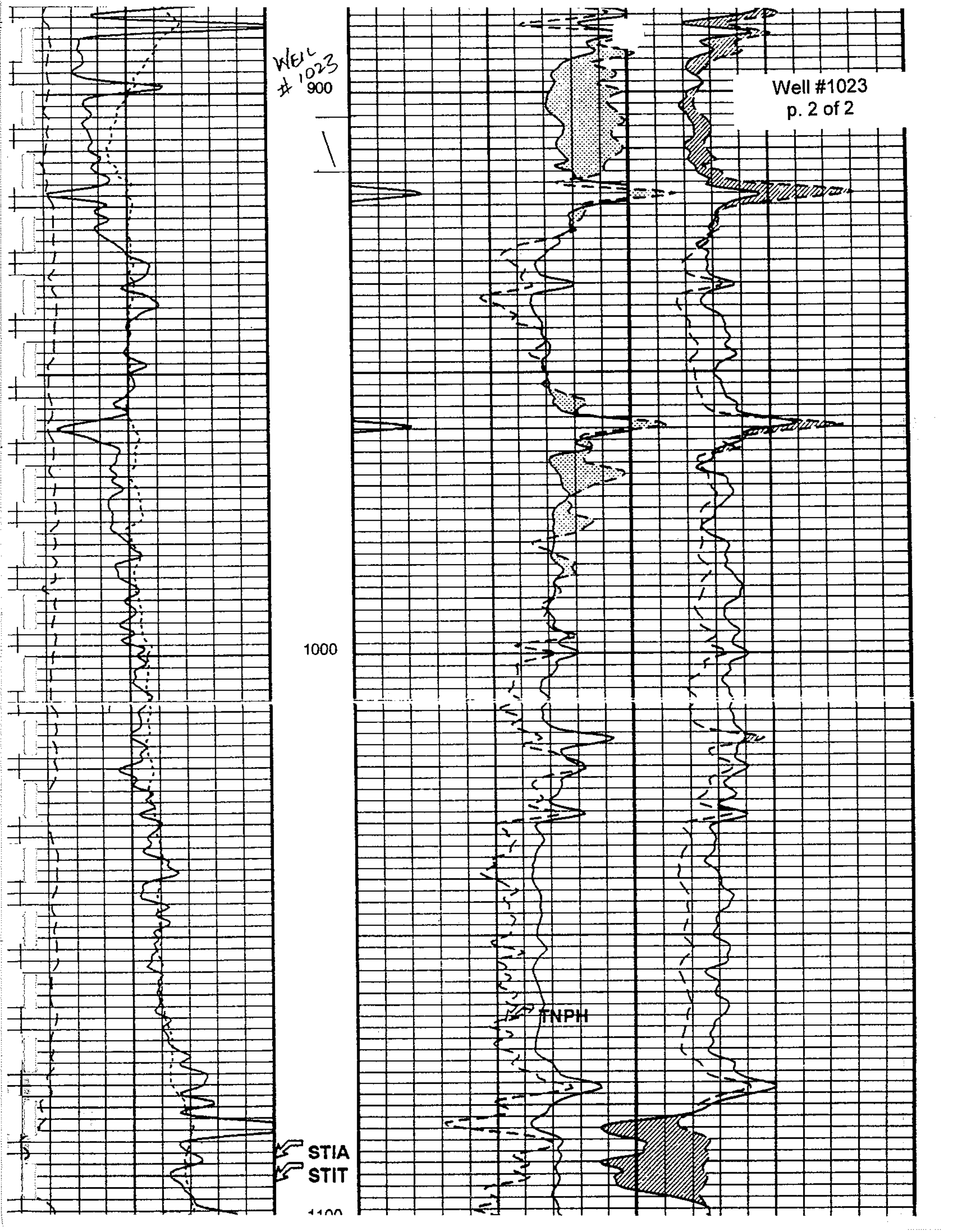
Well #1022
p. 2 of 2
900
WELL
#1022
1000
TNPH
STIA


10000
(LBF)
From DST
A
0.2
(OHMM)
SP (SP)
(MV)
20
Cable Drag From STIA to STIT
AIT-H 20 Inch Investigation (AHT20)
0.2
(OHMM)
2000
Well #1022
p. 1 of 2
WELL # 1022
Gamma Ray (GR)
(GAPI)
200
Stuck Stretch (STIT)
0 (F) 50
AIT-H 10 Inch Investigation (AHT10)
0.2
(OHMM)
2000
100
TENS
STIA
--CSG--
SP
200
GR
AHT90
AHT60
AHT30


Well #1022
p. 2 of 2
900
WELL
#1022
1000
TENS
STIA

Well #1023
p. 1 of 2




Well #1023
Well #1023
p. 2 of 2
900
1000
1100
TNPH
STIA
STIT

PIP SUMMARY

⊢ ..tegrated Hole Volume Minor Pip Every 1(

⊢ Integrated Hole Volume Major Pip Every 100 F3

⊣ Integrated Cement Volume Minor Pip Every 10 F3

⊣ Integrated Cement Volume Major Pip Every 100 F3

Well #1023
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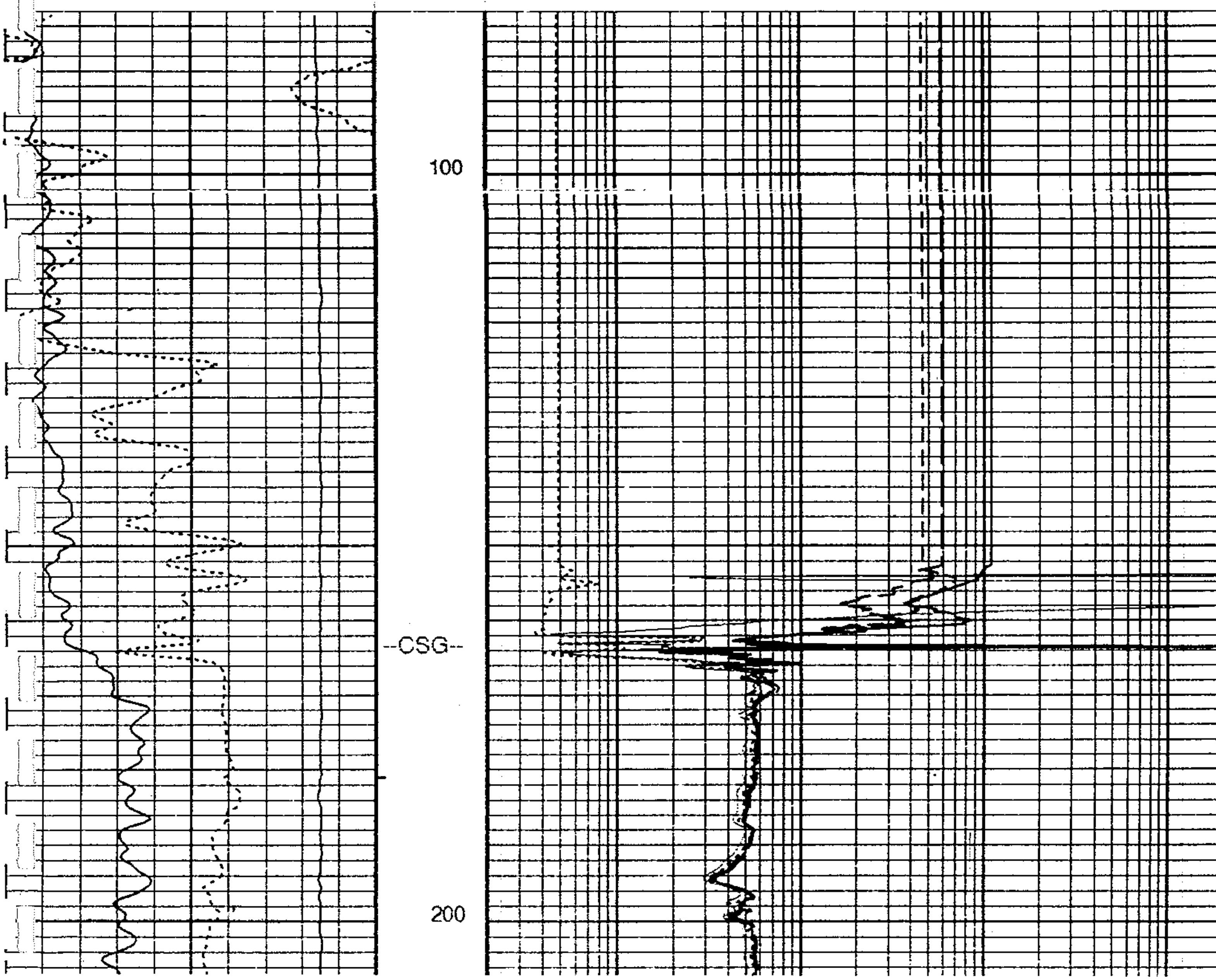
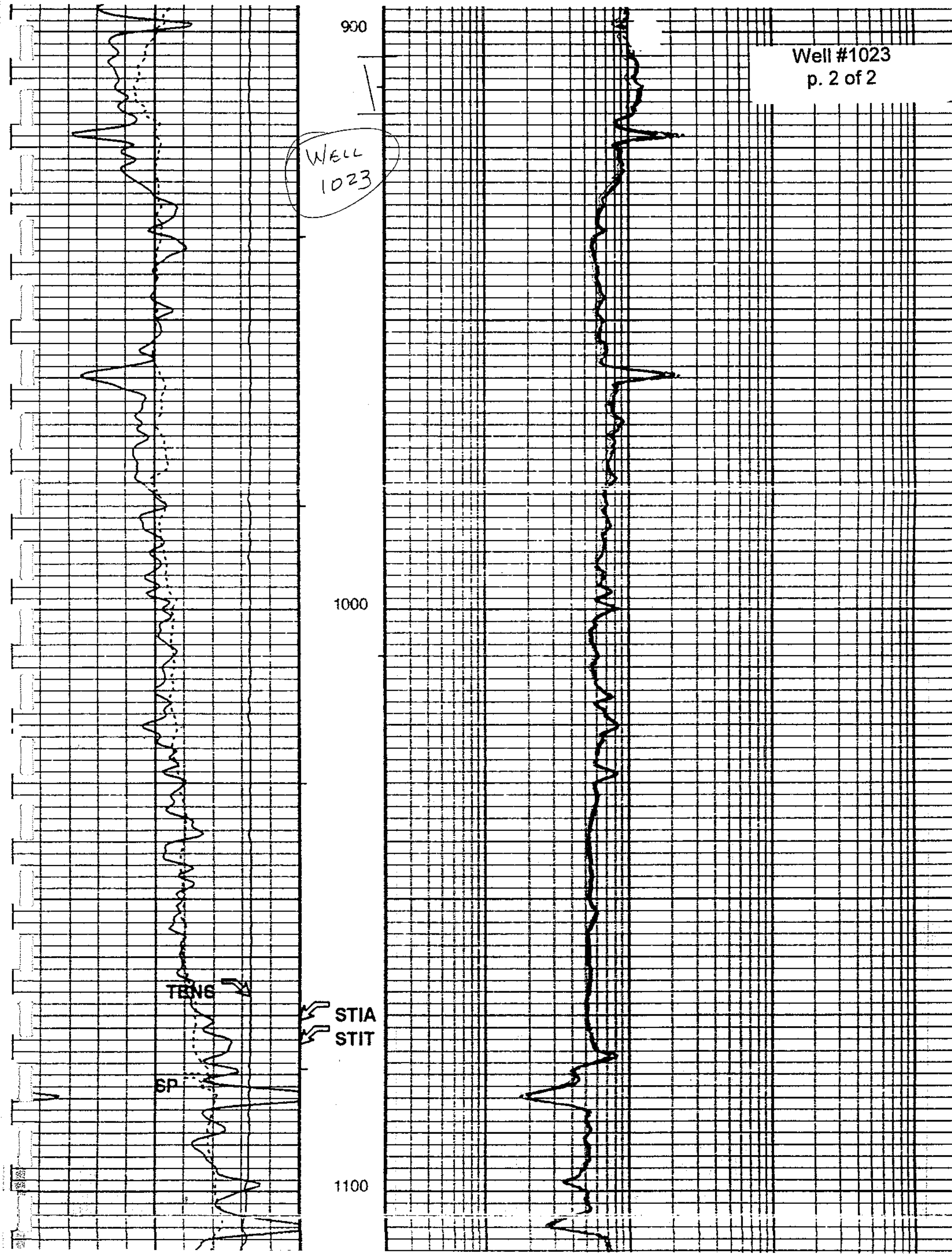
Time Mark Every 60 S

MAIN PASS

WELL # 1023

		AIT-H 90 Inch Investigation (AHT90) 0.2 (OHMM) 2000
		AIT-H 60 Inch Investigation (AHT60) 0.2 (OHMM) 2000
Tension (TENS) 10000 (LBF) 0	Tool/Tot. Drag From D3T to STIA	AIT-H 30 Inch Investigation (AHT30) 0.2 (OHMM) 2000
SP (SP) (MV) 20	Cable Drag From STIA to STIT	AIT-H 20 Inch Investigation (AHT20) 0.2 (OHMM) 2000
Gamma Ray (GR) 50 (GAPI) 200	Stuck Stretch (STIT) 0 (F) 50	AIT-H 10 Inch Investigation (AHT10) 0.2 (OHMM) 2000

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900
WELL
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TENS
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FIELD TESTING & OPTIMIZATION OF CO_2/SAND FRACTURING TECHNOLOGY
Group #7B – Blaine Co, Montana – Four Wells – Single Stage Treatments – Ocean Energy – September 2002

Final Report

By
RAYMOND L. MAZZA

Period of Performance
October 1, 1994 – November 30, 2004

Work Performed Under Contract No.: Contract #DE-AC21-94MC31199
"Field Testing & Optimization of CO_2/Sand Fracturing Technology"

For:
U. S. Department of Energy
National Energy Technology Laboratory
Morgantown, West Virginia

By
Petroleum Consulting Services
Canton, Ohio

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ABSTRACT

The demonstration of a 100% liquid free CO_2/sand stimulation process was executed on four producing, but unstimulated Candidate Wells (four stages) in the Upper and Middle Eagle Sands in Blaine Co, Montana in September, 2002. The process is unique in that because CO_2 is the only fluid which enters the formation and requires a specialized closed system, pressurized blender to mix up to 45,000 pounds of proppant with the CO_2. The CO_2 vaporizes at reservoir conditions and leaves a liquid-free proppant pack. The reservoir pressure in the Eagle Sands in the Test Area had diminished to 225 psi and was insufficient to expel the spent stimulation liquids used in conventional water-based treatments, and consequently there are a large number of unstimulated wells.

In-zone placed sand volumes ranged from 8,500 to 21,800 lbs and was proportional to the CO_2 volume, which ranged up to 835 Bbls and was limited by the maximum storage capability. All four wells had production improvements which after 22 months ranged from 3.1 to 54.1 MMcf and averaged 19.5 MMcf. The total incremental improvement is 77.8 MMcf.

I. ABSTRACT

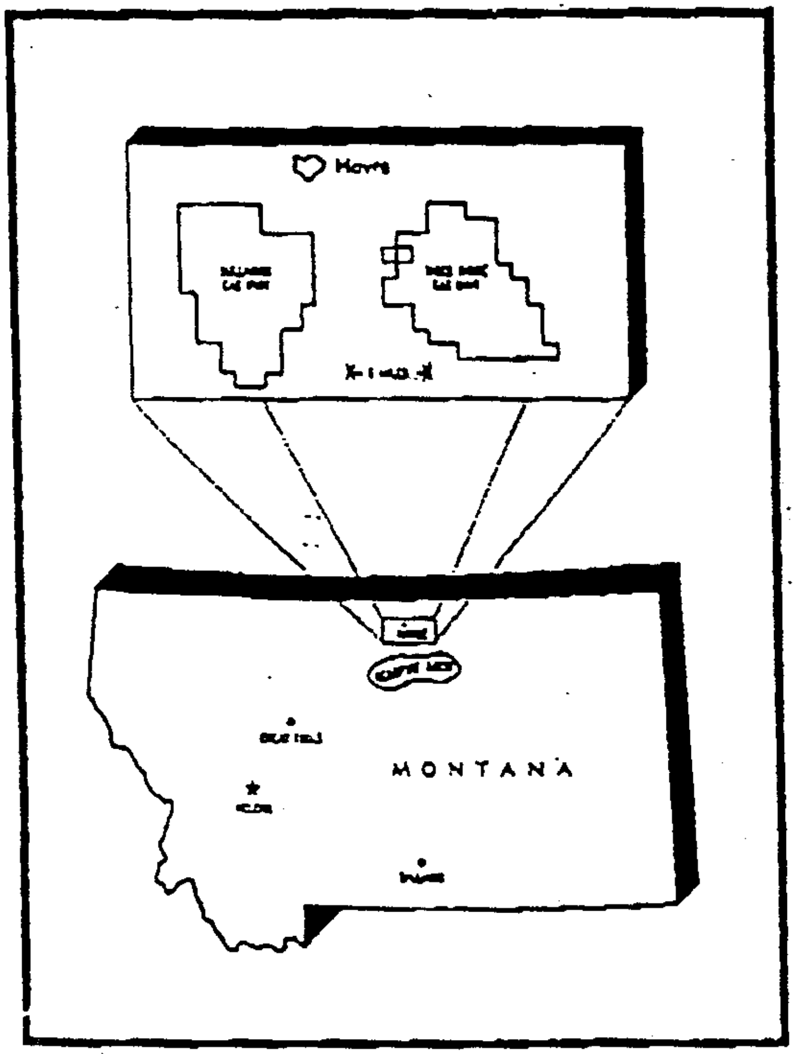
The demonstration of a 100% liquid free CO_2/sand stimulation process was executed on four producing, but unstimulated Candidate Wells (four stages) in the Upper and Middle Eagle Sands in Blaine Co, Montana in September, 2002. The process is unique in that because CO_2 is the only fluid which enters the formation and requires a specialized closed system, pressurized blender to mix up to 45,000 pounds of proppant with the CO_2. The CO_2 vaporizes at reservoir conditions and leaves a liquid-free proppant pack. The reservoir pressure in the Eagle Sands in the Test Area had diminished to 225 psi and was insufficient to expel the spent stimulation liquids used in conventional water-based treatments, and consequently there are a large number of unstimulated wells.

In-zone placed sand volumes ranged from 8,500 to 21,800 lbs and was proportional to the CO_2 volume, which ranged up to 835 Bbls and was limited by the maximum storage capability. All four wells had production improvements which after 22 months ranged from 3.1 to 54.1 MMcf and averaged 19.5 MMcf. The total incremental improvement is 77.8 MMcf.

II. INTRODUCTION

Ocean Energy, Inc. (Ocean) was the largest gas producing company in Montana and was the operator of record for approximately 650 producing gas wells in the north-central area of the state, southeast of Havre (Figure 1). These wells produce from a shallow, 1,500 to 2,000 feet Upper Cretaceous formation (Eagle Sandstone) which in certain pressure depleted segments of the Tiger Ridge field is irreversibly damaged by the liquids used in conventional nitrogen foam stimulations.

Figure 1



Because the reservoir pressure in the Tiger Ridge field had declined to approximately 225 psi, liquid-based stimulation techniques would not clean up following the treatment. The spent stimulation liquids remain trapped in the formation and significantly impede gas production. Additionally, there was also evidence of formation damage resulting from the invasion of drilling mud filtrate. These wells contain large gas volumes which could be produced more rapidly if a non-damaging stimulation process were available.

Ocean was therefore interested in the CO_2/Sand stimulation process, primarily because of the non-damaging, liquid-free aspects. And, was interested in the DOE cost-shared demonstration program to offset the expense and evaluate the non-damaging aspects of this treatment.

The accompanying information addresses the specifics of the Tiger Ridge field in Blaine County, Montana which identified six potential Candidate Wells for CO_2/Sand stimulation (Four were selected). The wells were producing, and following approval, were made ready and stimulated. Three required setting a plug to eliminate the lowermost perforations during the stimulation treatments and were removed following a post stimulation period.

III. BACKGROUND

Since the discovery of Eagle gas at Tiger Ridge by High Crest Oil in November, 1968, the industry has focused its attention on the development of this huge gas reserve and has conducted an extensive search for new fields. Gas reserves found on the north flank of the Bear Paw uplift were estimated to be in the magnitude of 500 billion cubic feet. "It is believed that additional exploration and development drilling will prove new reserves on the north side of the uplift and a major new producing area on the south flank. It is not unrealistic to estimate the probable reserves on the flanks of the Bear Paw uplift in excess of 1 trillion cubic feet of gas."

The Tricentrol United States, Inc. initially operated the Tiger Ridge and Bull Hook Gas Units in Blaine and Hill Counties of north-central Montana. The area of interest lies south of Havre, Montana, and encompasses approximately 112,000 surface acres of unitized Eagle Sandstone Formation in the two units as shown in Figure 1. The Eagle sandstones are approximately 1300 feet deep and range in thickness from 5 feet to over 150 feet of net gas pay, with the average approximately 30 to 40 feet.

The discovery well was the O'Neil 1-8 in the SE/NE of Section 1, 31N-17E Blaine County, drilled during September, 1966. The well was drilled through the Eagle Sandstone at 1340 feet and found to be productive. This indicated the possibilities of commercial gas production in the area.

IV. METHODOLOGY

The methodology employed in this demonstration differs from that used in previous evaluations. In the previous demonstrations the Candidate Wells were new wells with no production history, and in those evaluations the post stimulation production from the Candidate Wells was compared with that from nearby producing Control Wells.

Because the Candidate Wells in this demonstration were unstimulated and had a previous production history, the production which occurred subsequent to the CO_2/sand stimulation was compared with that prior to the treatment. This evaluation enabled the response to the stimulation to be compared on a "before and after" per-well basis and eliminated reservoir differences.

The evaluation of the produced gas was made through the use of pre stimulation production rates which is the basis for back-extrapolation to the earlier times in the producing life. This technique results in an uninterrupted production sequence, and thereby eliminates the unknowns associated with shut-ins, missing data, higher production rates resulting from the pressure build-up associated with shut-ins, etc. It also, and perhaps more significantly enables an unencumbered assessment to be made in that it removes the bias created by the higher rate "flush" production rates frequently recorded early in the producing life. The flush production is a result draining the more permeable portions of the formation which can be increased by the presence of natural fractures.

A. Mathematical Analog of Production Data

The procedure to remove flush or missing production volumes utilized a fit of a mathematic equation of the later time, but pre stimulation production.

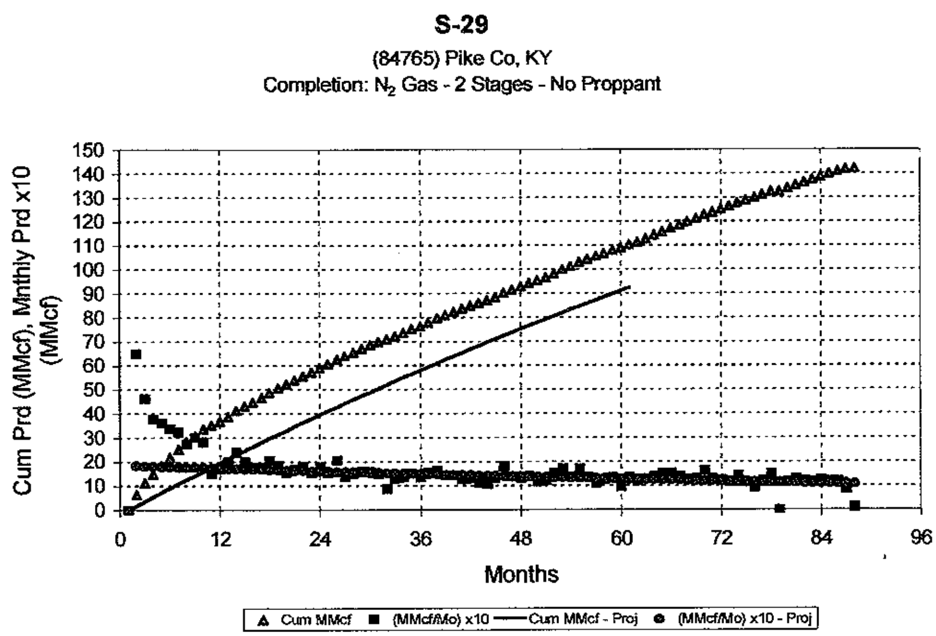
B. Missing Data

This process can also provide a significant benefit where there is missing production data. Also, in instances where there is only a very limited knowledge of the early production histories or where there is co-metered gas production can benefit as well.

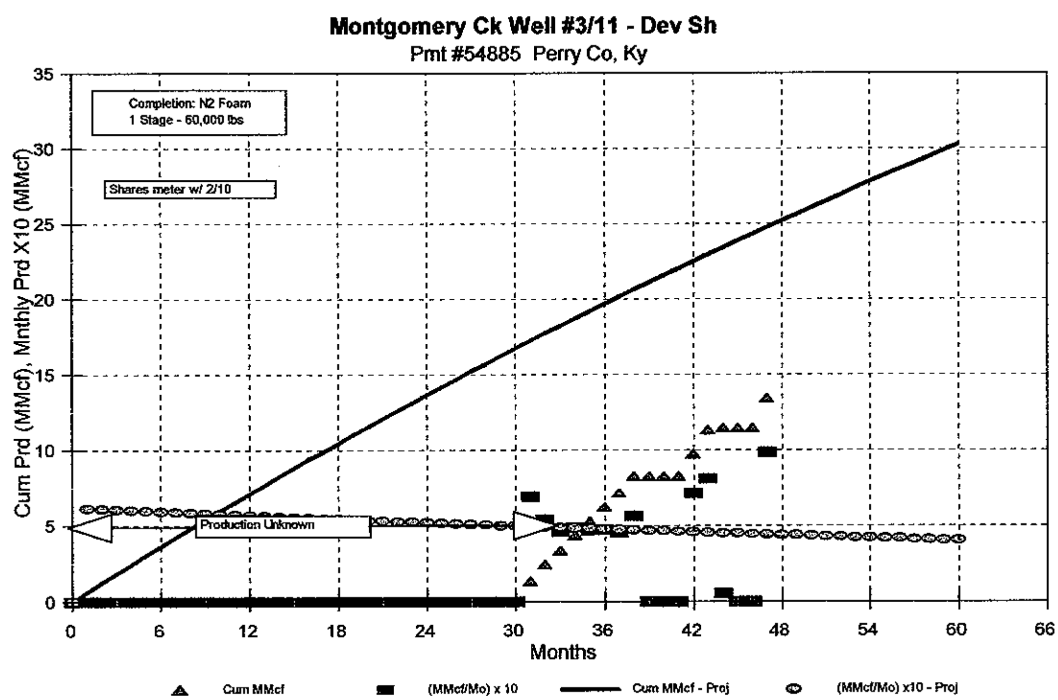
C. Examples

The following examples demonstrate the procedure utilized to remove the gas produced during the flush production period which in this case lasted approximately 13 months.

The actual produced gas volume was 41 MMcf while the projected volume was 23 MMcf or a difference of 18 MMcf. The projected five year cumulative production is 92 MMcf whereas the actual production volume measured was 110 MMcf.



In the second example there was no production data available for the first 29 months, additionally the available data included two shut in periods which are followed by flush production. By utilizing a mathematic fit of the steady state production data a realistic projection of the early time production resulted. The limited data set was then utilized, and the bias resulting from the flush production periods following the shut in periods was removed.



In removing the effects of the flush production volume a more realistic assessment of the response to the different stimulation types resulted. The production plots for each well including the actual and projected values are included.

V. PRODUCING HORIZON

The Eagle Formation can be divided into three units: the upper, middle and lower sandstones. The upper sandstone (Figure 2) attains a thickness of over 75 feet and is the primary gas producing reservoir on the flanks of the Bear Paw uplift. The middle sandstone, which develops a thickness in excess of 75 feet, (Figure 3) is separated from the upper unit by a 10 to 40 foot thick shale bed. It is an excellent reservoir that only produces in those fault blocks where the upper sandstone is completely filled with gas or where the upper sandstone is not developed. The lower sandstone is thinner and less widespread than the other units. It is normally separated from the middle sandstone by a thin shale, but locally the two combine. The lower sandstone only produces in two wells on the south edge of the Tiger Ridge field, and in both of these wells, the upper and lower sands are completely full of gas.

note: This information has been excerpted from literature prepared some years prior and there could be, and likely are more than two wells now producing from the lower Eagle member.

Figure 2

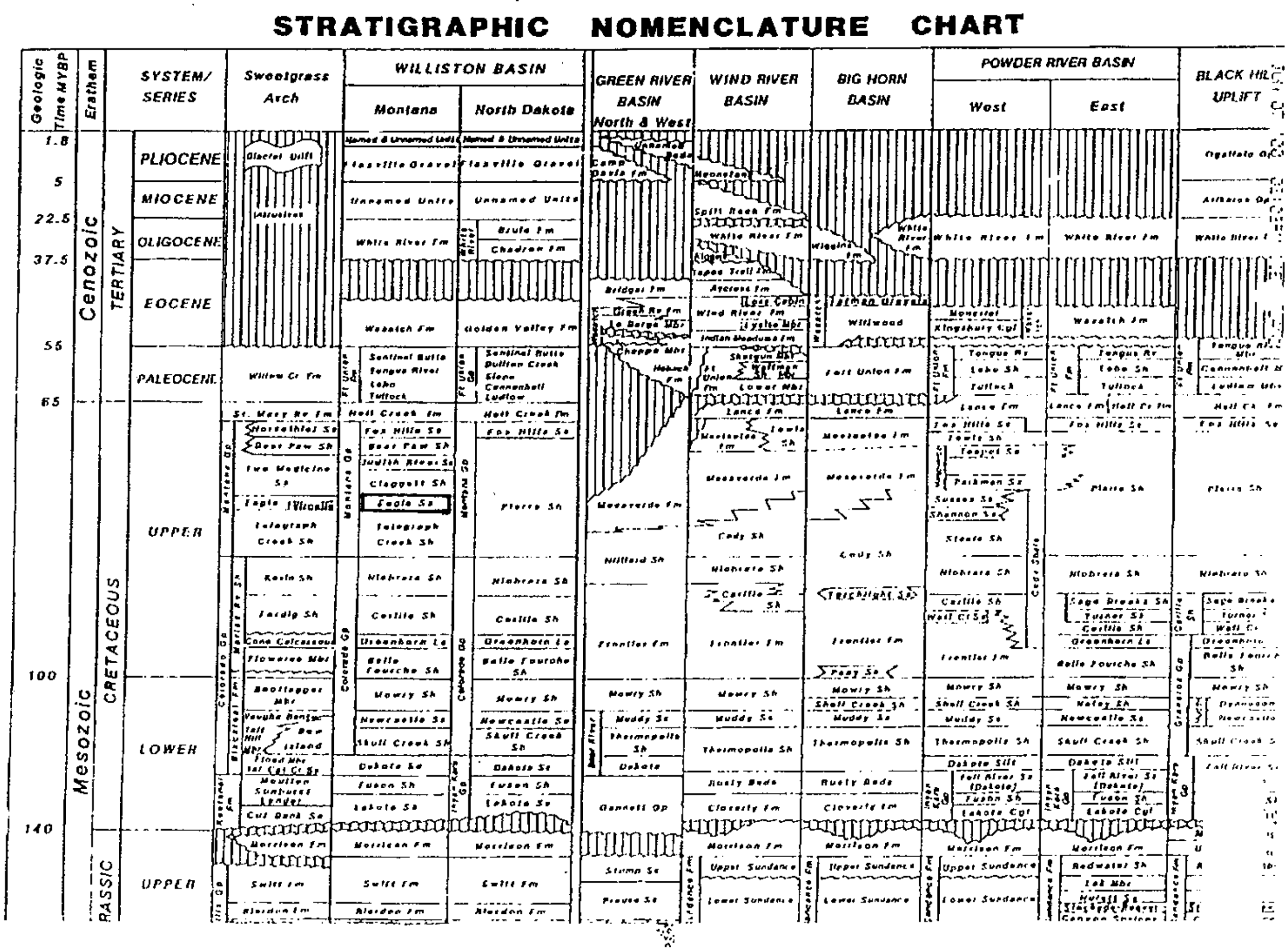
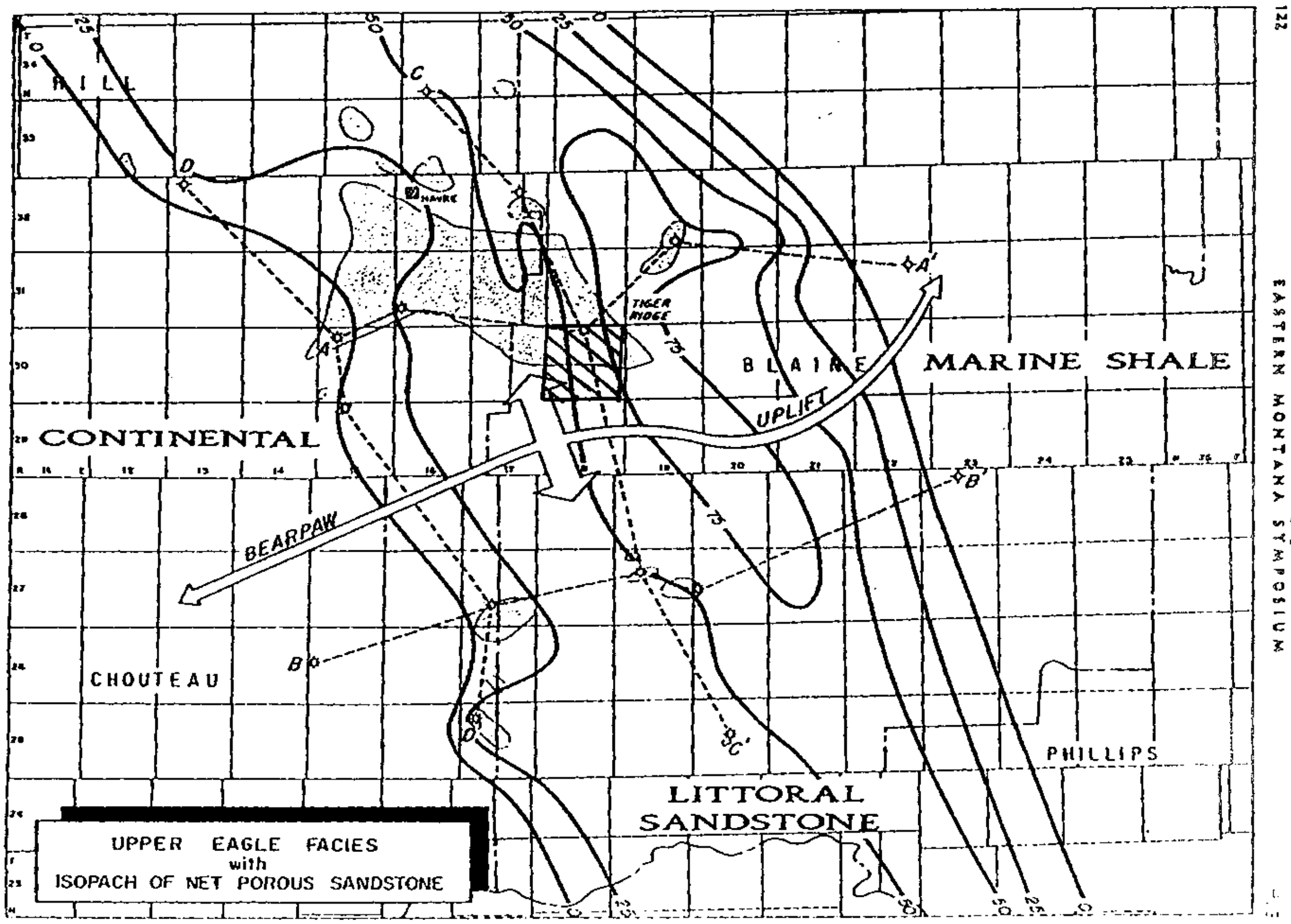

STRATIGRAPHIC NOMENCLATURE CHART
Geologic Time MYBP
Erathem
SYSTEM/ SERIES
Sweetgrass Arch
WILLISTON BASIN
Montana
North Dakota
GREEN RIVER BASIN North & West
WIND RIVER BASIN
BIG HORN BASIN
POWDER RIVER BASIN
West
East
BLACK HILLS UPLIFT
Cenozoic
Mesozoic
TERTIARY
CRETACEOUS
PLIOCENE
MIOCENE
OLIGOCENE
EOCENE
PALEOCENE
UPPER
LOWER
1.8
5
22.5
37.5
55
65
100
140

Figure 3



Isopach map of net porous sandstone in upper unit of Eagle Sandstone Formation.

VI. GEOLOGY

The Eagle Sandstones are within the Montana group of the Santonian stage (82-86 my) of the Upper Cretaceous series and could be considered as a traditional sand reservoir. It is overlain by the Martin Sandstone, which is a newly rediscovered zone contained within the Niobrara sequence (Figure 4).

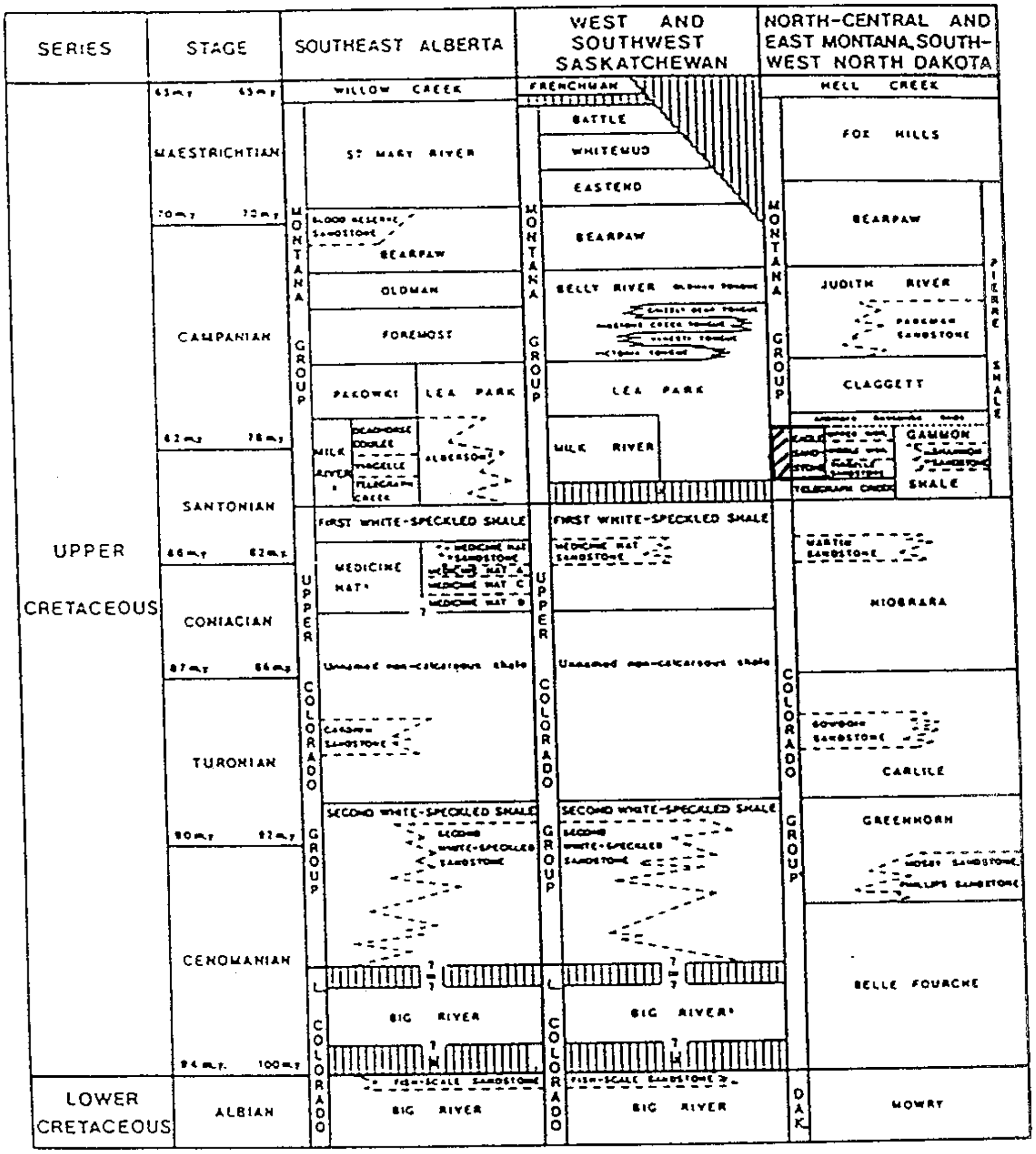
A. Stratigraphy

The Eagle Formation is composed of a series of thick, porous littoral sandstones which were deposited during the first major eastward regression of the Upper Cretaceous sea. The individual sandstone members are very extensive and for all practical purposes form blanket reservoirs which extend from Canada southeast to the outcrop on the north flank of Cat Creek anticline. The white, salt and pepper, fine grained sandstones are sub-angular to sub-rounded and contain glauconite with some pyrite and lignite. They have excellent porosity and permeability.

In the eastern part of this region, the Eagle is underlain by the silty shale's of the upper Colorado Group. In the western part, it is underlain by the Virgelle Sandstone, which is a sandy facies of the upper Colorado.

After deposition of the Eagle Formation the seas transgressed the entire region and deposited the gray shale's of the Claggett Formation. The Claggett is believed to be the primary source of the gas produced from the Eagle Formation. The overall stratigraphy of the area is ideal for the generation and accumulation of hydrocarbons.

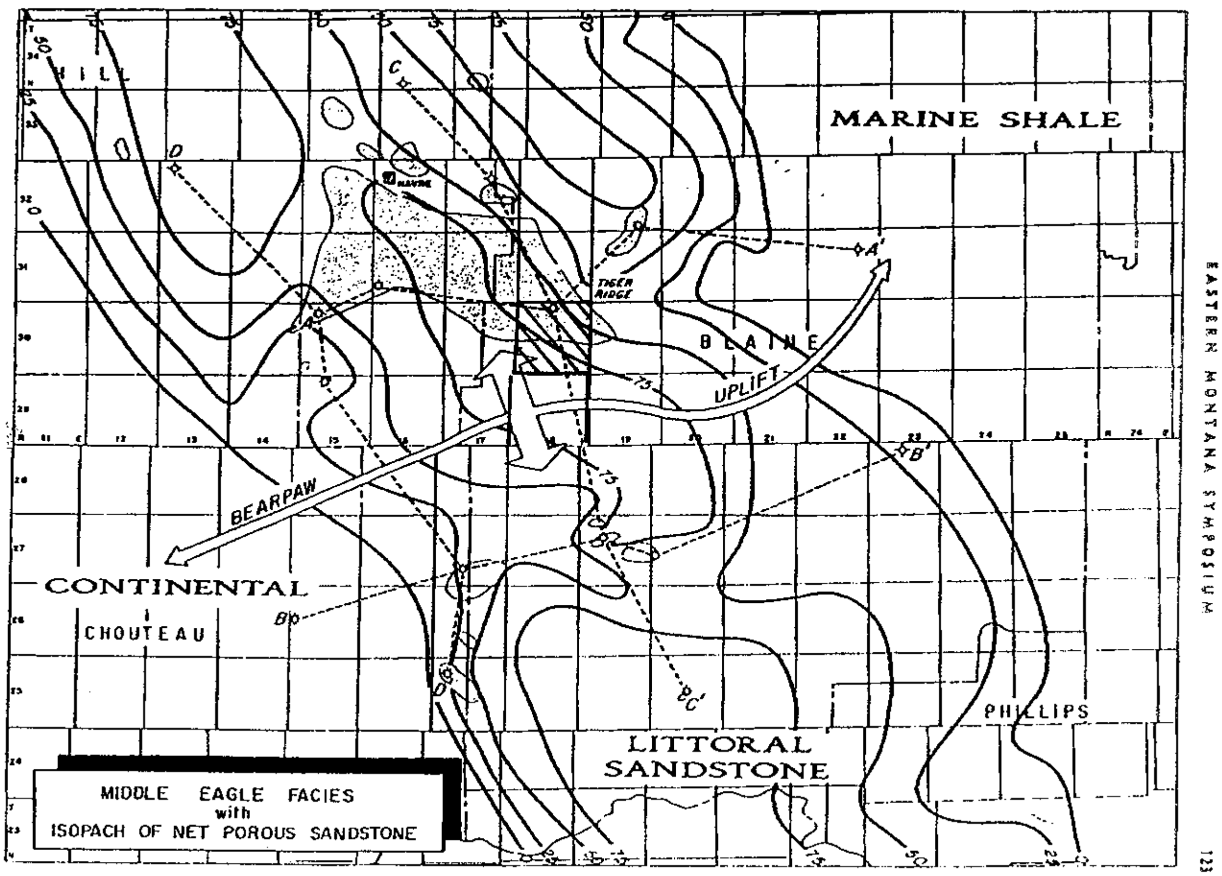
Figure 4


SERIES
STAGE
SOUTHEAST ALBERTA
WEST AND SOUTHWEST SASKATCHEWAN
NORTH-CENTRAL AND EAST MONTANA, SOUTH-WEST NORTH DAKOTA
UPPER CRETACEOUS
LOWER CRETACEOUS
MAESTRICHTIAN
CAMPANIAN
SANTONIAN
CONIACIAN
TURONIAN
CENOMANIAN
ALBIAN
WILLOW CREEK
ST MARY RIVER
BEARPAW
OLDMAN
FOREMOST
PAKOWKI
LEA PARK
MILK RIVER
ALBERSON
FIRST WHITE-SPECKLED SHALE
MEDICINE HAT
Unnamed non-calcareous shale
SECOND WHITE-SPECKLED SHALE
BIG RIVER
FISH-SCALE SANDSTONE
FRENCHMAN
BATTLE
WHITEMUD
EASTEND
BELLY RIVER
HELL CREEK
FOX HILLS
JUDITH RIVER
CLAGGETT
GAMMON
SHALE
NIOBRARA
CARLILE
GREENHORN
BELLE FOURCHE
MOWRY
MONTANA GROUP
UPPER COLORADO GROUP
COLORADO GROUP
COLORADO
PIERRE SHALE
DAK

B. Structure

The Bear Paw uplift plays a major role in the entrapment of gas in the Eagle Formation. For this reason it is important to understand the structural development of the area. As can be seen from Figure 5, the northwest-southeast trending Eagle sandstones cross the present-day uplift. This uplift probably formed in early Laramide time, however there is some evidence that it may have begun to form as early as Eagle time. From its inception, the Bear Paw uplift was a major focal point of gas entrapment. Evidence which is preserved indicates that a gas field of enormous proportions accumulated before later deformation destroyed it.

Figure 5



Isopach map of net porous sandstone in middle unit of Eagle Sandstone Formation.

As the Bear Paw uplift continued to grow, intensive igneous activity occurred in the central part. This igneous activity, in combination with a very weak shear plane located just above the Greenhorn Formation, caused extensive land sliding on both the north and south flanks. Subsurface data show a large area on the south flank where volcanic flows rest on the lower Colorado Shale. This is the area where the landslide broke away from the uplift when it slid to the southeast. Similar conditions seem to exist on the north flank, but are not as well defined. Deeper well penetrations indicate that faulting does not extend to depth, and that a normal (unfaulted) structural configuration exists below the Greenhorn.

The landslide on the south side of the uplift is the easiest to define, since much of the deformation can be mapped on the surface. The landslides carried with them the down dip edges of the paleo-gas field. This gas was then re-entrapped in normal fault blocks which occurred at the head of the slides. The Bear Paw uplift continued to rise, and erosion, which stripped the Eagle Formation from the crestal part, destroyed a major portion of the old gas field. It is believed that additional gas reserves will be found high on the flanks of the Bear Paw uplift, within the normal fault block areas at the head of the old landslides. Numerous traps are also present in the thrust fault segments which occur at the toe of the slide areas, but to date these traps have contained only small gas pools.

VII. FIELD

Because the wells in the Tiger Ridge Field are shallow, 1,500-2,000 feet, and are relatively inexpensive to drill and complete, they provide good investment returns even at a 50% success rate. The reservoir is naturally fractured as a result of the Bear Paw uplift and further it is compartmentalized by igneous intrusives, and as a consequence the EUR's vary significantly.

VIII. RESERVOIR

A. Porosity, Permeability, Thickness, and EUR

The porosity ranges from 15 to 25 percent with permeability's ranging from 10 to 60 md and the completed thickness for both the Upper and Middle Eagle Sands approaches 100 feet, depending on the gas/water contact. The newer wells produce approximately 150 Mcf daily and have EUR's on the order of 400 MMcf. Older wells which were drilled at virgin pressure had EUR's ranging generally up to 2BCF.

B. Reservoir Pressure and Temperature

The lower pressure reservoir portions where the Candidate Wells are located are in the Tiger Ridge field which is north of the Bear Paw mountains. This lower pressure section has been extensively drilled, are is now pressure depleted (225 psi). It generally will not clean up following the liquid-based stimulation treatments. Whereas the areas south of the Bear Paw mountains have significantly greater pressure, 500 psi and can be successfully stimulated with nitrogen foam.

The reservoir pressure as measured by shut-in wellhead pressures in the Candidate Wells ranges from 175 to 297 psi in the test area:

Well	S - #	Pi (Psi)
T30N-R18E		
S-B Ranch	02-05	
Blackwood	06-09	222
Kane	05-08	175
Kane	05-05	297
Kane	04-12	204
S-B Ranch	02-11	225

And, the reservoir temperature is approximately 70 degrees F.

C. Gas Properties

The gas composition is made up of methane, ethane, and nitrogen. There are no sulfur gases nor carbon dioxide present:

Component	Mol pct
C_2H_4	96.5
C_3H_8	0.5
CO_2	0.0
N_2	3.0
Sulfur Compounds	0.0
Total	100.0

which results in a biogenic gas with a calorific value of 983 BTU per cubic foot (wet basis).

D. Sensitivity to Stimulation Liquids

This reduced pressure, relatively* dry gas reservoir has a long history of being successfully stimulated with conventional water-based stimulations. Unfortunately, because of the reduced reservoir pressure, the spent stimulation liquids remain in the formation for an extended period and thereby reduce the permeability to gas. The sensitivity of this reservoir to liquids is a consequence of the inability of the reduced pressure to displace the stimulation liquids as opposed to the more conventional conditions of formations reactivity such as swelling shale.

* The completion practices are to perforate the Upper Eagle and the Middle Eagle Sand above any liquid as indicated by the electric logs. The wells do produce very slight volumes of water which are lifted with velocity strings, and any entrained liquid is carried in the gas and does not collect in the separators nor is there any liquid in the tanks.

IX. CO_2 CHARACTERISTICS

The reservoir temperature is 70° F and the pipeline pressure is 15 to 18 psi. The CO_2 will vaporize under these conditions, requiring approximately 29 MM BTUs per 100 tons of liquid CO_2 (Figure 6).

Pt # Location	Press (psig)	Temp (°F)	State	Density (lb/cuft)	Enthalpy BTU/lbm
PUMPING*					
1 Well head	3000	0	SL	66.7	-3900
2 Perfs (@1,400 ft)	3636	20**	SL	64.9	-3892
NOT PUMPING					
3 Perfs***	786	20	SL	61.9	-3894
4 Formtn***	225	-18	SL	65.4	-3906
SI/ Flow back			SL>SV SV>SHV		
5 Formtn	225	70	SHV	1.90	-3761
6 Perfs	23	70	SHV	0.32	-3755
7 Well head	17	60	SHV	0.25	-3753
* Pumping through 4.50 in casing at 32 bbls per min					
** Heat gain through casing at 32 bbls per min = $278(10)^3$ BTUs (68 BTU/sqft @ LMDT = 2.6°F)					
*** At the instant that the pumping is terminated -3906-(-3761) = -145 BTU/lb = -$290(10)^3$ BTU/ton					

Heat required to vaporize = $-290(10)^3$ X 91 = $-26.39(10)^6$ BTU
Temp diff = 70-20 = 50 deg F
Thermal Conductivity of CO_2 @ 510 deg R @ 100 psi = 0.01 (Btu/hr-sq ft)/(Deg F/ft)

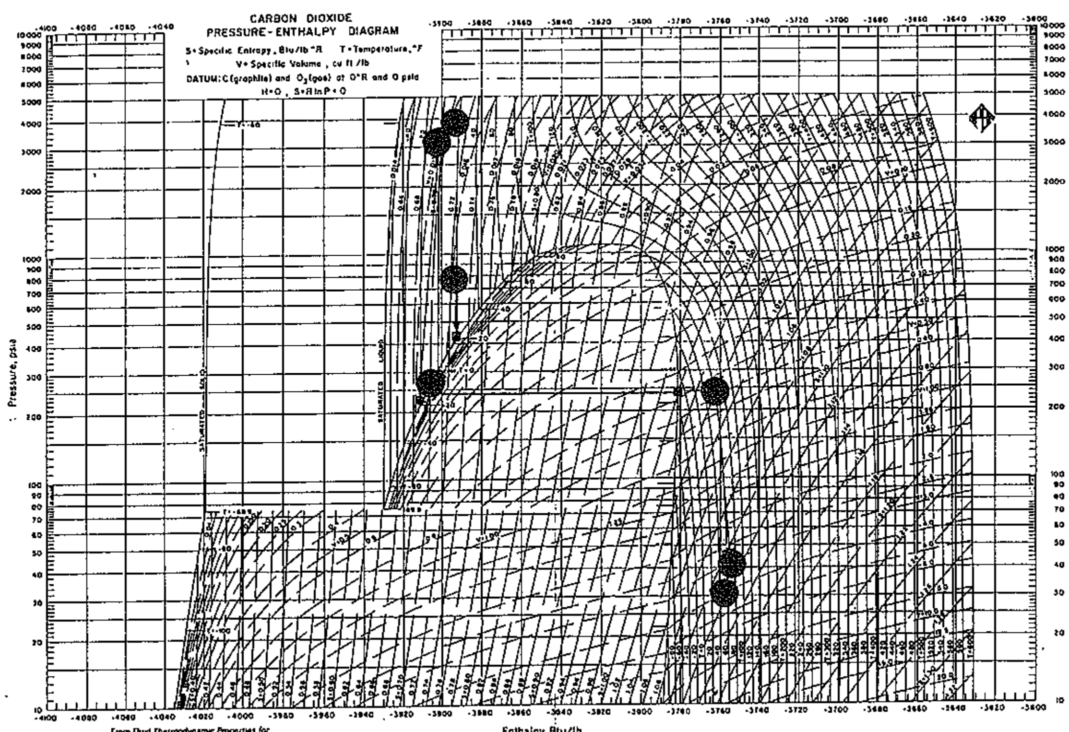


Figure 6

Based on the prediction that the liquid CO_2 will, immediately following the pumping activity, quickly diminish to approximately 786 psi, and then will further drop to the reservoir pressure of 225 psi. This pressure reduction will cause the CO_2 temperature to diminish from +20 F to -18 degrees F. The state of the CO_2 will remain in a liquid phase and it will continue to gain heat at constant temperature through the mixture range. The temperature will begins to increase only after all of the liquid has vaporized.

The CO_2 will at that point be completely vaporized and will continue to increase in temperature until it reaches the formation temperature of 70 degrees F. The majority of the heat will be consumed in changing the phase from a liquid to a gas.

An inquiry was made into the freezing point of the formation water. Ocean's field operations personnel indicated that the water is very fresh, and that it will freeze at 30 degrees F. There was concern that the formation water would freeze. This concern was discussed with Ocean, and calculations on the porosity, water saturation, and heat requirement resulted in Ocean relating that the risk of formation damage from the freezing was reviewed and considered to be minimal.

X. CONVENTIONAL STIMULATION TREATMENTS

Where the reservoir pressure is sufficient to displace the spent stimulation liquids from the reservoir as it still is south of the Bear Paw Uplift, a conventional stimulation generally utilizes a 70 to 75 quality nitrogen foam treatment with approximately 50 barrels of water and 20,000 pounds of 20/40 sand proppant.

Those treatments are pumped down 4-1/2 inch (10.50, K-55) casing at a pressure of 1,200 psi and a clean rate of 16 to 20 barrels per minute through 30 to 50 perforations. The sand concentration averages 4 pounds per gallon of foam. The breakdown pressure can reach 2,200 psi. No breakdown acid is used.

There are also a few wells in the vicinity of the Candidate Wells which have sufficient energy to displace the spent stimulation liquids, but the majority had not been stimulated. One recently drilled well has a reservoir pressure of only 125 psi, but a very strong flow rate. A decision was made to stimulate it with an 80 quality N_2 foam stimulation. The strong flow rate is believed to be adequate to reject the stimulation liquids.

XI. IS THE PROPOSED RESERVOIR LIKELY TO BENEFIT FROM THE CO_2/SAND TECHNOLOGY?

Because the CO_2/Sand stimulation utilizes CO_2 as the working fluid which is pumped as a liquid and will then vaporize at formation temperature and flow from the reservoir as a gas, no liquid remains behind and the gas can flow from the reservoir unimpeded through the artificially created and propped fractures.

A. OPERATOR

Ocean's working interest position in these wells ranged up to 100% and averaged approximately 62%. Additionally, they transport gas for other producing companies, Klabzaba Oil & Gas and John Brown resulting in a total throughput of 78 MMcf per day from 740 wells. The gas is delivered to Great Lakes Transmission via various pipelines operated by Montana Power, Trans Gas, and Trans Canada.

1. Interest in CO_2/sand technology?

   Ocean was interested in identifying a stimulation technique which could be used in this liquid sensitive, low pressure reservoir.

2. Adequate test opportunity?

   The proposed Candidates would enable an evaluation of the benefits of the liquid-free CO_2/sand stimulation process to be evaluated in an environment where conventional treatments, because the low reservoir pressure (225 psi) was insufficient to expel the spent stimulation liquids could not.

3. Presently active drilling program?

   Ocean had an active program and beyond that there were many existing wells which were unstimulated.

4. Is there a future for successful results? Is the operator likely to continue implementing this technology without DOE cost support?

   It was strongly indicated that Ocean would continue with the process if the production results were economically favorable.

5. Interest in DOE cost-supported participation?

   Ocean indicated an interest in participating in the cost-shared program.

6. Share production data for five years?

   They did not comply with the written agreement to provide the post stimulation production date for the agreed upon five year time period.

XII. <u>LETTER OF INTENT</u>

A Letter of Intent which:

A. Identified the proposed Candidate Wells, their location, the gas producing formations (Eagle Sandstones), and their sensitivity to damage from liquid-based stimulations

B. Recognized Ocean as the operator

C. Addressed the potential benefit of the liquid-free CO_2/Sand stimulations

D. Related that the DOE has a cost-shared demonstration project to introduce this unique technology to U.S. operators, and

E. That the DOE may, subject to their concurrence agree to bear one-half (1/2) of the costs of the stimulations, including the service company charges for product (CO_2, proppant), services, and mobilization.

F. Confirmed that Ocean was interested in participating in a cost-shared demonstration of the CO_2/Sand stimulation technology and was offering the Candidate Wells for consideration for cost-shared funding under this demonstration effort.

G. Confirms that Ocean agrees with and supports the Criteria for Success

H. Ocean agreed to make every effort to avoid "killing" these wells with water and that they would only kill a well in the event of an environmental or safety emergency. In the event of the need to introduce water into the well, Ocean agreed to immediately notify Petroleum Consulting Services (PCS) prior to the treatment.

I. Ocean agreed that to enable a meaningful comparison of the technologies to be made that these Candidate Wells will be turned in line shortly after stimulation and will be operated at wellhead pressures of 20 psi or less.

J. Ocean agreed to provide monthly production (gas, oil, and water) and pressure data for both the candidate and the control wells for a period of five years following the CO_2/Sand stimulations. (They failed to comply with this requirement) The monthly production information, including any recordings, shall be forwarded to PCS.

K. Ocean indicated an intention to enter into a 50/50 cost-shared participation of the stimulation expenses for these Candidate Wells, subject to DOE approvals.

L. Ocean agreed to bear the remaining expenses of these treatments and any remaining activities, i.e., those expenses normally associated with these treatments: cement bond log, perforating, bridge plug installation and removal (without introducing liquids if performed following the CO_2/Sand stimulations) dozers, service rigs, etc.

The Letter of Intent was executed by Ocean's Corporate Officer and is attached (Figure 7).

Figure 7 – p. 1 of 7

Letter of Intent – Demonstration CO_2/Sand Stimulation Project – May, 2002
p. 1 of 5

Operator:	Ocean Energy, Inc (Ocean)
Candidate Well Location:	Blaine County, Montana
Field:	Bear Paw - Tiger Ridge Unit
Target Formation:	Eagle Sandstone (Middle and Upper)
Candidate Wells:	Old Wells (three will be selected from the following list of presently producing wells):

Well	S - #
T30N-R18E	
S-B Ranch	02-05
Blackwood	06-09
Kane	05-08
Kane	05-05
Kane	04-12
S-B Ranch	02-11

Background:
The wells within the Bear Paw field in Blaine County, Montana produce from the pressure-depleted Eagle Sandstones, and are damaged by conventional liquid-based hydraulic fracturing stimulations. The damage results from the inability of the reduced reservoir pressure to expel the spent stimulation liquids following the treatment.

The invasion of the drilling mud into the Eagle Sands during the drilling of these wells and the inability to effectively stimulate them with liquid-based treatments provides an opportunity to evaluate the effectiveness of a liquid-free stimulation process. This technique utilizes CO_2 as the working fluid which, through the use of specialized equipment, can be pumped as a liquid and will then vaporize at the reservoir pressure and temperature and subsequently flow from the reservoir as a gas leaving a liquid-free proppant pack in the hydraulically created fracture.

This unique process has the potential to significantly improve the gas production rates both through the removal of the near well bore formation damage resulting from the invasion of drilling mud, and also by hydraulically fracturing the formations and placing a liquid-free sand pack within it.

A demonstration project to evaluate the benefits of the liquid CO_2/Sand process in three (3) of the six (6) proposed Candidate Wells is herein described.

Objective:
To evaluate the potential benefit of a liquid-free CO_2/Sand hydraulic stimulation technology in reservoirs from which the natural gas production is impaired by the liquids employed in conventional stimulation treatments.

Figure 7 – p. 2 of 7

Methodology:
The evaluation will be conducted within a controlled setting to enable an objective assessment of the production responses resulting from these stimulations to be made. The Candidate Wells have been completed in the target formation and have been selected on the basis of their upside potential for production rate improvement, a commercial volume of remaining reserves, and mechanical suitability for this demonstration (number of perforations & tubing diameter). The proposed Candidates have sufficient background production history to provide the basis for comparing the post-stimulation production rates following the CO_2/Sand stimulations.

Statement:
Whereas, Ocean Energy (Ocean) is the operator of certain wells situated in Blaine Co, Montana within the Tiger Ridge Unit of the Bear Paw Field.

Whereas, Certain formations within this area including the Eagle Sands typically contain natural gas which is drilled and exploited by Ocean.

Whereas, The exploitation of the natural gas from the Eagle Sands is known to benefit from hydraulic stimulation practices to increase the gas production rate and thereby enhance the economic benefit.

Whereas, Conventional hydraulic stimulation practices utilize water-based treatments, and because the reservoir pressure within certain areas of this field has diminished to the point where it is insufficient to eject the spent stimulation liquids from the reservoir.

Whereas, There is a unique "liquid-free" hydraulic stimulation technology which utilizes liquid Carbon Dioxide (CO_2) as the working fluid, and which because of its characteristics enables a stimulation treatment to be pumped as a liquid to both create hydraulic fractures and also to transport proppant. The CO_2 then subsequently changes phase from a liquid to a gas at reservoir conditions and the formation is then void of any liquids or other chemicals which were used in the stimulation.

Note: This CO_2/Sand stimulation process requires a unique, specialized blender to mix the CO_2 and proppant under pressure.

Whereas, The cost of these treatments is more expensive than conventional treatments primarily because of the specialized equipment required and also the cost of the CO_2.

Whereas, The U.S. Department Of Energy (DOE) has a cost-shared demonstration project to introduce this unique technology to U.S. operators. The intention of this program is to enable the operator to evaluate the benefits of this technology on its wells, providing that certain reservoir conditions are present, and that the reporting requirements are satisfactory to both parties. If these conditions exist then, the DOE may, subject to their concurrence agree to bear one-half (1/2) of the costs of the stimulations, including the service company charges for product (CO_2, proppant), services, and mobilization.

Whereas, The DOE requires that in order to provide a representative demonstration that a minimum of three (3) of the Candidate Wells be stimulated.
Whereas, The demonstration of the CO_2/Sand technology is provided through DOE's prime contractor, Petroleum Consulting Services, LLC (PCS).

Figure 7 – p. 3 of 7

Letter of Intent – Demonstration CO_2/Sand Stimulation Project – May. 2002
p. 3 of 5

Whereas, Ocean is interested in participating in the cost-shared demonstration of the CO_2/Sand stimulation technology, and is offering the Candidate Wells as described above for consideration in the cost-shared funding under this demonstration effort.

Therefore, because Ocean Energy (Ocean) is the operator of the Candidate Wells, and is interested in stimulating these wells with the CO_2/Sand stimulation process does hereby agree to the terms of this agreement, and is hereby requesting DOE support in demonstrating the liquid-free CO_2/Sand stimulation process in these Candidate Wells.

The completion, remaining production, and some reservoir properties of the Candidate Wells have been obtained and are summarized as:

Well	S - #	Perfs Upr Eagle	Perfs Mid Eagle	H_2O Lvl	Rem (MMcf)	Skin	Prod (Mcf/d)	TIL	Pi (Psi)	P* (Psi)
T30N-R18E										
S-B Ranch	02-05	1134–1197w/10	1220–1261w/ 8	TBD	484,345	TBD	35	??/01	TBD	TBD
Blackwood	06-09	1144–1162w/35	1156-1230w/ 45	TBD	986.5	+2.83	220	10/80	222	114
Kane	05-08	1362-1408w/48	1436-1474w/ 32	TBD	1,306.5	+2.00	100	11/82	175	95
Kane	05-05	1110–1136w/42	1170-1220w/ 74	TBD	249.3	+12.9	60	10/91	297	83.5
Kane	04-12	1238-1284w/71	1316–1375w/112	TBD	1,131	TBD	100	07/85	204	TBD
S-B Ranch	02-11	1068–1102w/16	1164–1204w/ 8	TBD	4,636.40	-1.82	180	12/72	225	TBD

Criteria for Success
The Criteria for success has been developed for each Candidate Well and is based on the following assumptions:

1.	Capital cost for the CO_2/Sand stimulation treatment:	$86M
2.	Market price:	$2.50/dth - fixed
3.	Calorific value:	1000 BTU/CF
4.	Discount rate:	25%
5.	Production decline rate:	Variable and driven by the production projections supplied by Ocean.

And, which have been used to determine the following total uninterrupted and unencumbered minimum annual production volumes as indicated below, necessary for an economic success.

T30N-R18E		Yr 1	Yr 2	Yr 3	Yr 4	Yr 5
Well	# - S	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)
From		06/01/02	06/01/03	06/01/04	06/01/05	06/01/06
Through		05/31/03	05/31/04	05/31/05	05/31/06	05/31/07
S-B Ranch	02-05	25,199	21,421	18,208	15,474	13,153
Blackwood	06-09	90,383	85,593	81,057	76,761	72,692
Kane	05-08	47,626	42,501	37,927	33,845	30,203
Kane	05-05	33,063	24,485	18,134	13,428	9,944
Kane	04-12	51,348	46,873	42,789	39,061	35,658
S-B Ranch	02-11	78,306	71,865	65,954	60,530	55,551

Figure 7 – p. 4 of 7

Ocean hereby agrees that these production projections will serve as the basis for establishing the success criteria, and if the actual production volumes from these Candidate Wells exceed these tabulated annual production volumes, subject to adjustments for any non-producing intervals, then Ocean agrees that the CO_2/Sand stimulation process will have resulted in an economic benefit.

Stimulation Treatment:
The design of the stimulation treatments is to consist of approximately 120 tons of liquid carbon dioxide (CO_2) and up to 47,500 pounds of TBD size sand proppant pumped at injection rates of approximately 50 to 60 barrels per minute, and is to consist of a single-stage treatment in each of the three Candidate Wells.

Requirements
Ocean further agrees to comply with the following requirements

1. Because the liquid-free CO_2/proppant process provides a completely dry stimulation it is imperative that liquids not be introduced into the well bore following these treatments.

   Ocean agrees to make every effort to avoid "killing" these wells with water or other liquid substance, and agrees that any effort to kill a Candidate Well will only take place in the event of an environmental or safety emergency. In the event of the need to introduce water or other liquids into any well in which DOE participates, then Ocean will immediately notify PCS prior to the introduction of liquids into a Candidate Well.

2. Ocean agrees that to enable a meaningful comparison of the technologies to be made that these candidate wells will be turned in line shortly after stimulation and will be operated at wellhead pressures of 20 psi or less.

3. Ocean agrees to provide monthly production (gas, oil, and water) and pressure data for both the candidate and the control wells for a period of five (5) years following the CO_2/Sand stimulations. The monthly production information, including any recordings, shall be forwarded directly to PCS.

4. If following the treatments any proppant is found in the casing above the lowermost perforation, it will be removed from the well bore at Ocean's expense. No liquids will be circulated for the clean-out unless written approval is obtained from the DOE.

5. The production will be adjusted for any non-producing periods, should they occur

6. The CO_2/Sand stimulation will be considered an economic success if the above tabulated annual production volumes are attained.

7. If there should be any additional discounts associated with these activities, then Ocean agrees to promptly forward one-half to PCS for return to the DOE.

Figure 7 – p. 5 of 7

Letter of Intent – Demonstration CO_2/Sand Stimulation Project – May. 2002
p. 5 of 5

The DOE, subject to their approval of the submitted information, which includes:

1.	Letter of Intent	This document
2.	A map of the candidate wells and nearby offsetting wells	Candidate wells
3.	Electric logs	Candidate wells
4.	Cumulative production data	Candidate wells
5.	Monthly pipeline pressure data	Candidate wells
6.	Stimulation records tabular and strip charts	Candidate wells
7.	Well completion reports	Candidate wells
8.	Description of the field activity	Candidate Wells
9.	Schedule for treating the candidate wells TBD, 2002	TBD
10.	Liability Release (PCS, LLC)	Separate Document

Ocean hereby indicates an intention to enter into a 50/50 cost-shared participation of the stimulation expenses for these candidate wells, subject to DOE approvals.

Ocean agrees to bear the remaining expenses of these treatments and any remaining activities, i.e., those expenses normally associated with these treatments: cement bond log, perforating, bridge plug installation and removal (without introducing liquids if performed following the CO_2/Sand stimulations) dozers, service rigs, etc.

If these conditions are satisfactory, please acknowledge by signing below, and returning this document to:

Petroleum Consulting Services, LLC
P. O. Box 35833
Canton, Ohio 44735
(330) 499-3823 (330) 499-2280 (fax)

Date: 5/23/02

Signed: [signature]
Company Officer - Ocean Energy, Inc.

Title: V.P. EXPLORATION NAO

Witness:____________________

Figure 7 – p. 6 of 7

AMMENDMENT TO LETTER OF INTENT (LOI) DATED MAY 23, 2002
DATE: July 15, 2002
p. 1 of 2

As an outcome of discussions held on July 9, 2002 between the;

Operator: Ocean Energy, Inc (Ocean),
Contractor: PCS, and
The U.S. Department of Energy (DOE);

regarding the identification of Candidate Wells located in Blaine County, Montana (T30N-R18E), and their stimulation with the liquid-free CO_2/Sand stimulation process under the terms of the original LOI. - which addresses the provisions for a cost-shared demonstration of this technology, the following modifications were made:

1. The number of Candidate Wells to be stimulated with and has been increased from three to four.

2. The Candidate Wells have been specifically identified as:

Well	S - #
T30N-R18E	
S-B Ranch	02-05
Blackwood	06-09
Kane	05-08
Kane	05-05

3. The S-B Ranch 02-05 has a limited number of perforations, 18 and is completed in both the Upper and Middle Eagle Sand members. Based on the electric log response it is not expected to produce water.

   It was agreed that both the Upper and Middle Eagle Sand intervals would be stimulated with a single-stage CO_2/Sand stimulation

4. The other three Candidate Wells, Blackwood 06-09, Kane 05-08, and Kane 05-05 will be stimulated in the Upper Eagle Sand member only.

   The Upper Eagle will be isolated through the installation of a solid, impermeable plug inside the production casing, between the Upper and Middle Eagle formations which will prevent the stimulation treatment from passing it.

5. The steady-state production rates need to be established prior to the stimulation.
   The plan is to set temporary plugs in these three Candidate Wells within a few days and to begin the production monitoring.

6. The plugs will remain in place for a period of time sufficient to obtain a post-stimulation steady state production rate.

Figure 7 – p. 7 of 7

AMMENDMENT TO LETTER OF INTENT (LOI) DATED MAY 23, 2002
DATE: July 15, 2002
p. 2 of 2

7. The treatments will utilize radioactive tracers to enable the location of the hydraulically created fracture(s) to be specifically identified providing:
   a. That the service company can demonstrate their ability to inject the radioactive isotopes into liquid CO_2 at a pressure of 300 psi and at a temperature of 0 degrees Fahrenheit prior to the treatments.
   b. The hazards associated with immediate flow back of sand in the well bore following a screen out can be assured as a safe procedure

8. The hurdle production rates were calculated previously, and are addressed in the original LOI.

If these modifications to the original LOI are satisfactory, please acknowledge by signing below, and returning this document to:

Petroleum Consulting Services, LLC
P. O. Box 35833
Canton, Ohio 44735
(330) 499-3823 (330) 499-2280 (fax)

Date: July 19, 2002

Signed: Gregory E Evans
Company Officer - Ocean Energy, Inc.

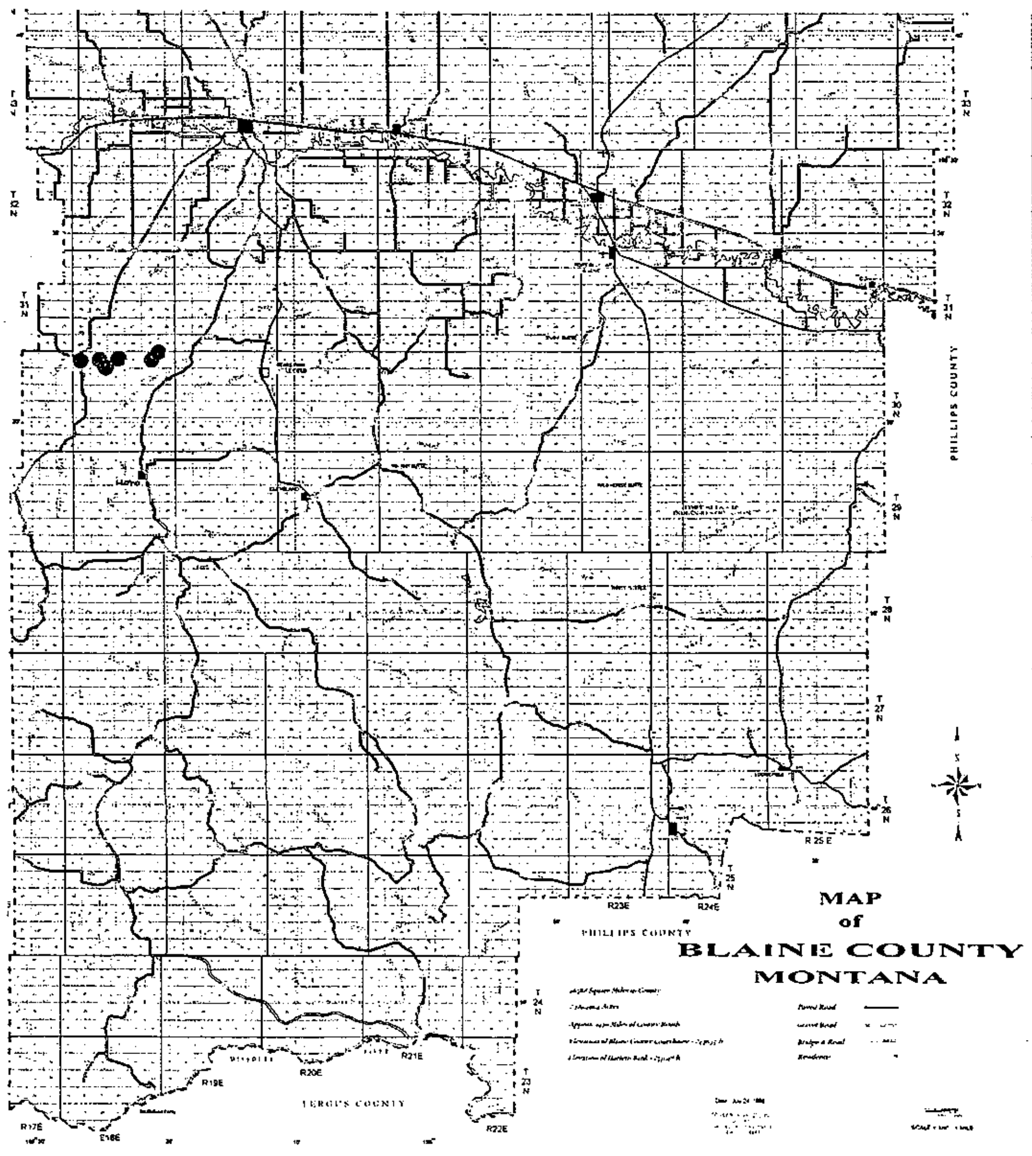
Title: VP Exploration North America

Witness: Ken Seigel 7/19/2002

XIII. TEST AREA

Discussions with Ocean were directed towards the identification of an area in which the reservoir pressure of the Eagle Sandstone was depleted, where there was a sufficient data base of background production information, and which would hold an appreciable basis for future activity. The result being that a test area was identified in T30N, R18E. The accompanying map (Figure 8) indicates the test area and the Candidate Wells.

Figure 8



A. Control Wells

There were no Control Wells included in this effort because the Candidate Wells were actively producing wells which enabled both the pre- and post-stimulation production rates to be measured and compared.

This approach is unique to this effort because in the past the producing wells had been previously stimulated with liquid-based treatments and the reservoir was considered to be damaged by these stimulation liquids. Consequently, the CO_2/Sand stimulations had to be performed in new, unstimulated wells and, the existing previously stimulated wells served as the Control Wells to which the production responses were compared.

This approach in measuring the pre- and post-stimulation response from wells which have never been stimulated is superior to that which utilized the Control Wells because the well specific variables of porosity, thickness, etc. are eliminated.

B. Candidate Wells – 6 > 4 Wells

There were six originally proposed Candidate Wells from which four were selected. They are located within Township 30N-Range 18E (Figures 9 and 10). The wells are listed in the order considered by Ocean to provide the greatest opportunity to demonstrate and evaluate the effectiveness of the CO_2/Sand stimulation technology, that is, the S-B Ranch 02-05 is considered to be the most desirable for stimulation. (Ultimately Blackwood 06-09 had the largest incremental improvement of 54.1 MMcf following 22 producing months following the stimulation).

Well						Stim Type	Rem	Skin	Prod	Pi
T30N-R18E	S - #	Upr Eagle Perfs	Mid Eagle Perfs	Lwr Eagle Perfs	PB Req'd	(Sxs, Bbls)	(MMcf)		(Mcf/d)	(Psi)
S-B Ranch	02-05	1120-1202 1134–1197w/12	1222-1260 1220–1261w/ 8	1283-1290 None	No	None	484.345	TBD	35	170
Kane	05-08	1359-1334 1362-1380w/22	1436-1502 1388-1408w/ 26	1515-1538 None	Yes@1420	None	359.000	+2.00	100	175
Kane	05-05	1094-1142 1110–1136w/42	1168-1233 1170-1220w/ 74	1283-1290 None	Yes@1150	None	96.700	+12.9	60	297
Blackwood	06-09	1142-1188 1144–1147w/20	1241-1288 1156-1162w/ 18	1302-1328 None	No	None	986.500	+2.83	220	222
Kane	04-12	1238-1301 1238-1284w/71	1316-1383 1316–1375w/112	1395-1422 None	Yes@1294	None	460.568	+6.74	100	204
S-B Ranch	02-11	1052-1128 1068–1102w/16	1157-1238 1164–1204w/ 8	1250-1252 None	No	None	853.946	-1.82	180	225

Figure 9

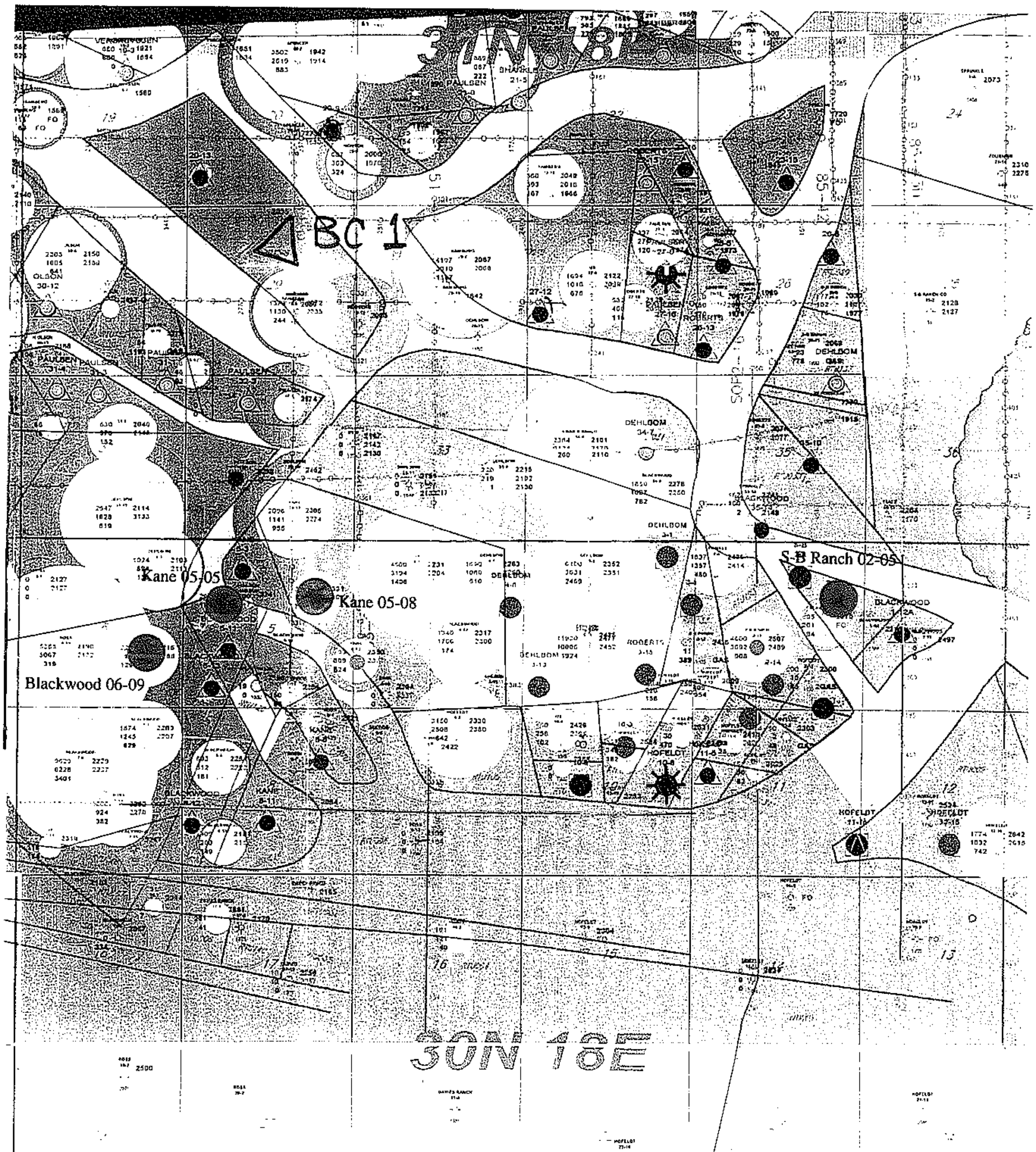
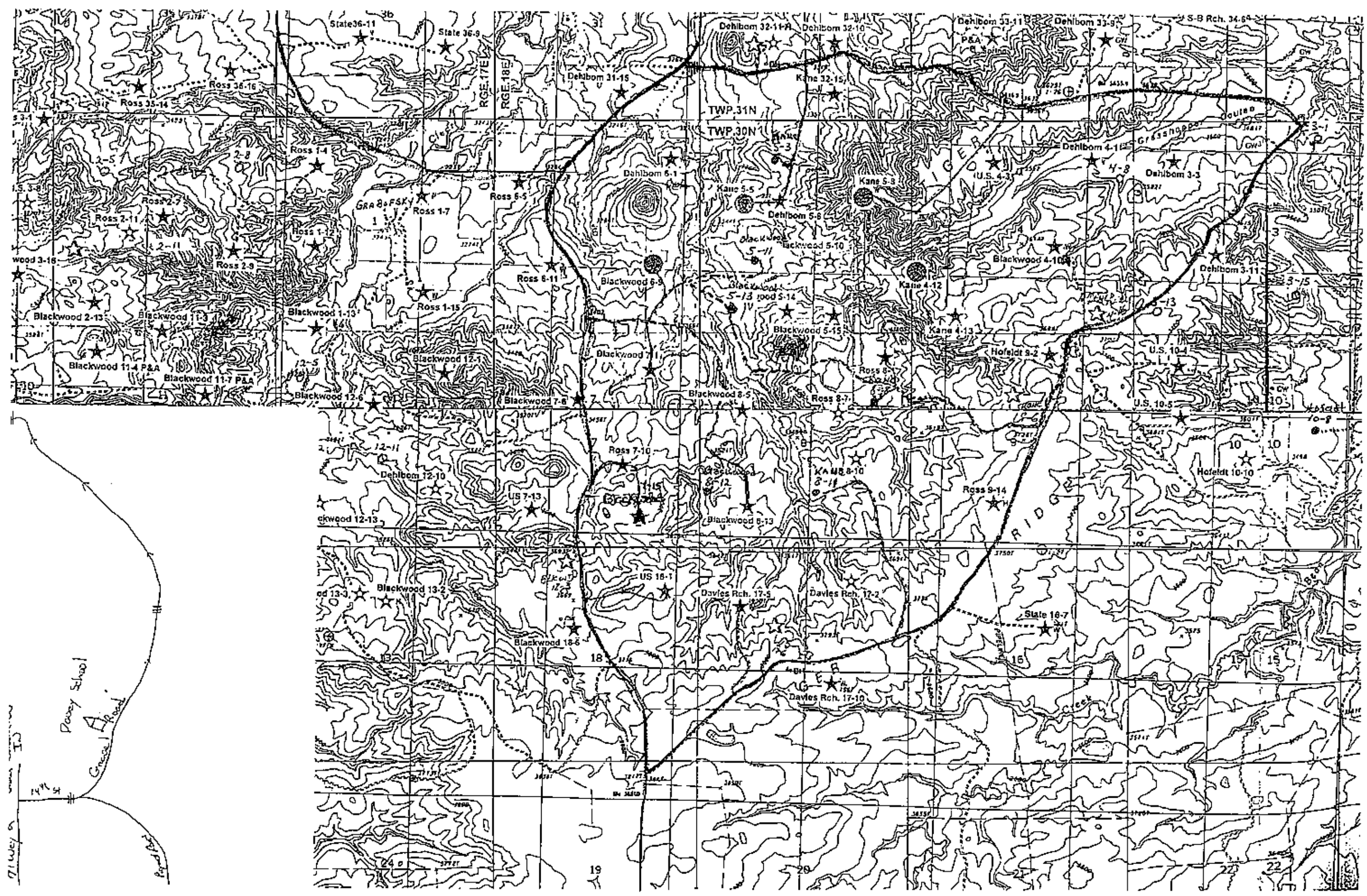

31N 18E
BC 1
Kane 05-05
Kane 05-08
Blackwood 06-09
S-B Ranch 02-05
30N 18E

Figure 10



1. Electric Logs

   a. The electric logs on two of the Candidate Wells are attached (Figures 11 and 12).

Figure 11 S-B Ranch 02-05

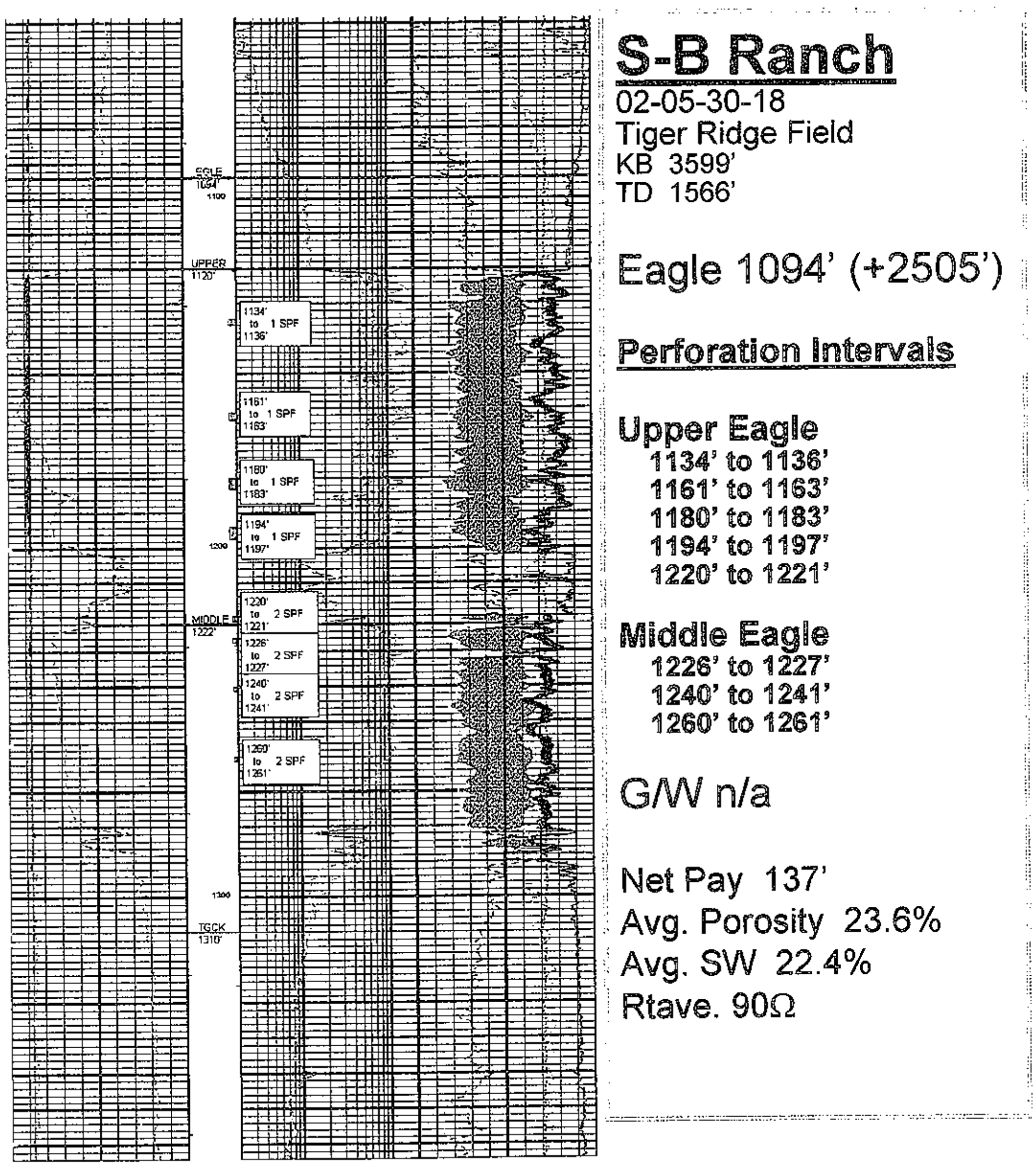
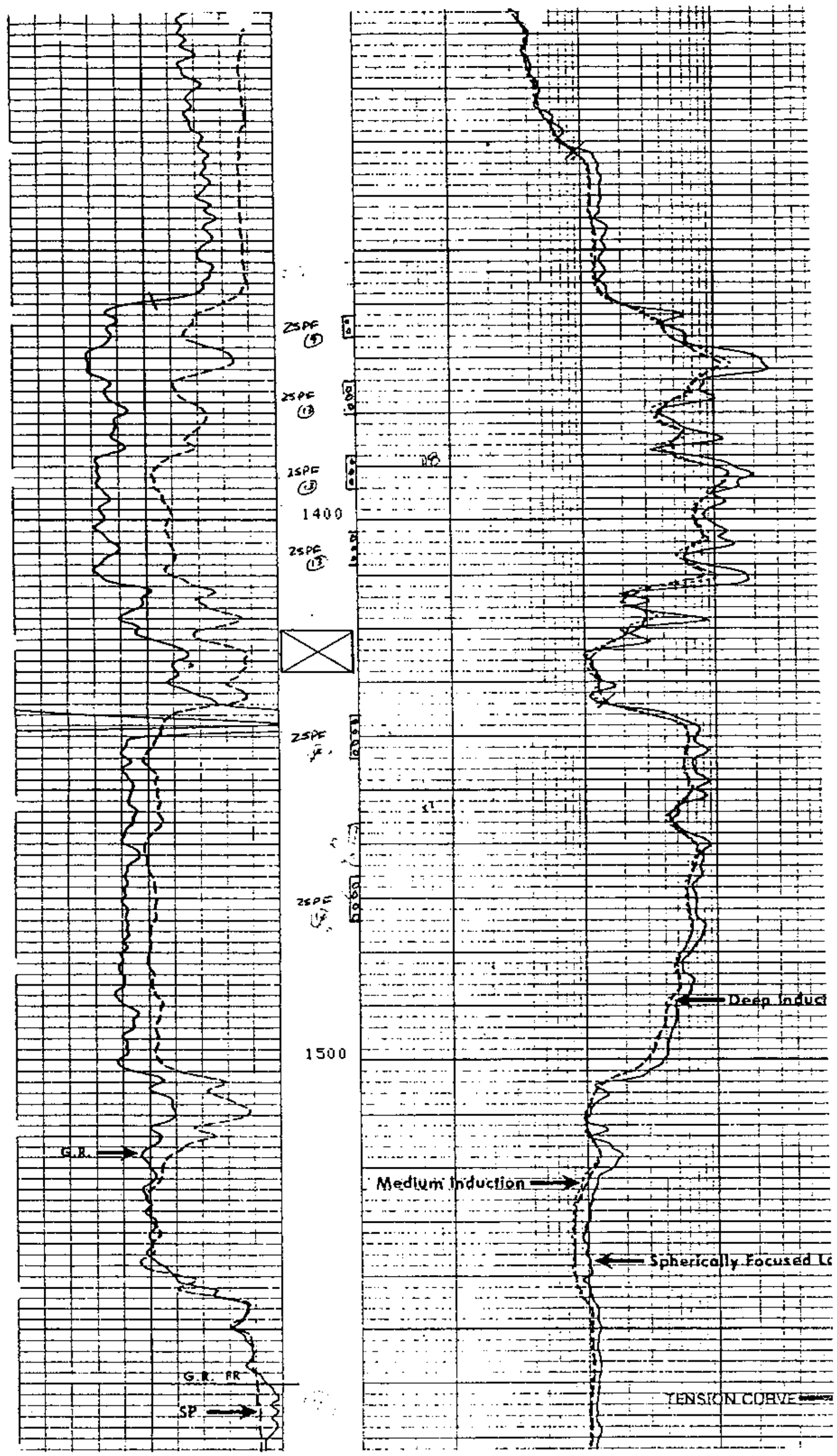


Figure 12 Kane 05-08



2. Completion

The completion technique was to set and cement casing, generally 4-1/2 in, through the Eagle Sands, run electric logs to determine the gas/water contact, and perforate above it. Generally, the Upper Eagle and upper section of the Middle Eagle were perforated. No stimulations were generally performed because the reservoir pressure (225 psi) was insufficient to expel the spent stimulation liquids

3. Perforation Strategy

The design criteria was to limit the number of perforations to a maximum of 40. Because of the large number of perforations in three of the Candidates, and the associated concern regarding an insufficient transport velocity, the design included temporarily plugging-off the lower perforations during the stimulation.

Well							Total Perfs
T30N-R18E	S - #	Upr Eagle Perfs	Mid Eagle Perfs	Lwr Eagle Perfs	PB Req'd	Add'l Perfs	During Stim
S-B Ranch	02-05	1120-1202 1134–1197w/12	1222-1260 1220–1261w/ 8	1283-1290 None	No	20	40
Kane	05-08	1359-1334 1362-1380w/48	1436-1502 1388-1408w/ 34	1515-1538 None	Yes@1420	-34	48
Kane	05-05	1094-1142 1110–1136w/42	1168-1233 1170-1220w/ 74	1283-1290 None	Yes@1150	-74	42
Blackwood	06-09	1142-1188 1144–1147w/20	1241-1288 1156-1162w/ 18	1302-1328 None	No	0	38
Kane	04-12	1238-1301 1238-1284w/71	1316-1383 1316–1375w/112	1395-1422 None	Yes@1294	-112	71
S-B Ranch	02-11	1052-1128 1068–1102w/16	1157-1238 1164–1204w/ 8	1250-1252 None	No	16	40

4. Production Review and Projections

All six of the proposed Candidate Wells produce from both the Upper and Middle Eagle Sand members. None were perforated in the Lower Eagle. Three of the Candidate Wells contained a large number of perforations which were considered to be too many and for the CO_2/Sand process.

This was because the proppant transport rate into the individual perforations will insufficient to transport the proppant and will increase the likelihood of a screen out.

The wells were rank ordered by Ocean in their recommended sequence which was believed to provide the most benefit. This rank ordering results in the plugging of the Lower Eagle Sand in the wells which are ranked 3, 4, and 5, which almost dictates that at least one of the three Candidates will require plugging of the Middle Eagle and treating the Upper sand member only.

Well T30N-R18E	S - #	Upr Eagle Perfs	Mid Eagle Perfs	Lwr Eagle Perfs	PB Req'd	Prod (Mcf/d)
S-B Ranch	02-05	1120-1202 1134–1197w/12	1222-1260 1220–1261w/ 8	1283-1290 None	No	35
Blackwood	06-09	1142-1188 1144–1147w/20	1241-1288 1156-1162w/ 18	1302-1328 None	Yes	220
Kane	05-08	1359-1334 1362-1380w/22	1436-1502 1388-1408w/ 26	1515-1538 None	Yes@1420	100
Kane	05-05	1094-1142 1110–1136w/42	1168-1233 1170-1220w/ 74	1283-1290 None	Yes@1150	60
Kane	04-12	1238-1301 1238-1284w/71	1316-1383 1316–1375w/112	1395-1422 None	Yes@1294	100
S-B Ranch	02-11	1052-1128 1068–1102w/16	1157-1238 1164–1204w/ 8	1250-1252 None	No	180

In order to properly measure the production response associated with the CO_2/Sand treatment, a producing period sufficient to eliminate the production from the un stimulated interval (Middle Eagle) was agreed to.

Ocean installed the temporary plugs immediately before the stimulation and then removed it after 22 months following the CO_2/Sand stimulation. This procedure allowed for the stimulation of only the Upper Eagle while comparing the post-stimulation production from both the Upper and Middle Sands.

The production histories for the six Candidate Wells were plotted and accompanied the submittal package to the DOE. The production rates for each well was identified, and used as an input to determine the minimum annual post-stimulation production necessary to achieve an economic success. The economic success calculations are attached and addressed in the CRITERIA FOR SUCCESS section.

XIV. CO_2/SAND STIMULATION TREATMENTS

A. Design

In the initial proposal various stimulation designs were prepared by Canadian Fracmaster and presented to Ocean. The result being that the design which included the largest proppant volume was selected.

During the two year intervening period, Canadian Fracmaster had been acquired by another service company, and bids for the CO_2/Sand stimulations were obtained from another Canadian based service company, TriCan Well Service, Ltd.

The proposed design included 44,100 pounds of 20/40 sand proppant and 685 barrels of liquid CO_2 (132 tons) pumped at 47 barrels per minute – The pumped volume is 513 barrels (99 tons) . The maximum sand concentration is 5 pounds per gallon, and the projected wellhead pressure is 1,531 psi (10,560 kPa). A copy of the proposal including the sand schedule is attached (Figure 13).

Figure 13 – p. 1 of 7

CO2/SAND STIMULATION - OCEAN ENERGY - BLAINE CO, MT *06/01/02*

INPUTS				DELIVERY DISTANCES(Km)			COST($CAN)	COST($US)
PRODUCT	SAND	441	SX	300	PER WELL		$95,811	$62,422
	CO_2	160	TONS	300				
	N_2/CO_2	1.03	MCF/TON			OPERATOR		$31,211
HORSEPOWER		1770	HHP			DOE		$31,211
PUMP RATE		47	BPM					$62,422
DISCOUNT		40	%					

	N_2	164.8	MCF	300
CONVERSION FACTORS:	KW/HP	1.3410	sm^3/TON	1.2120
	m^3/BBL	6.2905	tonne/TON	1.1025
	Kg/LB	2.2050	Km/MI	1.6090
	sm^3/SCF	35.3100	$US/$CAN	0.6515

DESCRIPTION	METRIC UNIT	METRIC QUANT	UNIT COST*($CAN)	COST($CAN)	COST($US)	US UNIT	US QUANT	UNIT COST*($US)	
STAGE #1									
PUMPING	KW	1319.91	12.30	16,235	10,577	HHP	1770	5.98	$US/HHP
BLENDER(SET UP)	UNIT	1	2190.00	2,190	1,427	UNIT	1	1426.80	$US/UNIT
BLENDER(PUMPING)	m^3/min	7.5	210.00	1,569	1,022	BPM	47	21.75	$US/BPM
20/40 API SPEC SAND	tonne	20	380.00	7,600	4,951	SK	441	11.23	$US/SK
SAND DELIVERY	tonne/Km	6000	0.95	5,700	3,714	TON/MI	4,111	0.90	$US/TON/MI
DENSIOMETER									
CONNECTION TRUCK	UNIT	1	1510.00	1,510	984	UNIT	1	983.78	$US/UNIT
VAN	UNIT	1	3860.00	3,860	2,515	UNIT	1	2514.82	$US/UNIT
N_2 PUMPING UNITS	UNITS	2	2250.00	4,500	2,932	UNITS	2	1465.89	
N_2	sm^3	4667	1.35	6,301	4,105	MCF	165	24.91	
N_2 DELIVERY									
CO_2	sm^3	132	635.00	83,825	54,613	TONS	160	341.33	$US/TON
PORTABLES	UNITS	2	2440.00	4,880	3,179	UNITS	2	1589.68	$US/UNIT
TRANSPORT (SET UP)	UNITS	2	620.00	1,240	808	UNITS	2	403.94	$US/UNIT
CO_2 DELIVERY	m^3-Km	39602.6	0.39	15,445	10,063	TON/MI	77,232	0.13	$US/TON/MI
			TOTAL	154,855	100,889				
WELLS		3	TOTAL	464,565	302,668				
MILEAGE-FRAC UNIT (8)	UNIT/Km	2400	4.83	11,592	7,552	UNIT/MI	1.96		
MILEAGE-FRAC UNIT (2)	UNIT/Km	600	4.83	2,898	1,888	UNIT/MI	1.96		
			TOTAL	14,490	9,440				
			TOTAL- 3 WELLS	$479,055	$312,109				
			DISCOUNT	$191,622	$124,843				
			TOTAL- 3 WELLS	$287,433	$187,265				
			PER WELL	$95,811	$62,422				
				OPERATOR	$31,211				
				DOE	$31,211				
					$62,422				

Figure 13 – p. 2 of 7

----- Original Message -----
From: Browne, Dave
To: Raymond L. Mazza
Sent: Wednesday, February 20, 2002 6:03 PM
Subject: RE: Quote for Liquid CO2 Fracs Near Havre, MT

Ray,

1.We can frac at Havre for US$ 56,000 per frac. This is based on the the information you supplied Mike Tulissi regarding horsepower, spliting the mileage between 3 fracs, assuming there is only one day between each frac and we frac in April. I'll send you a program soon.

2. We are interested bidding on the Kentucky fracs for April or May. It would be best if we could do Havre and Kentucky in the same border crossing.

3. We will also like to bid on your other projects.

Dave Browne

-----Original Message-----
From: Raymond L. Mazza [mailto:o.g@worldnet.att.net]
Sent: February 20, 2002 9:50 AM
To: David J Browne
Cc: Gary Covatch; Al Yost
Subject: Quote for Liquid CO2 Fracs Near Havre, MT

Dave,

During your absence last week, I spoke with Michael Tulissi regarding

1. An updated cost estimate for your previous proposal (10/17) for stimulating three wells near Havre, Mt with single-stage treatments during your slack time, perhaps in April. The design would be for 20 Tonnes of 30/50 proppant, 120 short tons of CO2, and 2000 hydraulic horsepower.

2. Interest in performing liquid CO2 fracs in eastern Kentucky, near Pikeville in April. The design would be for 20 Tonnes of 30/50 proppant, 120 short tons of CO2, and 4000 hydraulic horsepower.

3. Exploring your interests in providing liquid CO2 stimulation treatments in the western U.S. in south west Wyoming and northern New Mexico.

Please let me know as soon as you can about the quote for Havre as the operator is awaiting my call back.

Welcome back,

Regards,

Ray Mazza (330) 499-3823

2/22/2002

Figure 13 – p. 3 of 7

TRICAN WELL SERVICE LTD.

STIMULATION PROPOSAL

Liquid CO2 Frac

20.0 tonne Sand (20/40)

Belly River - Eagle (Gas)

Ocean Energy - Hill County

Havre Montana

Version 3 Option 1

Inject Down Casing

Approved: February 20 2002

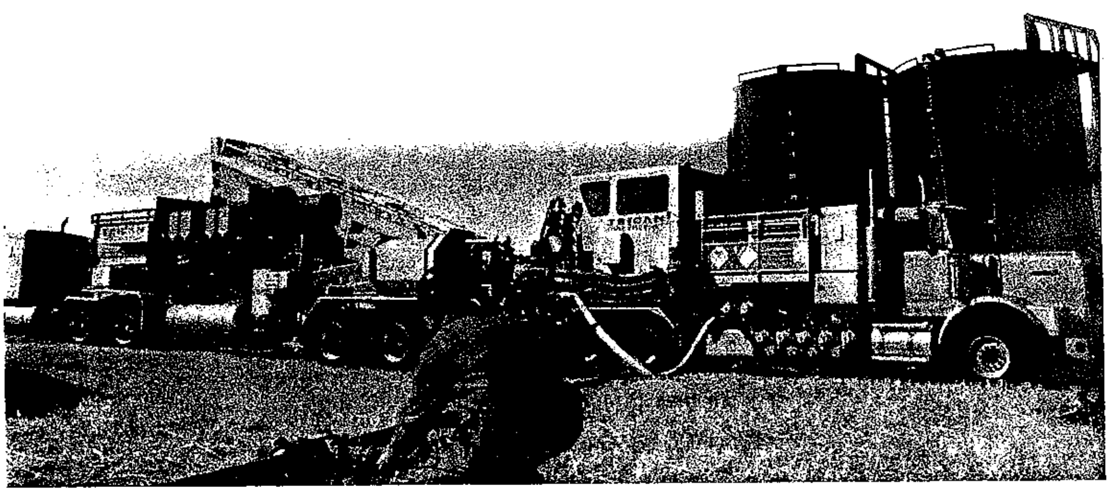
PETROLEUM CONSULTING SERVICES

Box 35833
Canton, Ohio
44735

Prepared For: Raymond Mazza

For Service Call: Red Deer (403) 346-4667

Sales Rep: Chuck Vozniak (403) 215 1982 **Designed By:** David Browne (403) 215 5890



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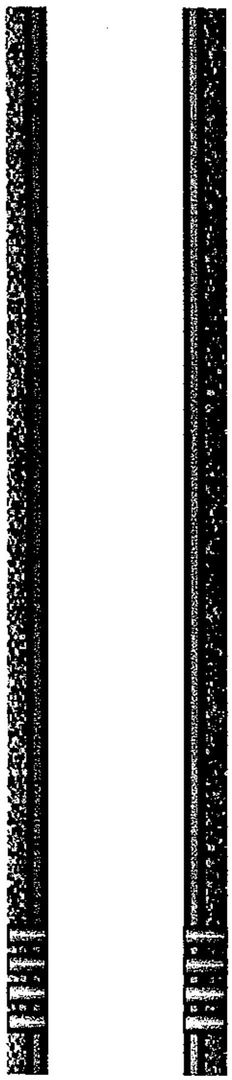
TRICAN
Ocean Energy - Hill County Havre Montana
Liquid CO2 Frac
Option 1 Version 3

Completions



Wellhead: Wellhead Saver (Casing)
Pumping Configuration: Casing

Casing: 114.3mm, 14.14kg/m, J-55
0.0 - 480.0 m (TMD)
Burst: 30 MPa
Collapse: 23 MPa

Hole Volume: 3.87 m^3

Perforations: 457.0 - 480.0 m (TMD)

Formation: Belly River - Eagle (Gas)
Frac Gradient: 20.0 kPa/m
BHST: 14 °C

Calculations

$P_{fracture}$ = $Gradient_{fracture}$ (20.0 kPa/m) x $Depth_{vertical}$ (480.0 m) = **9600 kPa**
$P_{friction}$ = $Gradient_{friction}$ (12.0 kPa/m) x $Depth_{measured}$ (480.0 m) = **5760 kPa**
$P_{hydrostatic}$ = $Gradient_{hydrostatic}$ (10.0 kPa/m) x $Depth_{vertical}$ (480.0 m) = **4800 kPa**
$P_{injection}$ = $P_{fracture}$ (9600 kPa) + $P_{friction}$ (5760 kPa) - $P_{hydrostatic}$ (4800 kPa) = **10560 kPa**
$Power_{CO_2}$ = $P_{injection}$ (10560 kPa) x $Rate_{CO_2}$ (7.5 m^3/min) / 60 = **1320 kW**

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Ocean Energy - Hill County Havre Montana
Liquid CO2 Frac
Option 1 Version 3

Procedures

Equipment: 2 CO2 Storage Tanks
1 CO2 Transport
1320 kW Frac CO2 Pumping
1 Frac Van
1 Iron Truck
1 Liquid CO2 Blender
2 N2 Pumping Units

Objective: To perform a CO2 Frac treatment on the Eagle (Belly River) formation.

Key Notes: Be prepared to flow well back immediately following treatment.

Safety: Spot tanks and equipment as per recommended equipment spacing. Conduct pre-treatment safety meeting with all personnel on location. Review all fire, chemical, and high pressure hazards.

Rig Up: Rig up to fracture well down Casing, through a Wellhead Saver (Casing).

Pressure: Pressure Test: 30 MPa
Maximum Pressure: 24 MPa

Rate: Anticipated downhole rate is 7.50 m³/min, at 10,560 kPa.

Spearhead: 1.00 m³ of Spearhead Acid.

Pad: 20.00 m³ of CO2.

Proppant: 20.00 tonne of Sand (20/40), placed with 58.53 m³ of CO2.

Flush: 3.07 m³ of CO2. This corresponds to an underflush volume of 0.80 m³, and must be recalculated on location.

Shut In: Shut in well, and rig out Trican equipment. Customer will supply all flowback equipment. When flowing well back, follow Alberta Recommended Practices, OHS, & AEUB recommendations.

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Ocean Energy - Hill County Havre Montana
Liquid CO2 Frac
Option 1 Version 3

Treatment Schedules

Liquid CO_2 Blender Treatment Schedule1

Stage	Blender Slurry			Blender Clean				Blender Proppant				Fluid And Proppant
	Rate (m^3/ min)	Volume (m^3)		Rate (m^3/ min)		Volume (m^3)		Concentration (kg / m^3)		Amount (tonne)		
	Start of Stage	Per Stage	Cum. At End Of Stage	Start of Stage	End of Stage	Per Stage	Cum. At End Of Stage	Start of Stage	End of Stage	Per Stage	Cum. At End Of Stage	
1 Spearhead	1.00	1.0	0.0	1.00	1.00	1.0	0.0					Spearhead Acid
2 Pad	7.50	20.0	20.0	7.50	7.50	20.0	20.0					CO2
3 Proppant	7.50	5.1	25.1	7.36	7.23	5.0	25.0	50	100	0.4	0.4	CO2 Sand (20/40)
4 Proppant	7.50	10.6	35.7	7.23	6.97	10.0	35.0	100	200	1.5	1.9	CO2 Sand (20/40)
5 Proppant	7.50	10.9	46.7	6.97	6.74	10.0	45.0	200	300	2.5	4.4	CO2 Sand (20/40)
6 Proppant	7.50	11.3	58.0	6.74	6.52	10.0	55.0	300	400	3.5	7.9	CO2 Sand (20/40)
7 Proppant	7.50	11.7	69.7	6.52	6.31	10.0	65.0	400	500	4.5	12.4	CO2 Sand (20/40)
8 Proppant	7.50	12.1	81.8	6.31	6.12	10.0	75.0	500	600	5.5	17.9	CO2 Sand (20/40)
9 Proppant	7.50	4.3	86.1	6.12	6.12	3.5	78.5	600	600	2.1	20.0	CO2 Sand (20/40)
10 Flush	7.50	3.1	89.2	7.50	7.50	3.1	81.6					CO2

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Ocean Energy - Hill County Havre Montana
Liquid CO2 Frac
Option 1 Version 3

Fluid And Mixing Requirements

HCl (15%) Volume From Program: 1.0 m³
Total HCl (15%) Volume: 1.0 m³

CO2 (Liquid) Volume From Program: 81.6 m³
Cool-down and Losses: 27.4 m³
Total CO2 (Liquid) Volume: 109.0 m³ Requires: 1 CO2 Transport
2 CO2 Storage Tanks

N2 Volume From Program: 4000 sm³
Cool-down and Losses: 600 sm³
Total N2 Volume: 4600 sm³ Requires: 2 N2 Pumping Units

1 m³ Spearhead Acid (15% HCl) Spearhead
5 kg/m³ IC-3 (Iron Control) - pre-mixed
2 L/m³ AI-1 (Corrosion Inhibitor) - pre-mixed
2 L/m³ S-1 (Surfactant) - pre-mixed

Total Products Required

2 L AI-1 (Corrosion Inhibitor)
1 m³ HCl (15%)
4600 sm³ N2 (Gas)
20 tonne Sand (20/40)
109 m³ CO2 (Liquid)
5 kg IC-3 (Iron Control)
2 L S-1 (Surfactant)

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Ocean Energy - Hill County Havre Montana
Liquid CO2 Frac
Option 1 Version 3

Discounted Price

Amount	Description	Discount	Unit Price (Discounted, Area A)	Price (Discounted)
Services And Equipment				
7.5 m³/min	Blender (Pumping)	40.0%	$135.00 / m³/min	$1,012.50
2 unit	CO2 Storage Tank	40.0%	$1,560.00 / unit	$3,120.00
1 unit	CO2 Transport (Setup)	40.0%	$399.00 / unit	$399.00
1320 kW	Frac CO2 Pumping (kW, 0-35.0 MPa)	40.0%	$7.95 / kW	$10,494.00
1 unit	Frac Van (Setup)	40.0%	$2,478.00 / unit	$2,478.00
1 unit	Iron Truck (Setup)	40.0%	$972.00 / unit	$972.00
1 unit	Liquid CO2 Blender (Setup)	40.0%	$1,470.00 / unit	$1,470.00
2 unit	N2 Pumping Unit (Setup)	40.0%	$1,425.00 / unit	$2,850.00
				Sub-total: $22,795.50
Products				
2 L	AI-1 (Corrosion Inhibitor)	40.0%	$16.59 / L	$33.18
109 m³	CO2 (Liquid)	40.0%	$381.00 / m³	$41,529.00
1 m³	HCl (15%)	40.0%	$372.00 / m³	$372.00
5 kg	IC-3 (Iron Control)	40.0%	$7.92 / kg	$39.60
4600 sm³	N2 (Gas)	40.0%	$0.84 / sm³	$3,864.00
2 L	S-1 (Surfactant)	40.0%	$12.84 / L	$25.68
20 tonne	Sand (20/40)	40.0%	$246.00 / tonne	$4,918.77
				Sub-total: $50,782.23
Travel And Cartage				
109 m³ x 300 km	Cartage (Liquid CO2)	40.0%	$0.25 / m³ km	$8,240.40
20 tonne x 300 km	Cartage (Proppant)	40.0%	$0.61 / tonne km	$3,671.08
8 unit x 100 km	Frac Unit (Travel)	40.0%	$3.09 / unit km	$2,472.00
2 unit x 100 km	N2 Unit (Travel)	40.0%	$3.09 / unit km	$618.00
				Sub-total: $15,001.48
				Total Discounted Price: $88,579.21

All quantities (including mileage) are estimated, and are subject to change depending upon actual amounts used. Any service or materials required, but not mentioned will be at book price less discount. Any applicable taxes (eg: GST) will be added to the invoice. Book prices less discount are in effect for 30 days after the date shown. **Due to the uncertainty of energy costs, prices may change without notice.**

Third Party

	Cartage (Additional Chemicals)
	Fluid Cartage & Heating
	Wellhead Saver (Casing)

Figure 13 – p. 7 of 7

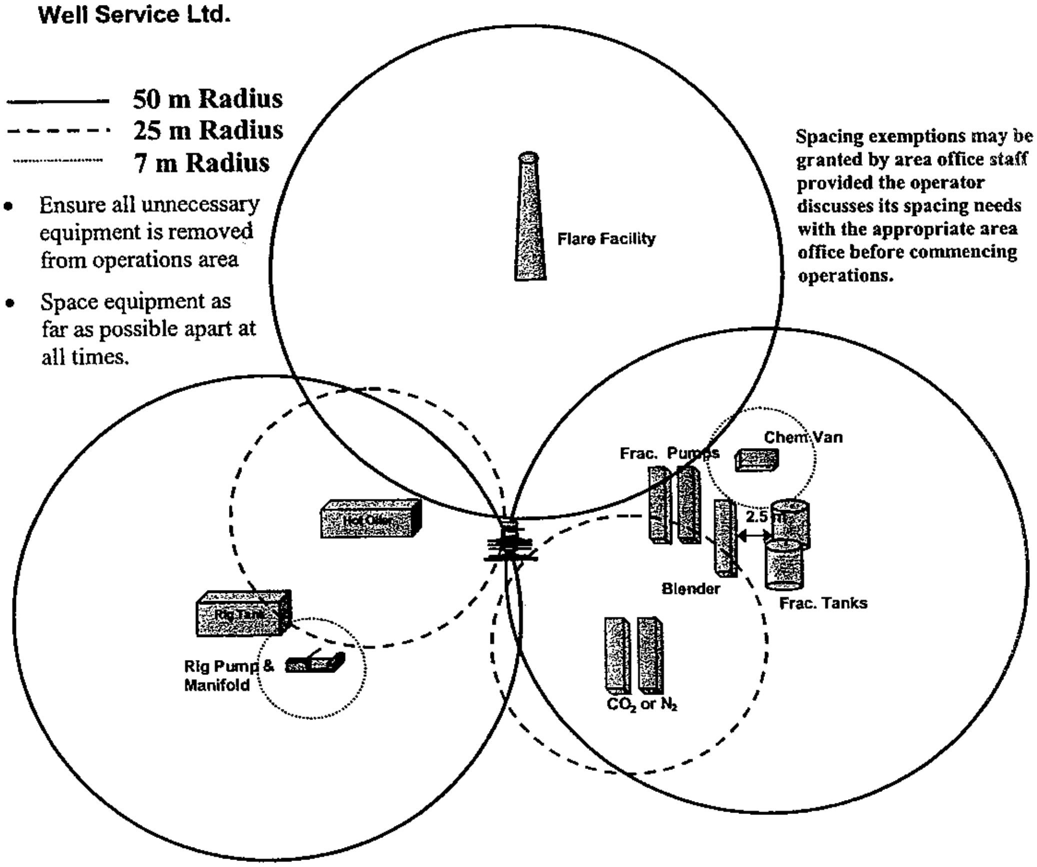
TRICAN
Well Service Ltd.

Frac Equipment Spacing On Location

50 m Radius (solid line)
25 m Radius (dashed line)
7 m Radius (dotted line)

- Ensure all unnecessary equipment is removed from operations area
- Space equipment as far as possible apart at all times.

Spacing exemptions may be granted by area office staff provided the operator discusses its spacing needs with the appropriate area office before commencing operations.



- All engines, air intakes or sources of ignition associated with fluid transfer must be at least 7 meters from open rig tank **(air shut off req'd).**
- All engines not associated with fluid transfer **(wellbore open)** must be at least 25 meters away from open rig tanks. **(Section 8.148, Oil and Gas Conservation Regulations)**
- All frac equipment must be a minimum of 25 meters away from open return or rig tanks if the tank is being used for circulating well or contains flammable material.

- Diesel engines without air shutoffs
- Gasoline Engines
- N_2 or CO_2 Units

Must be positioned no closer than 25 meters from the wellhead or tanks containing flammable fluid.

Sign: No Smoking	Access road free of congestion	Danger Poisonous Gas Sign

B. Proppant Size

20/40 (USS) sand proppant was currently being utilized in the conventional treatments and successful in the CO_2/sand stimulations, and on that basis was proposed in the design

C. Treatment Volume

The conventional treatments were relatively small, 200 sacks. The ability to transport proppant with liquid CO_2 is limited especially as the kh increases.

Efforts were to place the maximum proppant load of 44,100 pounds (for TriCan's blender). This plan would enable a maximum proppant volume to be realized and because the normal design trade off between the proppant volume and the damage resulting from the spent frac liquids becomes moot when compared to CO_2. The maximum benefit would be realized and there is no sustained penalty for increasing the volume of liquid CO_2 - because it will vaporize and flow from the reservoir as a gas.

A geologically similar but lower permeability formation was stimulated in Phillips County approximately 80 miles east of the test area and no problems were experienced placing the full 47,500 pound proppant load (FracMaster blender) in May 1998 (Group #5).

In actuality the sand proppant placed in-zone, following the removal of sand from the wellbore ranged from 8,500 to 24,900 lbs and averaged 16,400 lbs.

D. Treatment Volume Comparison – Conventional vs. CO_2/Sand

Generally, the wells in the vicinity of the Candidate Wells were not stimulated because of the low reservoir pressure. Should they have been, it would likely have been with a high quality N_2 foam containing approximately 20,000 pounds of 20/40 proppant.

XV. STIMULATION CHECKLIST

A stimulation checklist is attached (Figure 14). It summarizes the pertinent information regarding the reservoir, stimulation treatment, production, and marketing.

Figure 14 – p. 1 of 2

PETROLEUM CONSULTING SERVICES
(330) 499-3823
(330) 499-2280 (fax)

CO_2\SAND STIMULATION CHECKLIST
p. 1of2

Date: 05/18/00

Formation	Eagle Sand	Operator:	Ocean Energy - Amoco Bldg
Geologic Era:	Upper Cretaceous		1670 Broadway-Ste 2700
County:	Blaine		Denver, CO 80202
State:	Montana	POC:	Mr. Richard Myal (303) 308-8868
Field:	Tiger Ridge		Mr. Ken Sigl (713) 265-663?
Basin:	Sweet Grass Arch/Bear Paw Uplift		Mr. David Thomas (713) 265-6631

1. Reservoir	
a. Depth (ft):	1100-1600
b. Thickness (ft):	0-100
c. Porosity (%):	16-26
d. Permeability (md): (Unconfined core = 350)	10-60
e. Pressure (psig):	150-350(N of Mtn)
f. Temp (deg F):	70
g. Well Spacing (A):	80-160
2. Production	
a. Natural	
i. Gas (MMcf/d):	
ii. Oil (BO/d):	0
b. Post-Stimulation - Current Technology	
i. Gas (Mcf/d):	
ii. Oil (BO/d):	
3. Completion:	Set Through & Perforate
4. Frac Length Required (ft):	
5. Frac Gradient (psi/ft):	0.7-0.8
6. Frac Type (Gel Wtr, Foam, etc) - Present Technology:	N2 Foam
a. Breakdown Acid:	None
b. Foam Quality:	70-75
c. Breakdown Pressure (psi):	2200
d. Liquid Volume (bbl):	175
e. Sand Placed (sxs):	215
f. Rate (bpm):	27
g. Sand Conc (ppg):	4.0
h. Avg Treating Pressure (psi):	1200
i. Max Treating Pressure (psi):	1250
j. ISIP (psi):	800
k. Costs ($M)	
i. Service Company:	20
ii. CO_2 ($/ton):	200
iii. Tanks w/ Trucking:	2.4
iv. Service Rig:	0
v. Load Water Disposal:	$1.00/BBL
vi. Pit - Earthwork, Liner:	2.0

Figure 14 – p. 2 of 2

PETROLEUM CONSULTING SERVICES
(330) 499-3823
(330) 499-2280 (fax)

CO_2\SAND STIMULATION CHECKLIST
p. 2 of 2

Date: 05/03/00

Formation: Eagle Sand   Operator: Ocean Energy

7. Load Water	
a. Vol Returned (bbls) (%): (Low Pressure Area Tiger Ridge)	10
b. Time Required (days):	Lengthy
c. Vol Retained (bbls):	90
8. Casing - Candidate Wells	
a. Dia (in):	4.5
b. Weight (lb/ft):	10.50
c. Grade:	K-55
d. MWP (psi): (4790 psi interval yield @ 80%)	3,830
9. Perforations - Candidate Wells	
a. Depth (ft):	
b. Number:	5
10. Calorific Value (BTU/cuft):	970
11. Pipeline Pressure (psi):	15-18
12. Allowable CO_2 concentration in sales line (%)	2 (Many Islands)
13. Gas Transporter:	Many Islands
14. Gas Purchaser:	Montana Pwr/Great Lakes
a. Purchase Price (\$/dth): (Net bank @ wellhead)	1.50/Mcf
15. EUR with Current Tech	
a. Gas (MMcf):	
b. Oil (MBO):	0
16. NPV with Current Tech (\$M):	
17. Predict Required EUR for Candidate Wells (\$M):	
18. Predict Required NPV for Candidate Wells (\$M):	
19. Comments:	

XVI. CRITERIA FOR SUCCESS

The evaluation was conducted within a controlled setting to enable an objective assessment of the production responses resulting from these stimulations to be made. The Candidate Wells had been completed in the target formation and were selected on the basis of their upside potential for production rate improvement, a commercial volume of remaining reserves, and mechanical suitability for this demonstration (number of perforations & tubing diameter). The proposed Candidates had a sufficient background production history to provide the basis for comparing the post-stimulation production rates following the CO_2/Sand stimulations.

A. Establishing success criteria

The completion, remaining production, and some reservoir properties of the Candidate Wells were obtained and are summarized as:

Vell	S - #	T	Upr Eagle	Mid Eagle	Lwr Eagle	PB Req'd	H_2O	Stim Type	Rem	Skin	Prod	Pi	P*
		°F	Perfs	Perfs	Perfs		Lvl	Sxs, Bbls	MMcf		Mcf/d	Psi	Psi
T30N-R18E													
-B Ranch	02-05	72	1120-1202 1134–1197w/12	1222-1260 1220–1261w/ 8	1283-1290 None	No	TBD	None	484.345	TBD	35	170	TBD
Kane	05-08	72	1359-1334 1362-1380w/22	1436-1502 1388-1408w/ 26	1515-1538 None	Yes@1420	TBD	None	359.000	+2.00	100	175	95
ane	05-05	72	1094-1142 1110–1136w/42	1168-1233 1170-1220w/ 74	1283-1290 None	Yes@1150	TBD	None	96.700	+12.9	60	297	83.5
Blackwood	06-09	72	1142-1188 1144–1147w/20	1241-1288 1156-1162w/ 18	1302-1328 None	No	TBD	None	986.500	+2.83	220	222	114
ane	04-12	72	1238-1301 1238-1284w/71	1316-1383 1316–1375w/112	1395-1422 None	Yes@1294	TBD	None	460.568	+6.74	100	204	107
S-B Ranch	02-11	72	1052-1128 1068–1102w/16	1157-1238 1164–1204w/ 8	1250-1252 None	No	TBD	None	853.946	-1.82	180	225	TBD

The Criteria for success has been developed for each Candidate Well (the calculations for each well are included in their individual well sections) and is based on the following assumptions:

1. An economic success required that the cost benefit associated with the production rates resulting from the CO_2/Sand stimulations will have to exceed the pre-stimulation

production revenues by a discounted cash flow which equals or exceeds the cost of the treatment

2. Capital cost for the CO_2/Sand stimulation treatment: $86,000. This was a previous estimate which was at the time considered to likely be greater than the actual cost. In that event the production hurdle rates will be recalculated using the actual treatment cost.

   a. Market price: $2.50/dth – fixed
   b. Calorific value: 1000 BTU/CF
   c. Discount rate: 25%
   d. Production decline rate: Variable and driven by the production projections supplied by Ocean.
   The evaluation was not further burdened by the operating expenses because they are presently being incurred and would be the same irrespective of the treatment.

These inputs were used to determine the following total uninterrupted and unencumbered minimum annual production volumes as indicated below, necessary for an economic success.

The methodology was to project the production from the historical production rates for each well, and then to add an incremental production rate to compensate for the cost of the treatment. The total of these two components, the projected production rate and the incremental value to offset the stimulation cost, equals the minimum total production rate required for an economic success.

The individual production projections and the incremental rates necessary to provide the discounted cash flow have been calculated on an annual basis, for five years and are included in the individual well sections, and are summarized:

T30N-R18E		Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Total
Well	# - S	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)
From:		06/01/02	06/01/03	06/01/04	06/01/05	06/01/06	06/01/02
Through:		05/31/03	05/31/04	05/31/05	05/31/06	05/31/07	05/31/07
S-B Ranch	02-05	25,199	21,421	18,208	15,474	13,153	93,455
Blackwood	06-09	90,383	85,593	81,057	76,761	72,692	406,486
Kane	05-08	47,626	42,501	37,927	33,845	30,203	192,102
Kane	05-05	33,063	24,485	18,134	13,428	9,944	99,054
Kane	04-12	51,348	46,873	42,789	39,061	35,658	215,729
S-B Ranch	02-11	78,306	71,865	65,954	60,530	55,551	332,206

Ocean concurred that these production projections will serve as the basis for establishing the success criteria, and if the actual production volumes from these Candidate Wells exceed these tabulated annual production volumes, subject to adjustments for any non-producing intervals, then Ocean agreed that the CO_2/Sand stimulation process will have resulted in an economic benefit.

B. Conclusions

Summarizing, the CO_2/Sand stimulation process were to be considered to be economically successful if the total annual production from the proposed Candidate Wells, subject to any corrections as mentioned above, exceeded these volumes.

XVII. PRE-TEST CONCLUSIONS

A. The Upper and Middle Eagle Sands in the Test Area were considered likely to benefit from the CO_2/Sand stimulation process because of the absence of liquids in an area known to incur reservoir damage from stimulation liquids, and the additional benefits of the proppant could result in increased production rates.

B. The Operator, Ocean Energy, Inc. (Ocean) was the largest gas producing company in Montana and is the operator of record for approximately 650 producing gas wells in the north-central area of the state, southeast of Havre.

C. A Canadian-based pumping service company with the ability to perform these liquid CO_2/Sand treatments, exceptional technical ability, outstanding equipment, was in reasonably close proximity, and provided a cost-competitive bid.

D. Ocean could derive a significant benefit from the non-damaging CO_2/Sand stimulation treatments, and had offered six Candidate Wells and requested participation in demonstrating this technology under the DOE's cost-shared demonstration project.

E. The Candidate Wells which all produce from the Upper and Middle Eagle Sand members.

F. These wells are presently producing wells and the pre-stimulation production for each well has been utilized to project required production rates to establish an economic success based on:

1. A capital cost for the CO_2/Sand stimulation treatment: $86M (which was a previous estimate)
2. Market price: $2.50/dth – fixed
3. Calorific value: 1000 BTU/CF
4. Discount rate: 25%
5. Production decline rate: Variable and driven by the production projections supplied by Ocean.

G. The economically justifiable break-even production improvement ratios to substantiate the increase in stimulation costs based on net gas market prices excluding royalties, taxes, etc. are:

Well	# - S	Rem MMcf)	Skin	Prod Mcf/d)	Req'd Prod Improvement Ratio
S-B Ranch	02-05	484.345	TBD	35	2.77
Blackwood	06-09	986.500	+2.83	220	1.18
Kane	05-08	359.000	+2.00	100	1.46
Kane	05-05	96.700	+12.9	60	2.34
Kane	04-12	460.568	+6.74	100	1.40
S-B Ranch	02-11	853.946	-1.82	180	1.23

H. Three of the Candidate Wells contained a large number of perforations which were considered to be too many and for the CO_2/Sand process. If any of these three wells were selected, then the plan was to temporarily plug the lowermost perforations, which would eliminate the Middle Eagle sand from the stimulation treatment.

I. The wells were rank ordered by Ocean in their recommended sequence which is believed to provide the most benefit. This rank ordering results in the plugging of the Lower Eagle Sand in the wells which were ranked 3, 4, and 5, which almost dictates that at least one of the three Candidates will require plugging of the Middle Eagle and treating the Upper sand member only.

In order to properly measure the production response associated with the CO_2/Sand treatment, a producing period sufficient to eliminate the production from the un stimulated interval (Middle Eagle) was required.

Ocean's present plan was to install the temporary plug immediately before and to remove it shortly after the CO_2/Sand stimulation. This procedure will allow for the stimulation of only the Upper Eagle while comparing the post-stimulation production from both the Upper and Middle Sands.

J. The costs of the stimulations were recognized to be potentially greater than bid because it was based on performing the stimulations in April when the oilfield activity is at minimum level because of road weight limit restrictions during the spring "break up". The bid was extended at a discount of 40%, an earlier bid prepared last September included a discount of 31%.

If the higher discount rate was rescinded because of a post-April treatment execution, then the three-well total cost would increase from $187,265 to $215,735 (US).

K. The treatments could be performed in July. (They were executed in late September, 2002, and the service company honored the higher discount rate).

XVIII. DOE APPROVALS

A request for stimulating six Candidate Wells was submitted to the DOE (June, 2002). Following some interrogatories (Figure 15) and a conference call to Ocean from a meeting being held at DOE's Morgantown, WV offices which resulted in four of the Candidates being selected.

Well	# - S	Rem (MMcf)	Skin	Prod (Mcf/d)	Req'd Prod Improvement Ratio
S-B Ranch	02-05	484.345	TBD	35	2.77
Kane	05-08	359.000	+2.00	100	1.46
Kane	05-05	96.700	+12.9	60	2.34
Blackwood	06-09	986.500	+2.83	220	1.18

Subsequent approvals for the treatments were extended by the DOE and the four wells were stimulated in September 2002.

Figure 15 – p. 1 of 4

Review of Candidate Well Package No. 7B
Ocean Energy
Eagle Sand, Blaine County, Montana

By: Bill Schuller
E^2S/EG&G
July 2, 2002

Background:

Ocean Energy is producing gas from the partially depleted Eagle Sandstone unit in Township 30N, Range 18E, Blaine County, Montana. The partially depleted reservoir does not have sufficient energy to recover any fluid used in well stimulation and, therefore, wells drilled and completed within the partially depleted reservoir are left unstimulated. Wells in the area are drilled over-pressure with drilling mud that infiltrates and further hampers production from the untreated reservoir.

Ocean Energy has requested the use of CO_2/sand stimulation technology being tested by the U.S. Department of Energy's National Energy Technology Laboratory through a contract with Petroleum Consulting Services, LLC of Canton, Ohio. CO_2/Sand stimulation uses liquid carbon dioxide as the proppant carrier fluid. Because the CO_2 converts to a gas under normal reservoir temperatures, CO_2 requires no additional reservoir energy and is expelled from the reservoir during post-stimulation blowback. Sand proppant is left within the newly created fractures, thus reducing near wellbore mud damage.

Three wells are proposed for stimulation from six candidate wells offered by Ocean Energy. All six wells have been online producing gas with no reportable water production. Production dates range from a little over a year to more than 30 years. This CO_2/Sand stimulation demonstration project is unique since the wells have previous production histories. Previous CO_2/Sand stimulation projects have been conducted on new wells and production compared to older producing wells. The Ocean Energy project allows for any increased post-stimulation gas production to be determined immediately.

Review of Candidate Wells:

The six candidate wells, listed in importance for testing CO_2/Sand stimulation by Ocean Energy are: S-B Ranch 02-05, Blackwood 06-09, Kane 05-08, Kane 05-05, Kane 04-12, and S-B Ranch 02-11. Advantages/disadvantages of each well are reported in the following discussion.

S-B Ranch 02-05:

Both wells S-B Ranch 02-05 and 02-11 are separated from the other four candidate wells by several miles. Selection of either or both of these wells as part of the three test wells

Figure 15 – p. 2 of 4

would make a single isolated well in either the S-B Ranch area or the other area. This would make it difficult to determine any abnormalities that might occur in the single well area.

The location of S-B Ranch 02-05 would suggest it is both pressure and production depleted. Well S-B Ranch 02-05 currently produces 35 Mcf/d, the lowest production of any of the proposed wells. Initial open flow was 160 Mcf/d, one-third of the second lowest candidate well, Blackwood 06-09, which had a reported open flow of 510 Mcf/d. Reservoir pressure is 170 psi, again the lowest of the proposed wells. Addition of 20 perforations before CO_2/Sand stimulation may improve production, but adds another element to the equation as to what contributed to any enhanced production, the additional perforations, the stimulation, or both. It is doubtful based on all these criteria that the well would be able to meet the required 2.77 production improvement necessary to deem the stimulation a success.

Blackwood 06-09:

The Blackwood 06-09 well has no significant problems and is a viable candidate well. The well has the highest current production (220 Mcf/d) and also has one of the higher reservoir pressures (222 psi). CO_2/Sand stimulation should reduce the current +2.83 skin, thus allowing the well to achieve the required 1.18 production improvement ratio. Since the Kane 05-05 well in the same area is only to be stimulated in the Upper Eagle formation, the Blackwood 06-09 well should also only be stimulated in the Upper Eagle. Stimulation of both the Upper and Middle Eagle adds to the complexity of the problem of determining the actual stimulation benefits, especially if compared with wells not stimulated in the Middle Eagle. If both zones are stimulated, they should be isolated and metered separately.

Kane 05-08:

The Kane 05-08 well is another viable candidate well. Current design is to set a temporary bridge plug and stimulate both the Upper and Middle Eagle formations. Since only 8 feet separates the bottom perforations in the Upper Eagle and top perforations in the Middle Eagle, stimulation of only the Upper Eagle may be impossible. If the final decision is made to only stimulate the Upper Eagle to keep it consistent with the Kane 05-05 well, a tracer should be used to determine if the stimulated fracture grew down into the Middle Eagle formation. If both zones are stimulated, production should be isolated and metered separately.

Kane 05-05:

The Kane 05-05 well had the highest initial production potential (1075 Mcf/d) of all the candidate wells and would suggest the well should be performing better than its current production of 60 Mcf/d. This is especially true since the well also has the highest reservoir pressure (297 psi) of all the candidate wells. A high calculated skin of +12.9 would indicate drilling fluid damage could be restricting production, making this an excellent candidate for CO_2/Sand stimulation to reduce skin effects. The well has 42 perforations in the Upper Eagle and an additional 74 perforations in the Middle Eagle formation. Due to the large number of perforations, a temporary bridge plug is to be set between the formations and only the Upper Eagle formation is to be stimulated. A total of 34 feet separate the bottom Upper Eagle perforations and top Middle Eagle perforations. Any downward growth outside the stimulated formation will probably connect both formations. Thus this well becomes an obvious candidate for tracer testing to determine fracture vertical extent and migration outside the stimulated formation.

Kane 04-12:

The Kane 04-12 well is to stimulated only in the Upper Eagle formation. Previous CO_2/Sand stimulation experience has indicated the total number of perforations should be limited to approximately 40 to reduce screen-out of the sand during stimulation. The Upper Eagle formation within the Kane 04-12 well has 71 perforations; nearly double the maximum number of perforations. The large number of perforations places the well in a high risk for sand screen-out and should be withdrawn as a candidate well.

S-B Ranch 02-11:

As with the S-B Ranch 02-05 well, the S-B Ranch 02-11 well is separated from the other four candidate wells. Since a three well stimulation program is planned, selection of either or both S-B Ranch wells would create a one well test area, either at the S-B Ranch area or the Blackwood/Kane area. A calculated skin of –1.82 indicates drilling mud is not damaging this well and in fact, the well may have encountered a natural fracture. Additional stimulation could further reduce the skin effect, but may not show a significant increase in production to offset the stimulation costs.

Recommendations:

The following recommendations are made based on the previous discussions of each candidate well:

- Preferred wells for testing CO_2/Sand stimulation are:
    - Blackwood 06-09
    - Kane 05-08
    - Kane 05-05
- The Blackwood 06-09 and Kane 05-08 wells should only be stimulated in the Upper Eagle formation to be consistent with the Kane 05-05 well. If both formations are stimulated, the zones should be isolated and metered separately. Zonal isolation and metering should also be conducted in the Kane 05-05 well for consistent interpretation of results.

Figure 15 – p. 4 of 4

- Tracer testing should be conducted in the Kane 05-05 well to determine if the stimulation broke into the underlying, unstimulated Middle Eagle formation. Tracer testing should not be undertaken until at least the second well to determine if the CO_2/Sand stimulation can actually be conducted on the Eagle formation.

XIX. FIELD ACTIVITIES

A. Preparations

The wells were perforated where needed (where there were too few) during the week prior to the treatments, CO_2 was procured, and the service company mobilization from Red Deer, Alberta initiated. Four portable CO_2 storage trailers (80 tons each) which provided the storage capacity for two stimulation treatments were mobilized.

B. Stimulations

1. Candidate Well # 1 – S-B Ranch 02-05 (25-041-22955)

The well was perforated with 30 holes over a 136 foot interval from 1,125 to 1,261 feet.

The pressurized blender was transported to the well site on the day of the treatment, September 15, 2002 and filled with 20/40 sand. The treatment was then executed at a breakdown pressure of 1,820 psi at the perforations, 10,300 lbs of proppant and 432 bbls (83 Tons) of CO_2 were pumped at an average rate and pressure of 37.8 barrels per minute and 2,318 psi respectively. The maximum sand concentration was 2.4 lbs per gal, and averaged 1.2, the maximum rates and pressures were 39.6 Bpm and 3,115 psi respectively (Figure 16).

The treatment screened out at a sand concentration of 2.4 ppg with 1,800 lbs of proppant in the wellbore leaving 8,500 lbs of proppant in-zone.

Figure 16 – p. 1 of 4

TRICAN WELL SERVICE LTD.

Post Frac Summary

OCEAN ENERGY

S-B Ranch 2-5-30-18

Eagle (Gas) 345.7 m - 384.4 m

LIQUID C02 FRAC Pumped On Sep 15, 2002

Pumping Configuration:	Casing
Average Treatment Rate:	6.20 m^3/min
Average Treatment Pressure:	16,000 kPa
ISIP:	2,000 kPa
15 min SIP:	N/A
Max DH Proppant Concentration:	290 kg/m^3

Figure 16 – p. 2 of 4

TRICAN — CO2 FRAC TREATMENT REPORT

Customer Information

Customer:	Service Order	Date:	
Ocean Energy	C38873	Sept. 15/2002	Arrive on Location: 7:00 Leave Location: 13:00

Well Name:	Location:	Formation:			
Ocean Energy - Blair	S-B2-5-30-18	Eagle (Gas)			
	From:	To:	Pumping Configuration Down Well:		Dead Leg:
	1134.0	1261.0	casing		0.0
			Bottom Hole Temperature:		Deadleg Fluid:
			75.0 °F		0.0
	Size (in)	Weight (lbs/ft)	Grade	Depth (ft)	Volume (bbl)	Packer Depth:
						0.0
Casing	4.5	10.50	J-55	1134.0	16.03	
PBTD	1588.0			Total	16.03	

Fluid Additives	Mixed on the fly: Conc.	Units	Total	Fluid Additives	Premixed in tanks: Conc.	Units	Total
	0.0	l/m³	0.0		0.0	l/m³	0.0
	0.0	l/m³	0.0		0.0	l/m³	0.0
	0.0	l/m³	0.0		0.0	l/m³	0.0
	0.0	l/m³	0.0		0.0	l/m³	0.0
	0.0	kg/m³	0.0		0.0	kg/m³	0.0
	0.0	kg/m³	0.0		0.0	kg/m³	0.0

		Density		
			Total Fluid Pre-mixed	0.0 m³
Frac Type	Liquid CO2 Frac	0	Total Fluid Mixed	0.0 m³
Frac Fluid Type	0	0	Hole Volume	18.0 m³
Flush Fluid	0	0	Flush Volume	0.0 m³
Deadleg Fluid	n/a	0		

Acid Requirement: 0.0 m³ 0.0 % HCL Acid

Acid Additives	Conc.	Units	Total
AI-1	0.0	l/m³	0.0
S-1	0.0	l/m³	0.0
IC-3	0.0	kg/m³	0.0
Methanol	0.0	l/m³	0.0

Proppant Type	Size	lbs	Pumped (lbs)	In Formation (lbs)	In Pipe (lbs)
reg	20/40	44,900 lbs	10340 lbs	8580 lbs	1760 lbs

Spearhead	Pad Size	Treatment Start Time:	Treatment Finish Time:	Screenout	Sand Conc. at Perfs (lb/gal)
no	190.2	10:58.2	11:09.1	yes	2.4

Breakdown Pressure	Volume to fill hole	Max Pressure	Average Pressure	ISIP	AveragePad Pressure	15 min SIP	Average Rate	Frac Gradient
2203.0	629.0	3115.0	2318.0	290.0	2391.0	n/a	37.8	255.7

Time (min)	Treating Pressure Casing		Blender Slurry Rate (m³/min) Start of Stage	Blender Slurry Volume (m³) Per Stage	Blender Slurry Cum. At End of Stage	Blender Clean Rate (m³/min) Start of Stage	Blender Clean Rate End of Stage	Blender Clean Volume (m³) Per Stage	Blender Clean Cum. At End of Stage	Blender Proppant Concentration (kgs/m³) Start of Stage	Concentration End of Stage	Blender Proppant Total (kgs) Per Stage	Total Cum. At End of Stage	Breaker Loading per m³ per Stage	Procedure & Remarks
5.60	17.1		6.0	30.2	30.2	6.00	6.00	30.2	30.2						Pad.
6.40	16.7		6.3	5.6	35.8	6.11	5.94	5.4	35.6	50	100	405	405		Start sand ramp.
8.20	16.2		6.3	10.7	46.5	5.94	5.84	10.3	45.9	100	130	1,185	1,590		Inc. Conc.
10.00	14.5		5.7	10.7	57.2	5.08	4.82	9.8	55.7	200	300	2,450	4,700		Inc. Conc.
11.30	15.2		5.7	5.7	62.9	5.70	5.70	5.7	61.4						Screen out, shutdown pumps.
															Open well, to atmosphere, bleed well down
0.00	0.0														Start pad
2.90	21.6		3.6	7.5	7.5	3.60	3.60	7.3	7.3						pressure up, shutdown pumps.
Time	Treating Pressure		Rate	Slurry Volume (bbl)		Rate (bbl/min)		Clean Volume (bbl)		Concentration		Prop Total (lbs)			
	2446		37.7	190.0	190	37.7	37.7	190.0	190						Pad.
6.4	2389		39.6	34.9	225	38.5	37.4	34.0	224	0.4	0.8	891	891		Start sand ramp.
8.2	2318		39.6	67.6	292	37.4	36.7	64.8	289	0.8	1.1	2606	3496.9		Inc. Conc.
10.0	2074		35.9	67.5	360	32.0	30.3	61.6	350	1.7	2.5	5390	10340		Inc. Conc.
11.3	2175		35.9	35.9	396	35.9	35.9	35.9	386	0.0	0.0	0	0		Screen out, shutdown pumps.
															Open well, to atmosphere, bleed well down
0.0	0														Start pad
2.9	3090		22.6	47.2	47	22.6	22.6	45.9	46						pressure up, shutdown pumps.

Trican Rep.	Customer Rep.
Ryan Robinson	James Wingo

Figure 16 – p. 3 of 4

TRICAN WELL SERVICE LTD.

Treatment Data Charts

OCEAN ENERGY
Eagle (Gas) 2-5-30-18 345.7 m - 384.4 m
LIQUID C02 FRAC, Down Casing September 15, 2002

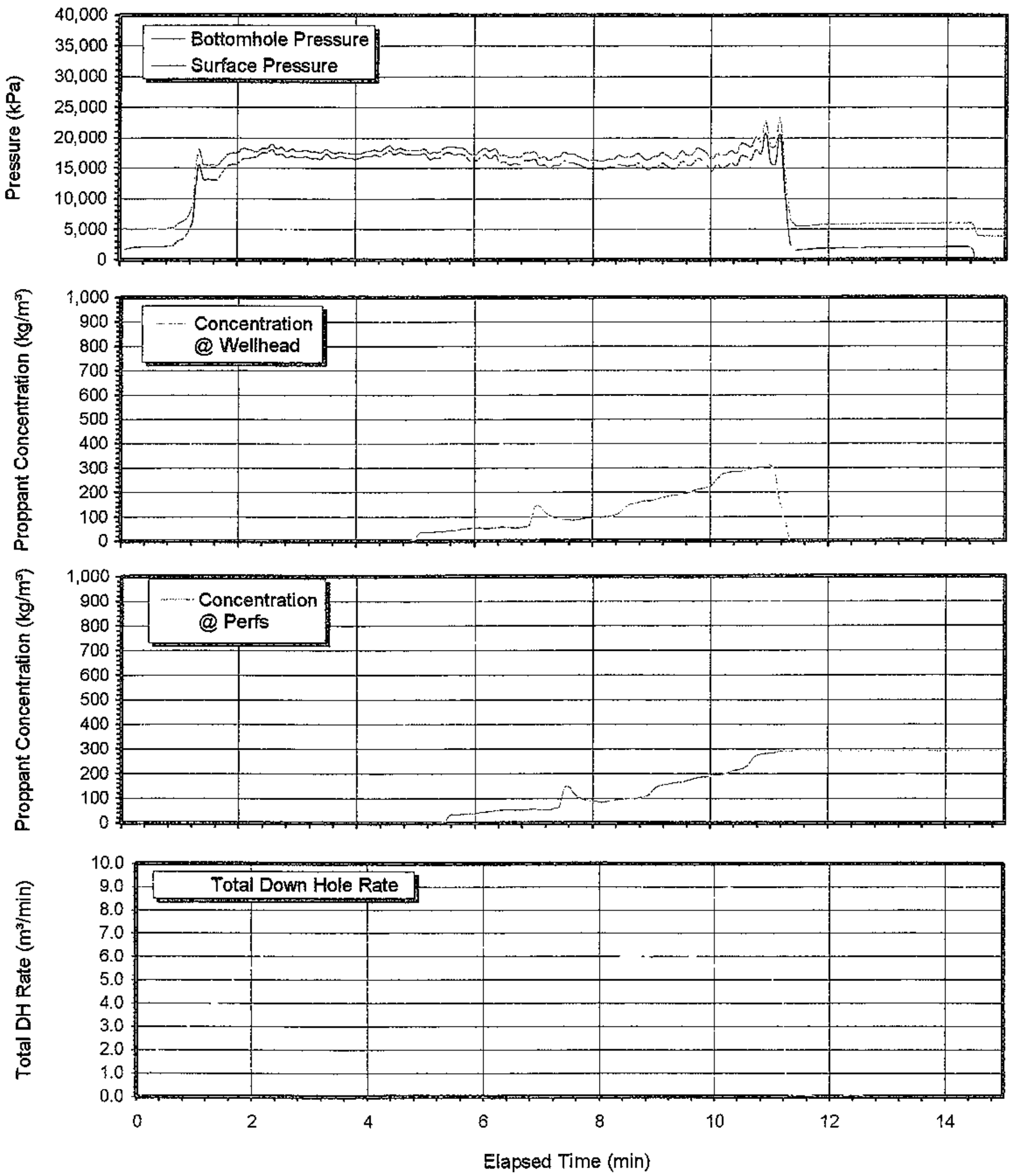
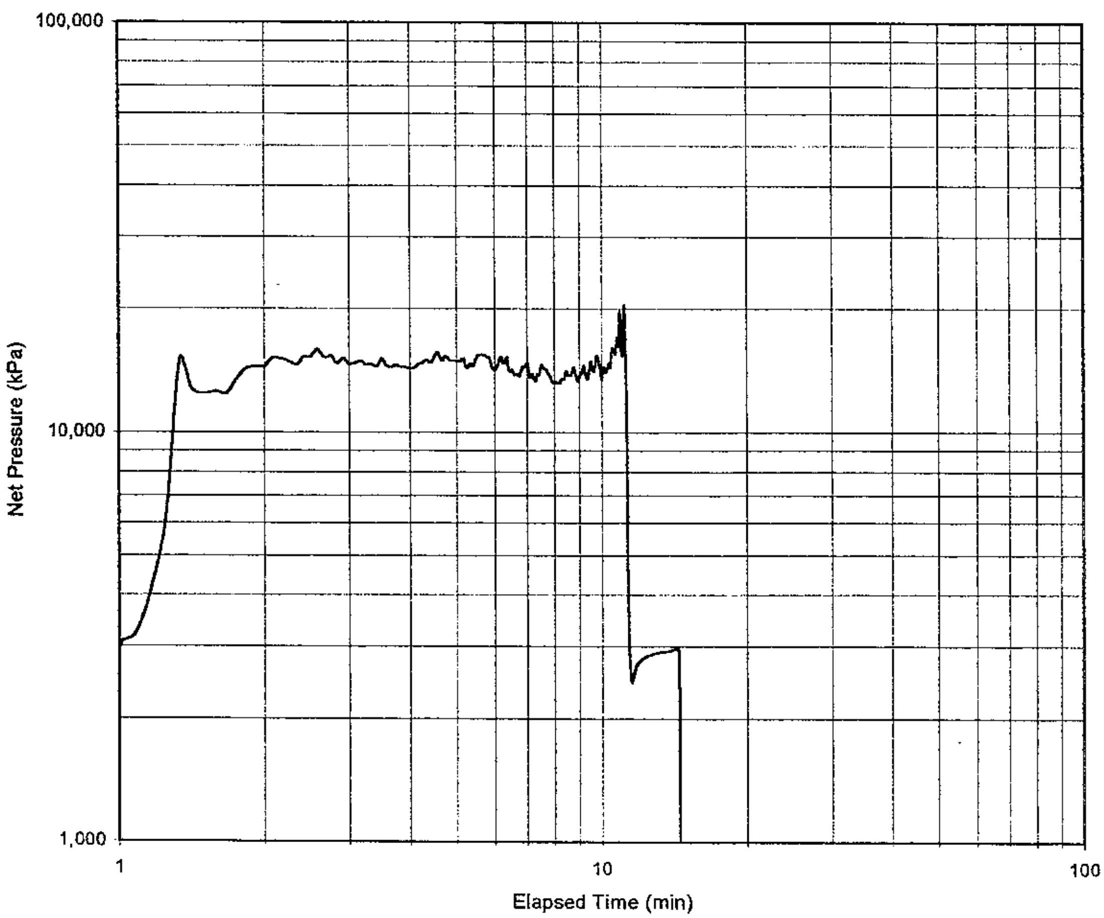


Figure 16 – p. 4 of 4

TRICAN WELL SERVICE LTD.

Net Pressure Chart
(Based On 3,000 kPa Closure)

OCEAN ENERGY
Eagle (Gas) 2-5-30-18 345.7 m - 384.4 m
LIQUID C02 FRAC, Down Casing September 15, 2002



2. Candidate Well #2 – Kane 05-08 (25-041-22279)

The Kane 05-08 was perforated with 48 holes over a 46 foot interval from 1,362 to 1,408 feet.

The pressurized blender was transported to the well site on the day of the treatment, September 17, 2002 and filled with 20/40 sand. The treatment was then executed at a breakdown pressure of 2,900 psi at the perforations, 27,300 lbs of proppant and 835 bbls (161 Tons) of CO_2 were pumped at an average rate and pressure of 31.0 barrels per minute and 3,032 psi respectively. The maximum sand concentration was 2.3 lbs per gal, and averaged 1.0, the maximum rates and pressures were 32.5 Bpm and 3,147 psi respectively (Figure 17).

The instantaneous shut in pressure was 686 psi which results in a gradient of 0.5 psi/ft. The stimulation pressure-rate history plot is included. The in zone proppant volume was estimated 24,900 pounds.

Figure 17 – p. 1 of 4

TRICAN WELL SERVICE LTD.

Post Frac Summary

OCEAN ENERGY

Kane 5-8-30-18

Eagle (Gas) 415.24 m - 429.26 m

LIQUID CO2 FRAC Pumped On Sep 17, 2002

Pumping Configuration:	**Casing**
Average Treatment Rate:	**4.83 m^3/min**
Average Treatment Pressure:	**21,200 kPa**
ISIP:	**4,800 kPa**
15 min SIP:	**3,100 kPa**
Max DH Proppant Concentration:	**370 kg/m^3**

Figure 17 – p. 2 of 4

TRICAN — CO2 FRAC TREATMENT REPORT

Customer Information

Customer	Service Order	Date	Arrive on Location / Leave Location
Ocean Energy	C38874	Sept. 17/2002	7:00 / 12:00

Well Information

Well Name	Location	Formation
Ocean Energy - Blai	Kane-5-8-30-18	Eagle (Gas)

	From	To	Pumping Configuration Down Well	Dead Leg
	1362.0	1408.0	casing	0.0
			Bottom Hole Temperature: 75.0 °F	[illegible]: 0.0
				[illegible] Depth: 0.0

	Size (in)	Weight (lbs/ft)	Grade	Depth (ft)	Volume (bbls)
Casing	4.5	10.50	J-55	1362.0	22.10
PBTD	1422.0			Total	22.10

Fluid Information

	Conc.	Units	Total		Conc.	Units	Total	0.0 m^3	Conc	Units	Total
								0.0 % HCL Acid			
	0.0	l/m³	0.0		0.0	l/m³	0.0				
	0.0	l/m³	0.0		0.0	l/m³	0.0	AI-1	0.0	l/m³	0.0
	0.0	l/m³	0.0		0.0	l/m³	0.0	S-1	0.0	l/m³	0.0
	0.0	l/m³	0.0		0.0	l/m³	0.0	IC-3	0.0	kg/m³	0.0
	0.0	kg/m³	0.0		0.0	kg/m³	0.0	Methanol	0.0	l/m³	0.0
	0.0	kg/m³	0.0		0.0	kg/m³	0.0				

			Total Fluid Pre-mixed	0.0	m³
Frac Type	Liquid CO2 Frac	0	Total Fluid Mixed	0.0	m³
Frac Fluid Type	0	0	Hole Volume	22.1	m³
Flush Fluid	0	0	Flush Volume	0.0	m³
Deadleg Fluid	n/a	0			

Sand Information

Proppant Type	Size	lbs	Pumped (lbs)	In Formation (lbs)	In Pipe (lbs)
reg.	20/40	44000.0	27280.0	26180	2420

Spearhead	Pad Size	Treatment Start Time	Treatment Finish Time	Screenout	Sand Conc. at Perfs (lb/gal)
no	185.8	9:52.2	10:21.5	no	2.25

Job Summary

Breakdown Pressure	Volume to fill hole	Max Pressure	Average Pressure	ISIP	Average Pad Pressure	10 min SIP	Average Rate	Frac Gradient
3081.5	23.9	3147.0	3032.0	686.0	2932.0	443.0	1659	503.7

Time (min)	Treating Pressure Casing		Blender Slurry Rate (m^3/min) Start of Stage	Blender Slurry Volume (m^3) Per Stage	Blender Slurry Volume Cum At End of Stage	Blender Clean Rate (m^3/min) Start of Stage	Blender Clean Rate End of Stage	Blender Clean Volume (m^3) Per Stage	Blender Clean Volume Cum. At End of Stage	Blender Proppant Concentration (kgs/m^3) Start of Stage	Concentration End of Stage	Total (kgs) Per Stage	Total Cum At End of Stage	Breaker Loading per m^3 per Stage	Procedure & Remarks
7.80	20.2		4.0	29.5	29.5	4.00	4.00	29.5	29.5						Pad.
11.50	21.7		4.8	18.8	48.3	4.80	4.66	18.6	48.1	0	50	465	465		Start sand ramp.
19.50	22.5		4.8	40.4	88.7	4.66	4.53	39.3	87.4	50	100	2,948	3,413		Inc. Conc.
22.70	21.9		4.8	26.5	115.2	4.53	4.28	25.1	112.5	100	200	3,765	7,178		Inc. Conc.
24.80	20.4		4.8	16.2	131.4	4.28	4.21	15.0	127.5	200	230	3,225	10,403		Inc. Conc.
28.40	18.3		4.8	2.8	134.2	4.21	3.96	2.5	130.0	230	350	725	12,400		Inc. Conc.
29.10	4.8		4.8	2.8	137.0	4.80	4.80	2.8	132.8				12,400		flush

Time	Treating Pressure		Rate	Slurry Volume (bbl)		Rate (bbl/min)		Clean Volume (bbl)		Concentration		Prop Total (lbs)			
7.8	2890		25.2	185.5	186	25.2	25.2	185.5	186						Pad.
11.5	3104		30.2	118.1	304	30.2	29.3	117.0	303	0.0	0.4	1023	1023		Start sand ramp.
19.5	3219		30.2	254.2	558	29.3	28.5	247.2	550	0.4	0.8	6485	7507.5		Inc. Conc.
22.7	3133		30.2	166.8	725	28.5	26.9	157.9	708	0.8	1.7	8283	15790.5		Inc. Conc.
24.8	2918		30.2	102.0	827	26.9	26.5	94.3	802	1.7	1.9	7095	22885.5		Inc. Conc.
28.4	2618		30.2	17.4	844	26.5	24.9	15.7	818	1.9	2.9	1595	27280		Inc. Conc.
29.1	687		30.2	17.6	862	30.2	30.2	17.6	835				27280		flush

Trican Rep	Customer Rep
Ryan Robinson	James Wingo

Figure 17 – p. 3 of 4

TRICAN WELL SERVICE LTD.

Treatment Data Charts

OCEAN ENERGY
Eagle (Gas) 5-8-30-18 415.24 m - 429.26 m
LIQUID CO2 FRAC, Down Casing September 17, 2002

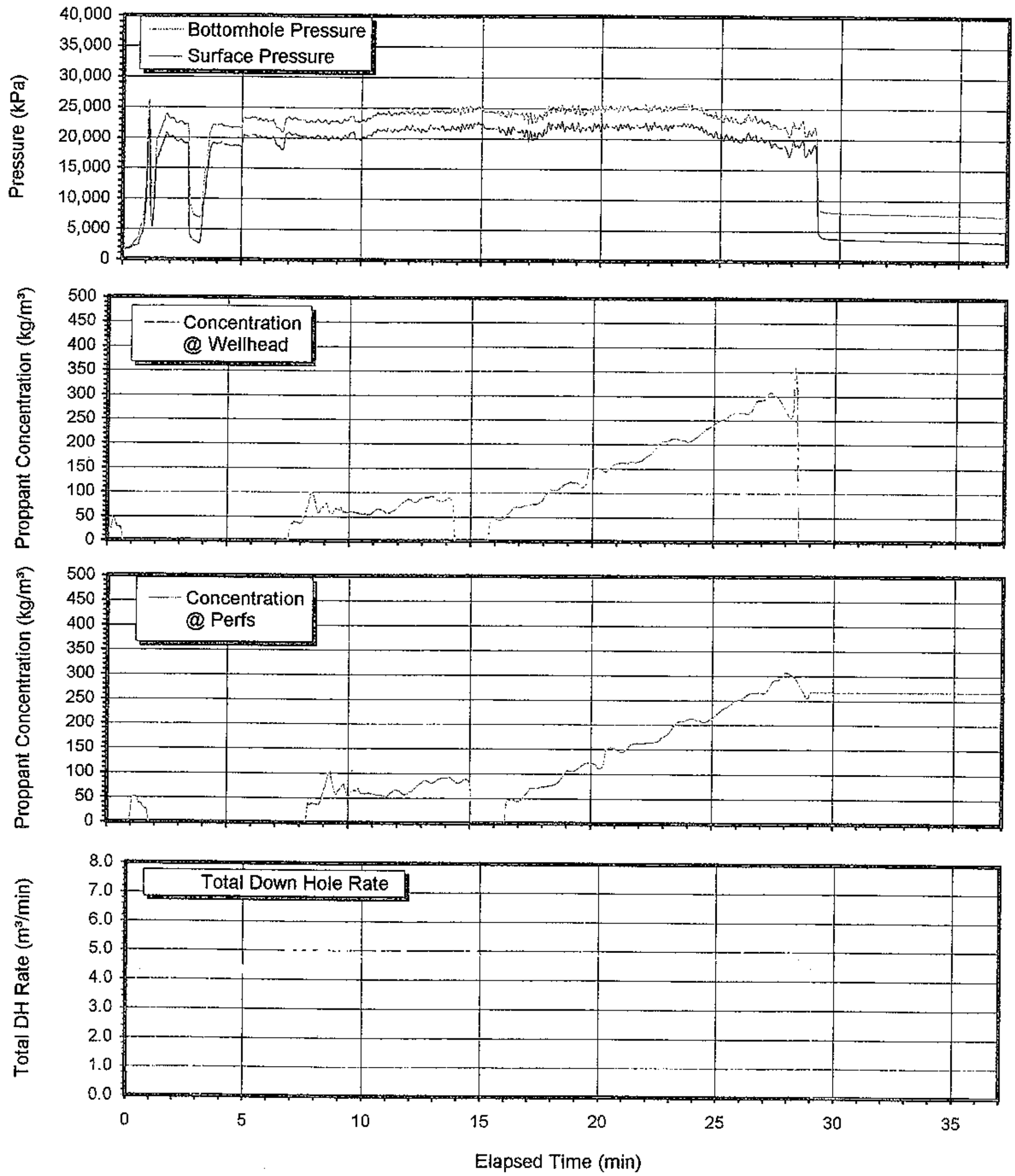


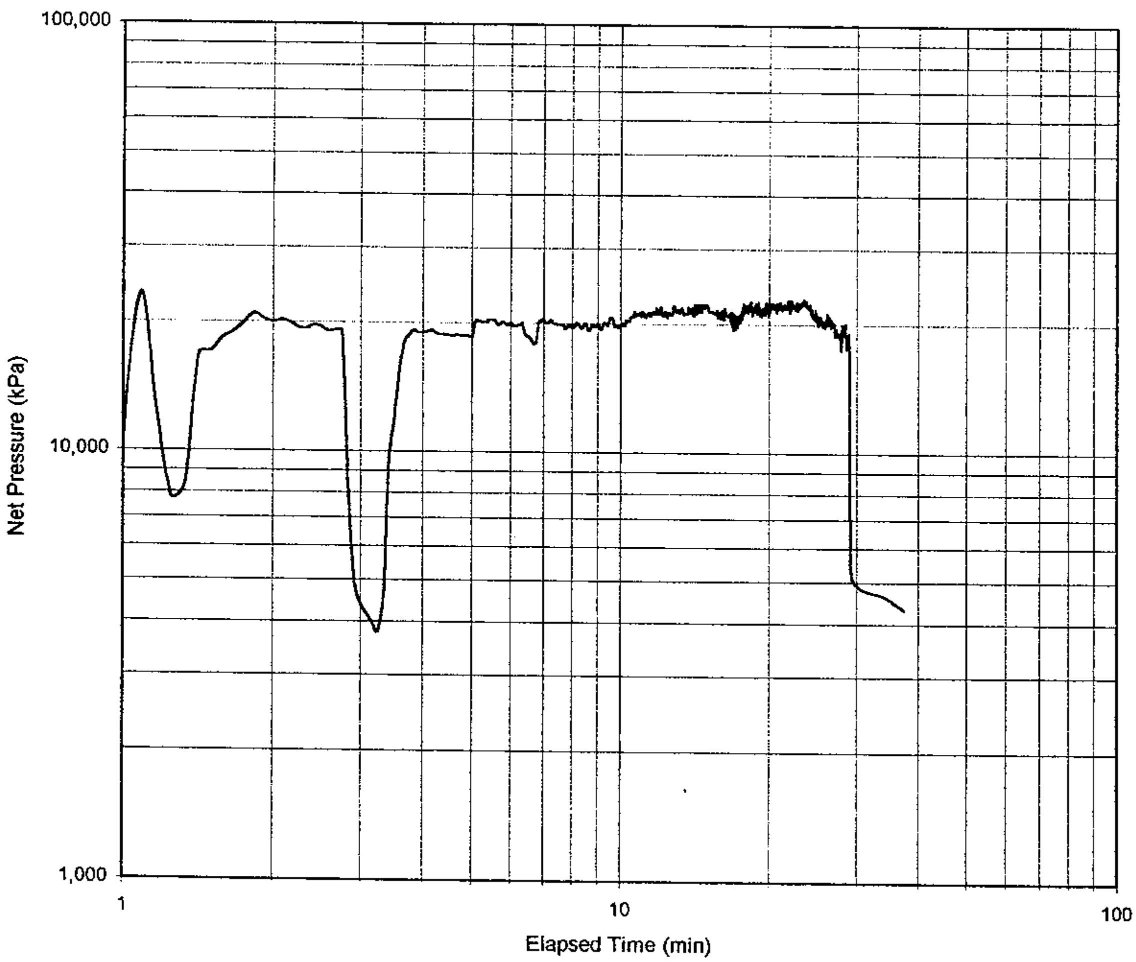
Figure 17 – p. 4 of 4

TRICAN WELL SERVICE LTD.

Net Pressure Chart

(Based On 3,000 kPa Closure)

OCEAN ENERGY
Eagle (Gas) 5-8-30-18 415.24 m - 429.26 m
LIQUID CO2 FRAC, Down Casing September 17, 2002



3. Candidate Well #3 - Kane 05-05 (25-041-22557)

The Kane 05-05 was perforated with 42 holes over a 26 foot interval from 1,110 to 1,136 feet.

The pressurized blender was transported to the well site on the day of the treatment, September 18, 2002 and filled with 20/40 sand. The treatment was then executed at a breakdown pressure of 2,385 psi at the perforations, 23,800 lbs of proppant and 815 bbls (157 Tons) of CO_2 were pumped at an average rate and pressure of 46.0 barrels per minute and 2,581 psi respectively. The maximum sand concentration was 2.4 lbs per gal, and averaged 0.9, the maximum rates and pressures were 50.3 Bpm and 3,495 psi respectively (Figure 18).

The stimulation pressure-rate history plot is included. The in zone proppant volume was estimated 21,800 pounds.

Figure 18 – p. 1 of 4

TRICAN
WELL SERVICE LTD.

Post Frac Summary

OCEAN ENERGY

Kane 5-530-18

Eagle (Gas) 338.4 m - 346.3 m

Liquid CO2 Frac Pumped On Sep 18, 2002

Pumping Configuration:	**Casing**
Average Treatment Rate:	**7.29 m^3/min**
Average Treatment Pressure:	**17,900 kPa**
ISIP:	**N/A Screened Out**
15 min SIP:	**2000 kPa**
Max DH Proppant Concentration:	**290 kg/m^3**

Figure 18 – p. 2 of 4

TRICAN — CO2 FRAC TREATMENT REPORT

Customer Information

Customer	Service Order	Date	Arrive on Location	Leave Location
Ocean Energy	C38876	Sept. 18/2002	9:30	15:00

Well Information

Well Name	Location	Formation
Ocean Energy-Kane	Kane 5-5-30-18	Eagle (Gas)

	From:	To:	Pumping Configuration Down Well			Dead Leg
	338.4	341.4	casing			0.0
	343.3	346.3	Bottom Hole Temperature			Deadleg Fluid
			24.0 °C			0.0
	Size (mm)	Weight (kg/m)	Grade	Depth (m)	Volume (m³)	Packer Depth
						0.0
Casing	114.3	14.14	J-55	338.4	2.87	
PBTD	350.6			Total	2.87	

Fluid Information

Fluid Additives	Mixed on the fly Conc.	Units	Total	Fluid Additives	Premixed in tanks Conc.	Units	Total
	0.0	l/m³	0.0		0.0	l/m³	0.0
	0.0	l/m³	0.0		0.0	l/m³	0.0
	0.0	l/m³	0.0		0.0	l/m³	0.0
	0.0	l/m³	0.0		0.0	l/m³	0.0
	0.0	kg/m³	0.0		0.0	kg/m³	0.0
	0.0	kg/m³	0.0		0.0	kg/m³	0.0

Acid: 0.0 m³ 0.0 % HCL Acid

Acid Additives	Conc.	Units	Total
AI-1	0.0	l/m³	0.0
S-1	0.0	l/m³	0.0
IC-3	0.0	kg/m³	0.0
Methanol	0.0	l/m³	0.0

		Density		
			Total Fluid Pre-mixed	0.0 m³
Frac Type	Liquid CO2 Frac	0	Total Fluid Mixed	0.0 m³
Frac Fluid Type	0	0	Hole Volume	2.9 m³
Flush Fluid	0	0	Flush Volume	0.0 m³
Deadleg Fluid	n/a	0		

Sand Information

Proppant Type	Size	Tonne	Pumped (tonne)	In Formation (tonne)	In Pipe (tonne)
reg	20/40	20.0	10.8	8.9	0.9

Spearhead	Pad Size	Treatment Start Time:	Treatment Finish Time:	Screenout	Sand Conc. at Perfs (kg/ m3)
no	26.6	12:37.5	12:57.1	yes	290.0

Job Summary

Breakdown Pressure	Volume to fill hole	Max Pressure	Average Pressure	ISIP	AveragePad Pressure	10 min SIP	Average Rate	Frac Gradient
15.0	4.0	24.1	17.6	n/a	12.5	n/a	7.3	

Time (min)	Treating Pressure Casing		Blender Slurry Rate (m³/min) Start of Stage	Blender Slurry Volume (m³) Per Stage	Blender Slurry Volume (m³) Cum. At End of Stage	Blender Clean Rate (m³/min) Start of Stage	Blender Clean Rate (m³/min) End of Stage	Blender Clean Volume (m³) Per Stage	Blender Clean Volume (m³) Cum. At End of Stage	Blender Proppant Concentration (kgs/m³) Start of Stage	Blender Proppant Concentration (kgs/m³) End of Stage	Blender Proppant Total (kgs) Per Stage	Blender Proppant Total (kgs) Cum. At End of Stage	Breaker Loading per m³ per Stage	Procedure & Remarks
4.30	12.5		5.0	26.6	26.6	5.00	5.00	26.6	26.6						Pad.
5.70	10.9		7.3	11.2	37.8	7.30	6.98	11.0	37.6	0	75	413	413		Start sand ramp.
7.60	20.0		7.3	20.7	58.4	6.98	6.88	20.0	57.6	75	100	1,750	2,163		Inc. Conc.
8.90	18.6		7.3	3.8	62.2	7.30	7.30	3.8	61.4	0	0	0	2,163		shut sand off
11.00	16.8		7.3	17.6	79.8	7.30	6.79	17.2	78.6	0	125	1,075	3,238		Start sand
15.50	20.0		7.3	36.2	116.1	6.88	6.51	34.3	112.9	100	200	5,145	8,383		Inc. Conc.
17.70	23.2		7.3	18.3	134.4	6.51	6.02	16.6	129.5	200	350	4,565	10,800		Inc. Conc.
															Shutdown pumps hit max pressure.

Time	Treating Pressure		Rate	Slurry Volume (bbl)		Rate (bbl/min)		Clean Volume (bbl)		Concentration		Prop Total (lbs)			
4.3	1788		31.4	167.3	167	31.4	31.4	167.3	167						Pad.
5.7	1559		45.9	70.2	237	45.9	43.9	69.2	236	0.0	0.6	907.5	907.5		Start sand ramp.
7.6	2861		45.9	129.9	367	43.9	43.3	125.8	362	0.6	0.8	3850	4757.5		Inc. Conc.
8.9	2661		45.9	23.9	391	45.9	45.9	23.9	386	0.0	0.0	0	4757.5		shut sand off
11.0	2403		45.9	110.7	502	45.9	42.7	108.2	494	0.0	1.0	2365	7122.5		Start sand
15.5	2861		45.9	228.0	730	43.3	40.9	215.7	710	0.8	1.7	11319	18441.5		Inc. Conc.
17.7	3319		45.9	115.2	845	40.9	37.9	104.4	815				23760		Inc. Conc.
															Shutdown pumps hit max pressure.

Trican Rep.	Customer Rep
Ryan Robinson	James Wingo

Figure 18 – p. 3 of 4

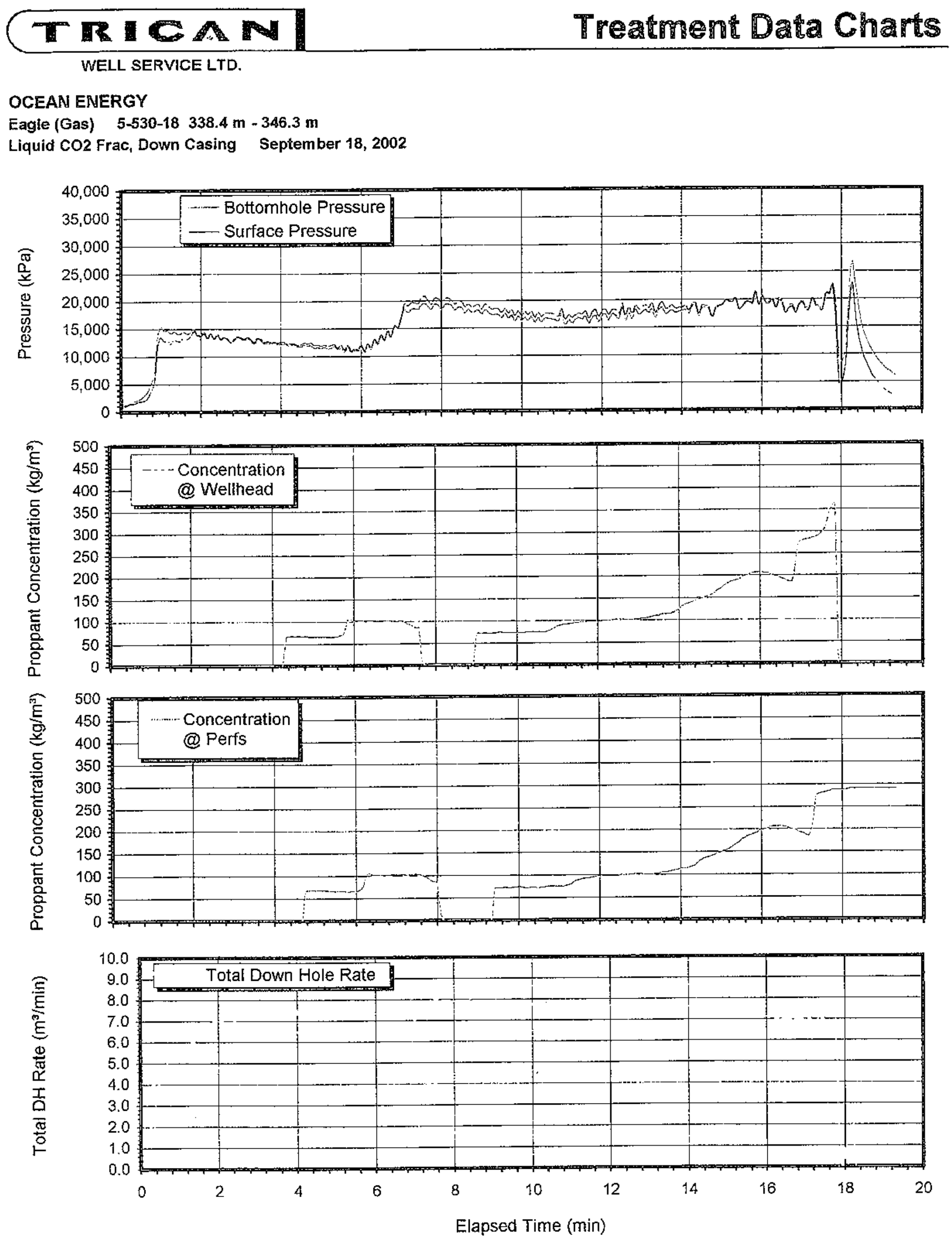
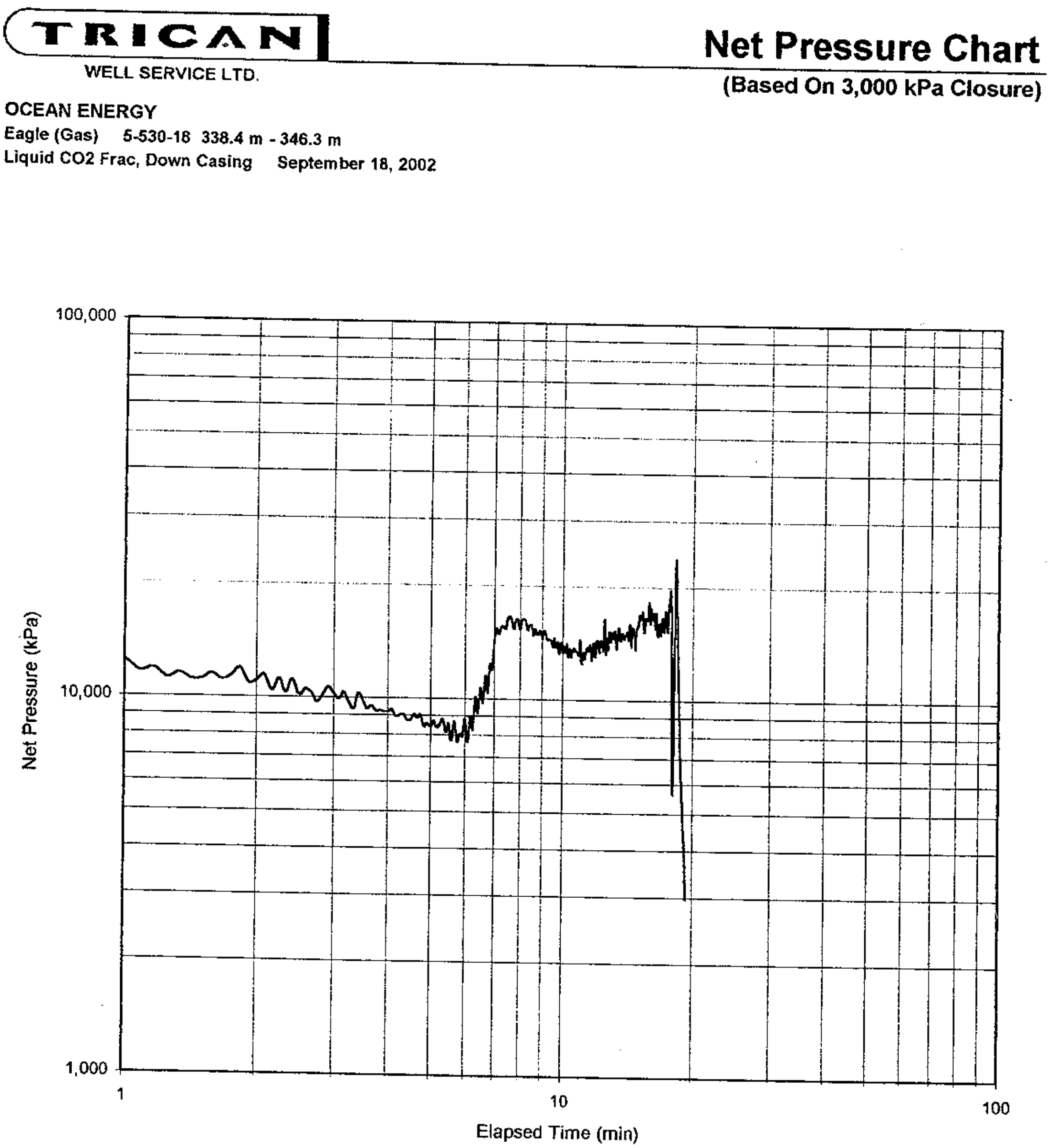


Figure 18 – p. 4 of 4



4. Candidate Well #4 – Blackwood 06-09 (25-041-22161)

The Blackwood 06-09 was perforated with 30 holes over a 18 foot interval from 1,144 to 1,162 feet.

The pressurized blender was transported to the well site on the day of the treatment, September 19, 2002 and filled with 20/40 sand. The treatment was then executed at a breakdown pressure of 3,570 psi at the perforations, 10,600 lbs of proppant and 633 bbls (122 Tons) of CO_2 were pumped at an average rate and pressure of 20.0 barrels per minute and 3,321 psi respectively. The maximum sand concentration was 1.3 lbs per gal, and averaged 0.6, the maximum rates and pressures were 28.0 Bpm and 3,408 psi respectively (Figure 19).

The instantaneous shut in pressure was 1,290 psi which results in a gradient of 1.1 psi/ft. The stimulation pressure-rate history plot is included. The in zone proppant volume was estimated 10,400 pounds.

Figure 19 – p. 1 of 4

TRICAN
WELL SERVICE LTD.

Post Frac Summary

OCEAN ENERGY

Blackwoods 6-9-30-18

Eagle (Gas) 348.8 m - 355.2 m

Liquid CO2 Frac Pumped On Sep 19, 2002

Pumping Configuration:	**Casing**
Average Treatment Rate:	**3.00 m^3/min**
Average Treatment Pressure:	**22,900 kPa**
ISIP:	**8,900 kPa**
5 min SIP:	**2,700 kPa**
Max DH Proppant Concentration:	**150 kg/m^3**

Figure 19 – p. 2 of 4

TRICAN CO2 FRAC TREATMENT REPORT

Customer Information

Customer	Service Order	Date	
Ocean Energy	C38877	Sept. 18/2002	Arrive on Location: 9:30 Leave Location: 14:30

Well Information

Well Name	Location	Formation
Blackwoods	6-9-30-18	Eagle (Gas)

	From:	To:	Pumping Configuration Down Well:	Dead Leg
	1144.1	1147.0	casing	0.0
	1155.9	1165.1	Bottom Hole Temperature: 75.0 °F	Deadleg Fluid: 0.0
	Size (in)	Weight (lbs/ft)	Grade	Depth (ft)	Volume (bbls)	Packer Depth: 0.0
Casing	4.5	10.50	J-55	1144.1	18.64	
PBTD	1193.3			Total	18.64	

Fluid Information

Fluid Additives	Mixed on the Fly Conc.	Units	Total	Fluid Additives	Premixed in Tanks Conc.	Units	Total
	0.0	l/m³	0.0		0.0	l/m³	0.0
	0.0	l/m³	0.0		0.0	l/m³	0.0
	0.0	l/m³	0.0		0.0	l/m³	0.0
	0.0	l/m³	0.0		0.0	l/m³	0.0
	0.0	kg/m³	0.0		0.0	kg/m³	0.0
	0.0	kg/m³	0.0		0.0	kg/m³	0.0

		Density		
Frac Type	Liquid CO2 Frac	0	Total Fluid Pre-mixed	0.0 m³
Frac Fluid Type	0	0	Total Fluid Mixed	0.0 m³
Flush Fluid	0	0	Hole Volume	18.6 m³
Deadleg Fluid	n/a	0	Flush Volume	0.0 m³

Acid Requirement: 0.0 m³ 0.0 % HCL Acid

Acid Additives	Conc.	Units	Total
AI-1	0.0	l/m³	0.0
S-1	0.0	l/m³	0.0
IC-3	0.0	kg/m³	0.0
Methanol	0.0	l/m³	0.0

Sand Information

Proppant Type	Size	lbs	Pumped (lbs)	In Formation (lbs)	In Pipe (lbs)
reg	20/40	44000.0	10560.0	10340.0	220.0

Spearhead	Pad Size	Treatment Start Time:	Treatment Finish Time:	Screenout	Sand Conc. at Perfs (lb/gal)
no	156.2	12:11.2	13:03.3	no	1.2

Job Summary

Breakdown Pressure	Volume to fill hole	Max Pressure	Average Pressure	ISIP	AveragePad Pressure	10 min SIP	Average Rate	Frac Gradient
3117.5	22.1	3407.5	3320.5	1290.5	3117.5	391.5	18.9	1128.0

Time (min)	Treating Pressure Casing		Blender Slurry Rate (m³/min) Start of Stage	Blender Slurry Volume (m³) Per Stage	Blender Slurry Volume (m³) Cum. At End of Stage	Blender Clean Rate (m³/min) Start of Stage	Blender Clean Rate (m³/min) End of Stage	Blender Clean Volume (m³) Per Stage	Blender Clean Volume (m³) Cum. At End of Stage	Blender Proppant Concentration (kgs/m³) Start of Stage	Blender Proppant Concentration (kgs/m³) End of Stage	Blender Proppant Total (kgs) Per Stage	Blender Proppant Total (kgs) Cum. At End of Stage	Breaker Loading per m³ per Stage	Procedure & Remarks
22.50	22.6		4.1	24.8	24.8	4.10	4.10	24.8	24.8						Pad.
25.00	22.6		4.2	10.2	35.0	4.20	4.14	10.2	35.0	0	25	128	128		Start sand ramp.
29.00	23.2		3.6	15.2	50.3	3.55	3.49	15.0	50.0	25	50	563	690		Inc. Conc.
31.50	22.9		3.4	9.0	59.3	3.40	3.40	9.0	59.0	0	0	0	690		Shut sand off
35.50	22.8		3.5	13.7	73.0	3.45	3.40	13.5	72.5	25	50	506	1,196		Start sand ramp.
40.00	23.0		2.8	16.5	89.4	2.72	2.64	16.0	88.5	50	100	1,200	2,396		Inc. Conc.
45.10	23.0		2.0	12.7	102.1	1.89	1.83	12.1	100.6	100	150	1,513	4,800		Shut sand off and flush to perfs.

Time	Treating Pressure		Rate	Slurry Volume (bbl)		Rate (bbl/min)		Clean Volume (bbl)		Concentration		Prop Total (lbs)			
22.5	3233		25.8	156.0	156	25.8	25.8	156.0	156						Pad.
25.0	3233		26.4	64.5	220	26.4	26.0	64.2	220	0.0	0.2	280.5	280.5		Start sand ramp.
29.0	3319		22.6	95.7	316	22.3	22.0	94.3	314	0.2	0.4	1238	1518		Inc. Conc.
31.5	3276		21.4	56.6	373	21.4	21.4	56.6	371	0.0	0.0	0	1518		Shut sand off
35.5	3262		22.0	86.1	459	21.7	21.4	84.9	456	0.2	0.4	1114	2631.75		Start sand ramp.
40.0	3290		17.6	103.5	562	17.1	16.6	100.6	557	0.4	0.8	2640	5271.75		Inc. Conc.
45.1	3290		12.6	79.7	642	11.9	11.5	76.1	633	0.8	1.3	3328	10560		Shut sand off and flush to perfs.

Trican Rep.	Customer Rep.
Ryan Robinson	James Wingo

Figure 19 – p. 3 of 4

TRICAN WELL SERVICE LTD. **Treatment Data Charts**

OCEAN ENERGY
Eagle (Gas) 6-9-30-18 348.8 m - 355.2 m
Liquid CO2 Frac, Down Casing September 19, 2002

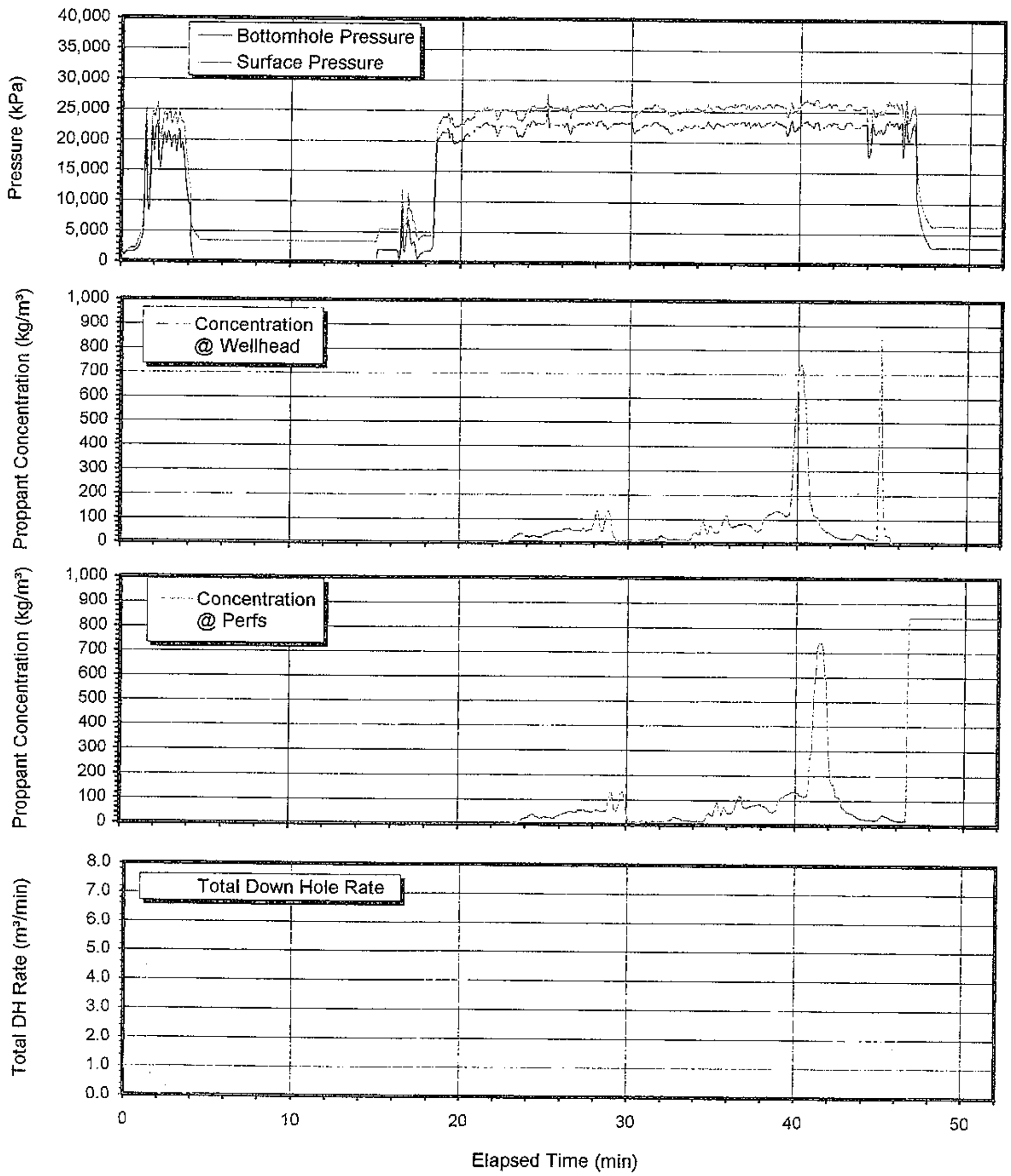


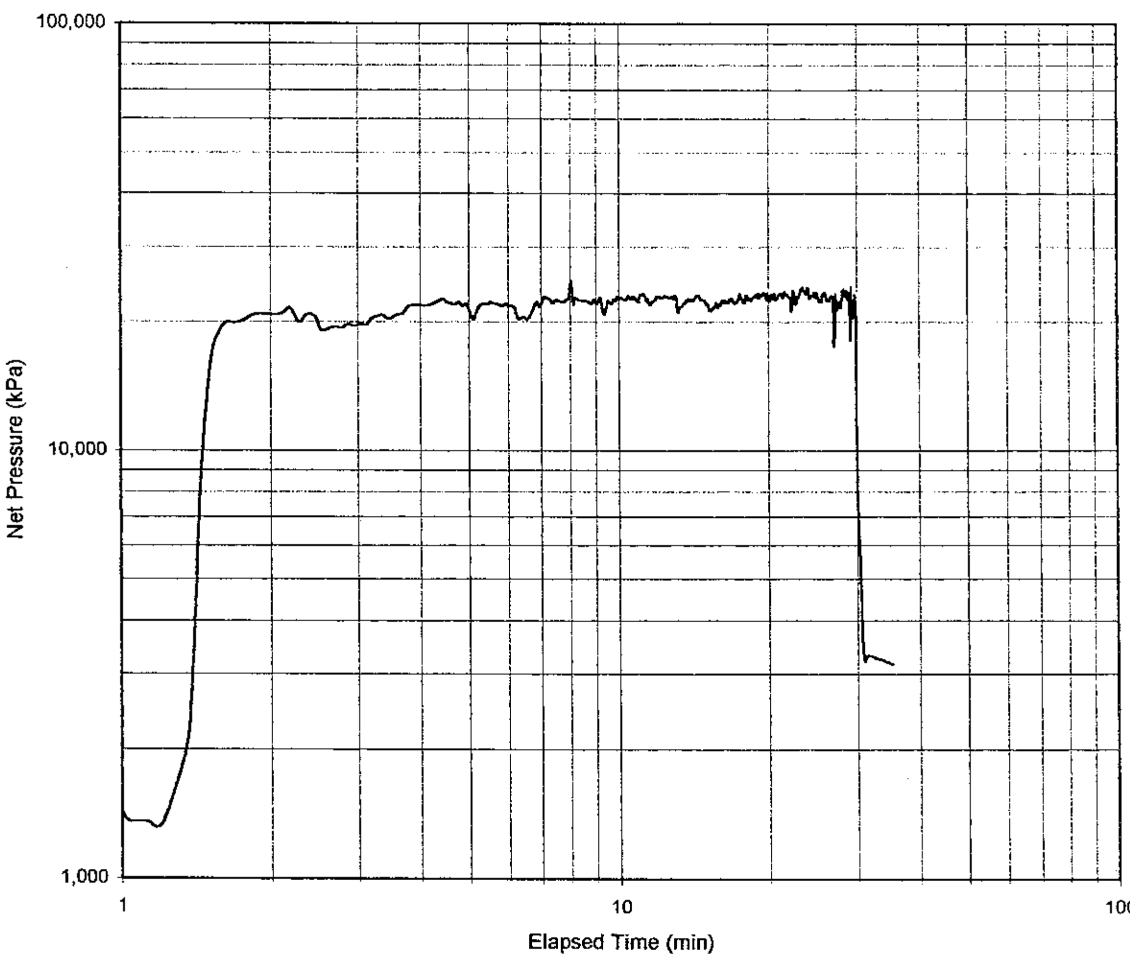
Figure 19 – p. 4 of 4

TRICAN WELL SERVICE LTD.

Net Pressure Chart

(Based On 3,000 kPa Closure)

OCEAN ENERGY
Eagle (Gas) 6-9-30-18 348.8 m - 355.2 m
Liquid CO2 Frac, Down Casing September 19, 2002



5. Stimulation Summary

The stimulation specifics of the four Candidate Wells are summarized:

		CO_2	Sand (lbs)		Max Tr	Avg Rate	Sand Conc	
Well	# - S	Bbls	Pumped	In-Zone	Psi	BPM	Max	Avg
S-B Ranch	02-05	432	10,300	8,500	3,115	37.8	2.4	1.2
Kane	05-08	835	27,300	24,900	3,147	31.0	2.3	1.0
Kane	05-05	815	23,800	21,800	3,495	46.0	2.4	0.9
Blackwood	06-09	633	10,600	10,400	3,408	20.0	1.3	0.6

C. Post Stimulation

1. Flow Back Procedures

The flow back procedure was initiated immediately following the removal of the stimulation hardware. The flow was restricted with a choke to enable the CO_2 vapor to flow safely. The choke size was increased as the pressure diminished and the CO_2 concentration was monitored. Some sand was produced as was expected because of the intentional under flush.

2. Cleaning Frac Sand from the Well Bore

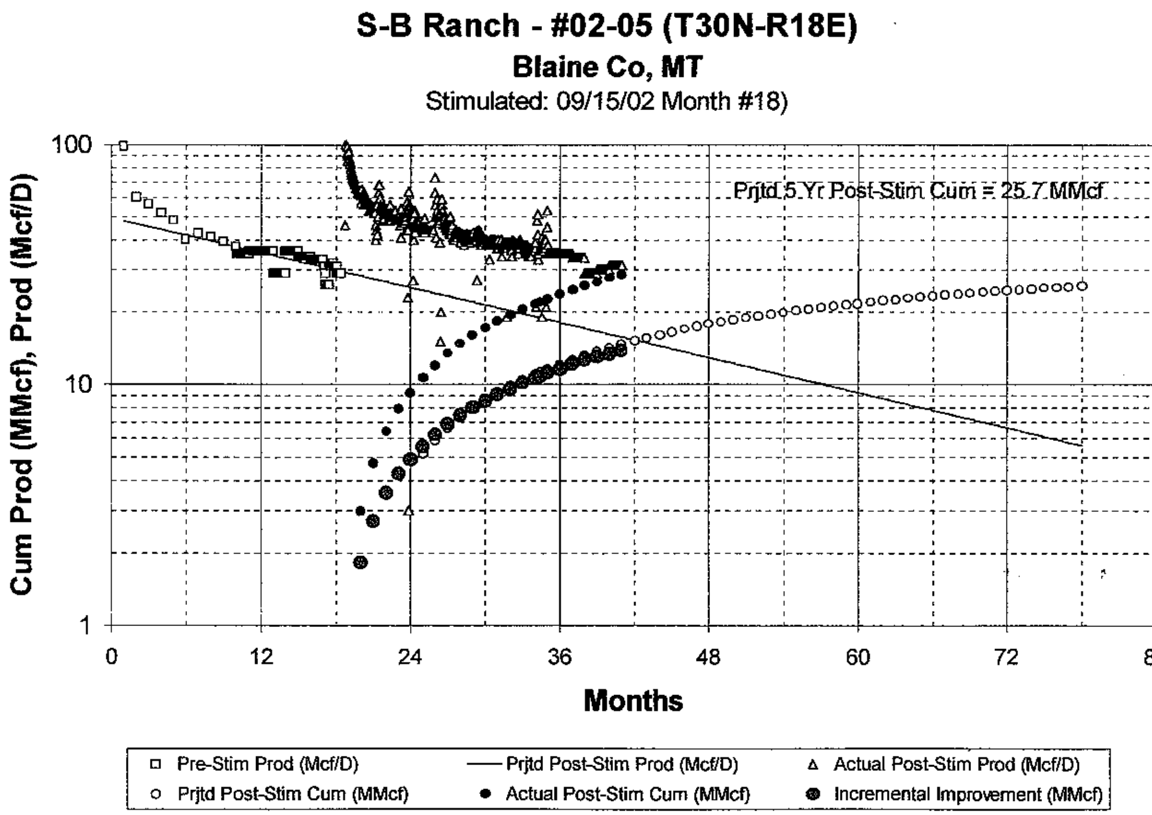
Air was circulated through coiled tubing which was run to the temporary bridge plugs, or in the case of the S-B Ranch 02-05 to the total depth to circulate any sand from the well. In actuality very little was found.

XX. RESULTS

A. Production Comparisons

1. Candidate Well # 1 – S-B Ranch (25-005-22955)

The post-stimulation production through July, 2004 was 28.5 MMcf, and the projected volume based on the pre-stimulation production was 14.7 MMcf, therefore an increase in production volume of 13.8 MMcf has resulted from the liquid-free CO_2 /Sand stimulation.



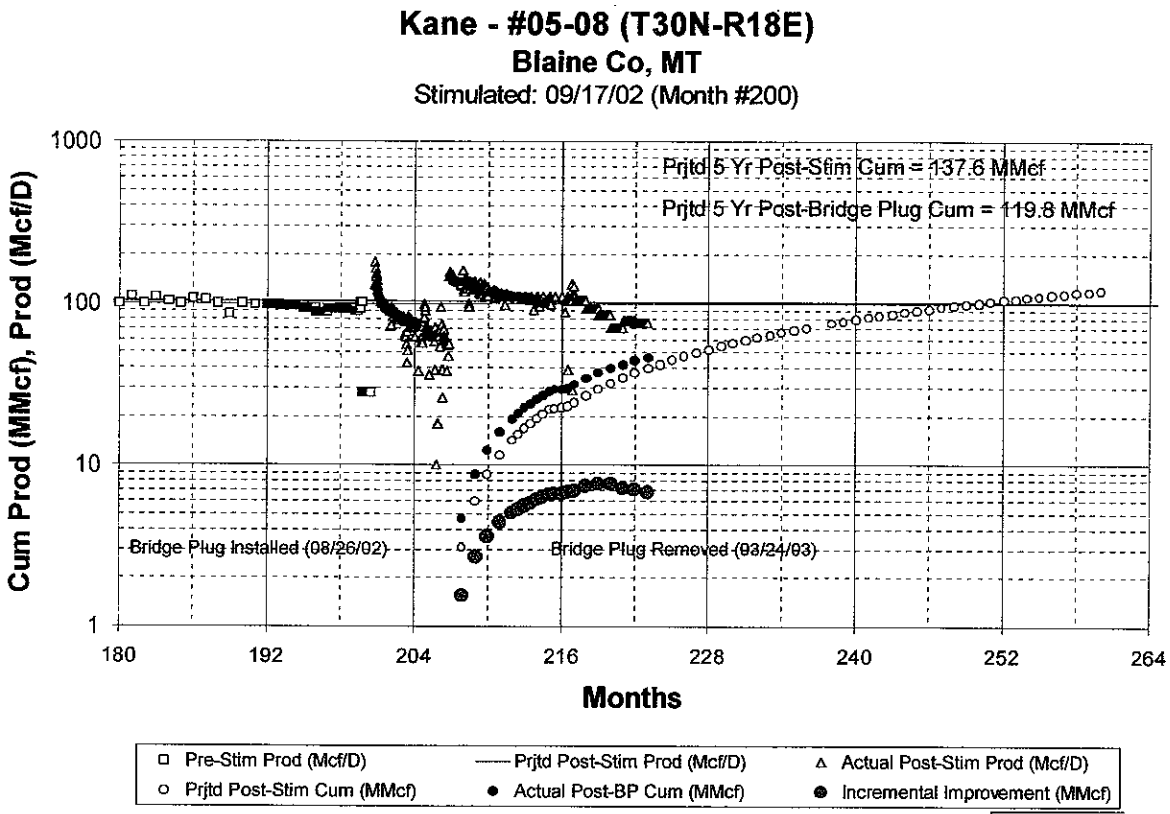
2. Candidate Well # 2 – Kane 05-08 (25-005-22279)

The Kane 05-08 had a bridge plug installed between the Middle and Upper Eagle Sand members during the week of August 26, 2002, was stimulated with the liquid-free CO_2/Sand process on September 17th. The well produced for approximately six months prior to removing the bridge plug on March 24, 2003. When the plug was removed, the production increased from approximately 55 to 150 MCFD confirming that the Upper and Middle Eagle sands were isolated from each other during the stimulation and tests.

The production rates were measured both before (94 MCFD) and after (28 MCFD) the plug was set and the incremental production attributable to the stimulation was recorded for both scenarios.

The post-stimulation production through July, 2004 was 46.4 MMcf. The projected volume based on the pre-stimulation production and adjusted for the non-productive periods was 39.6 MMcf, therefore an increase in production volume of 6.8 MMcf has resulted from the liquid-free CO_2 /Sand stimulation.

There was an additional volume produced from the Upper Eagle following the stimulation and prior to the removal of the Bridge Plug, but it has been excluded to facilitate an objective comparison with the production from both zones prior to the installation of the Bridge Plug.

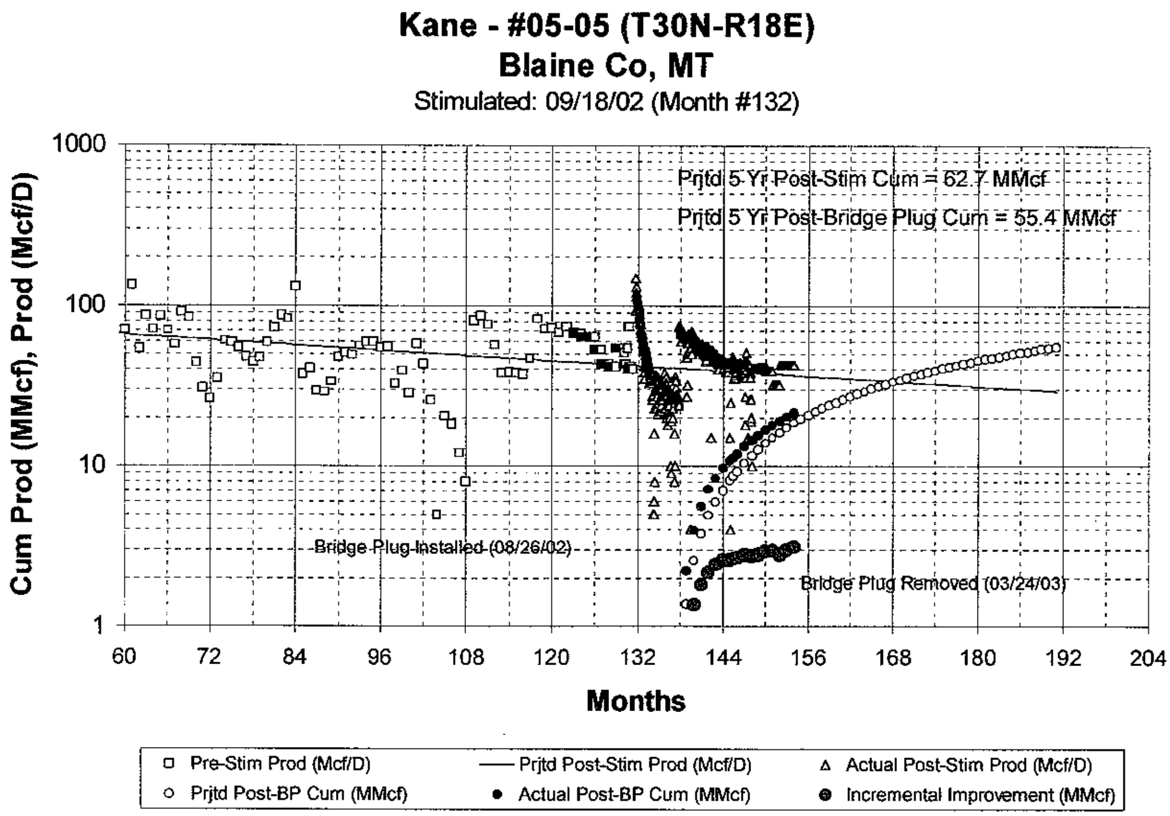

Kane - #05-08 (T30N-R18E)
Blaine Co, MT
Stimulated: 09/17/02 (Month #200)
Prjtd 5 Yr Post-Stim Cum = 137.6 MMcf
Prjtd 5 Yr Post-Bridge Plug Cum = 119.8 MMcf
Bridge Plug Installed (08/26/02)
Bridge Plug Removed (03/24/03)
Cum Prod (MMcf), Prod (Mcf/D)
1000
100
10
1
180
192
204
216
228
240
252
264
Months
Pre-Stim Prod (Mcf/D)
Prjtd Post-Stim Prod (Mcf/D)
Actual Post-Stim Prod (Mcf/D)
Prjtd Post-Stim Cum (MMcf)
Actual Post-BP Cum (MMcf)
Incremental Improvement (MMcf)

3. Candidate Well # 3 – Kane 05-05 (25-005-22557)

The Kane 05-05 had a bridge plug installed between the Middle and Upper Eagle Sand members during the week of August 26, 2002, was stimulated with the liquid-free CO_2/Sand process on September 18th. The well produced for approximately six months prior to removing the bridge plug on March 24, 2003, and when the plug was removed, the production increased from approximately 25 to 75 MCFD establishing that the Upper and Middle Eagle sands were isolated from each other during the stimulation and tests.

The post-stimulation production through July, 2004 was 21.5 MMcf, and the projected volume based on the pre-stimulation production was 18.4 MMcf, therefore an increase in production volume of 3.1 MMcf has resulted from the liquid-free CO_2 /Sand stimulation.

There was an additional volume produced from the Upper Eagle following the stimulation and prior to the removal of the Bridge Plug, but it has been excluded to facilitate an objective comparison with the production from both zones prior to the installation of the Bridge Plug.

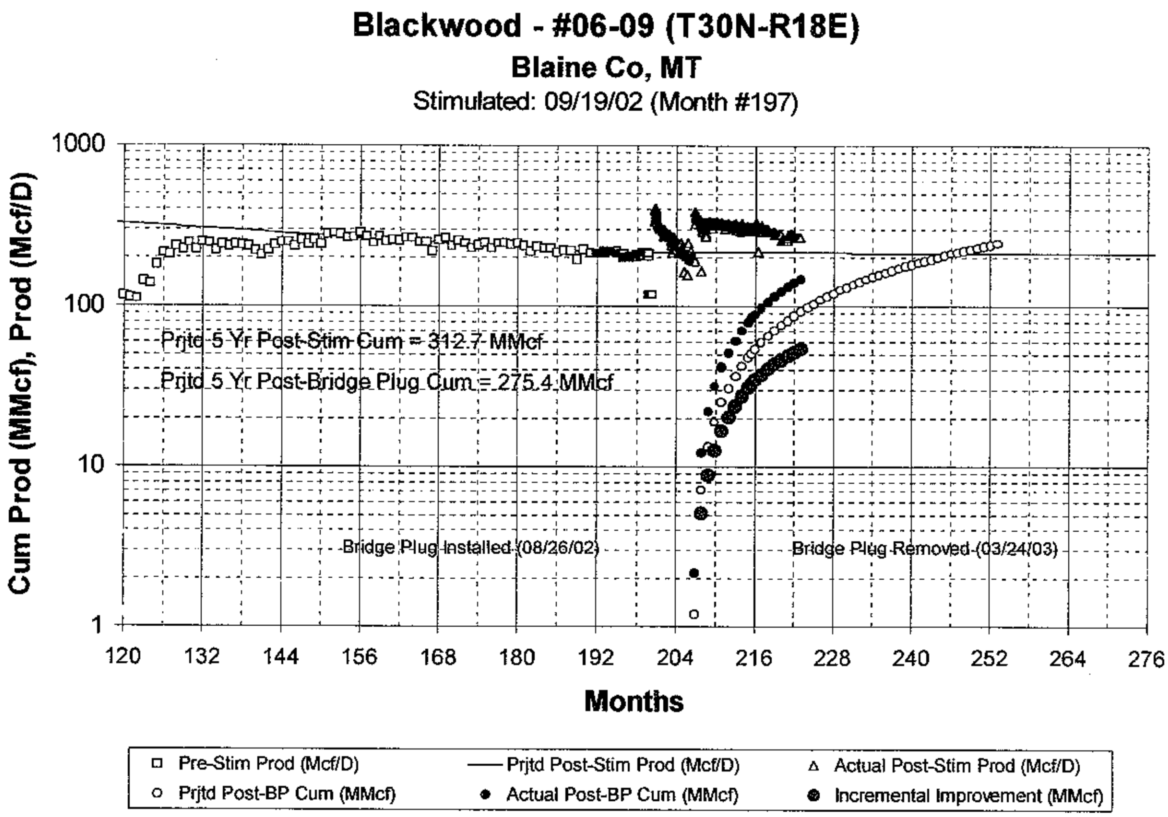

Kane - #05-05 (T30N-R18E)
Blaine Co, MT
Stimulated: 09/18/02 (Month #132)
Cum Prod (MMcf), Prod (Mcf/D)
1000
100
10
1
60
72
84
96
108
120
132
144
156
168
180
192
204
Months
Prjtd 5 Yr Post-Stim Cum = 62.7 MMcf
Prjtd 5 Yr Post-Bridge Plug Cum = 55.4 MMcf
Bridge Plug Installed (08/26/02)
Bridge Plug Removed (03/24/03)
Pre-Stim Prod (Mcf/D)
Prjtd Post-Stim Prod (Mcf/D)
Actual Post-Stim Prod (Mcf/D)
Prjtd Post-BP Cum (MMcf)
Actual Post-BP Cum (MMcf)
Incremental Improvement (MMcf)

4. Candidate Well # 4 - Blackwood 06-09 (25-005-22161)

The Blackwood 06-09 had a bridge plug installed between the Middle and Upper Eagle Sand members during the week of August 26, 2002, was stimulated with the liquid-free CO_2/Sand process on September 19th. The well produced for approximately six months prior to removing the bridge plug on March 24, 2003. When the plug was removed, the production increased from approximately 190 to 370 MCFD establishing that the Upper and Middle Eagle sands were isolated from each other during the stimulation and tests.

The post-stimulation production following the removal of the Bridge plug through July, 2004 was 146.8 MMcf, and the projected volume based on the pre-stimulation production was 92.7 MMcf, therefore an increase in production volume of 54.1 MMcf has resulted from the liquid-free CO_2 /Sand stimulation.

There was an additional volume produced from the Upper Eagle following the stimulation and prior to the removal of the Bridge Plug, but it has been excluded to facilitate an objective comparison with the production from both zones prior to the installation of the Bridge Plug.

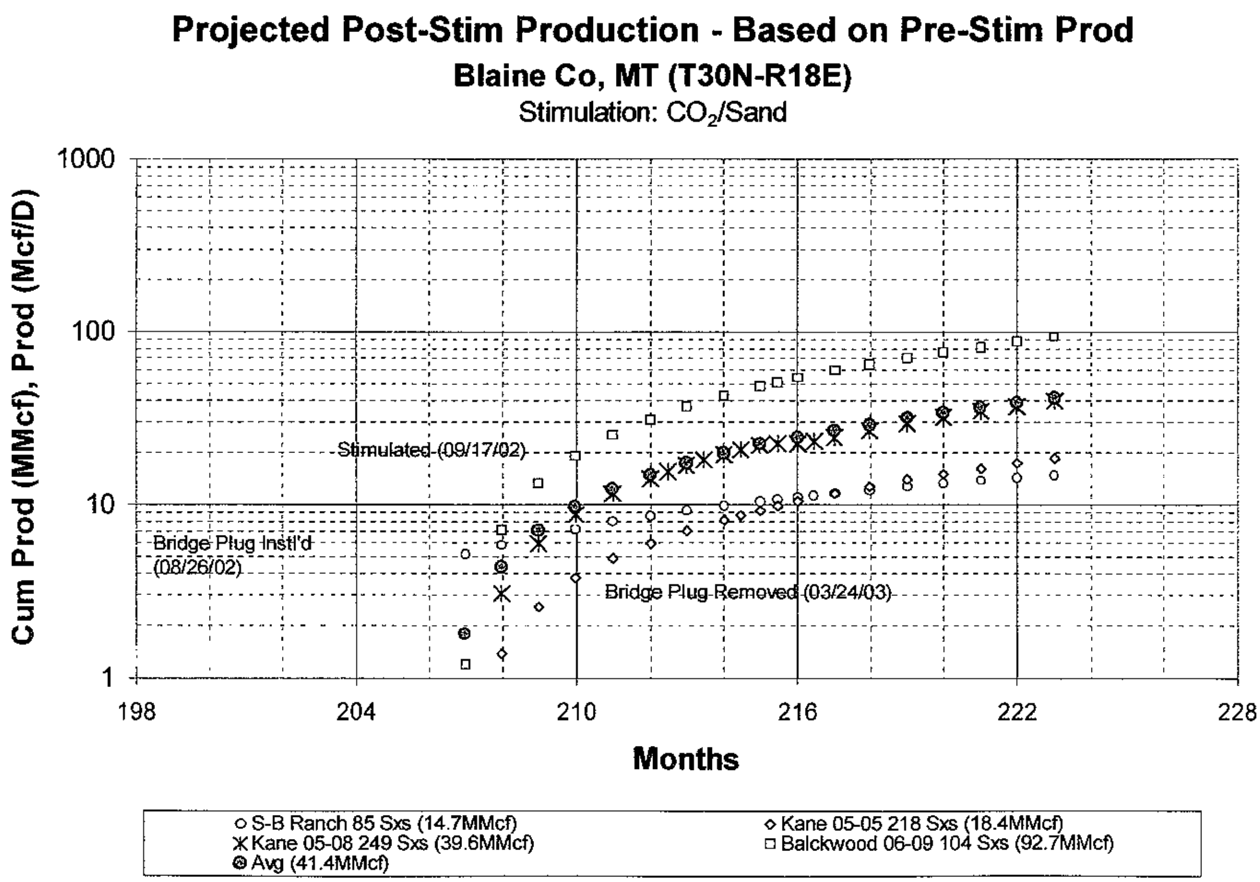

Blackwood - #06-09 (T30N-R18E)
Blaine Co, MT
Stimulated: 09/19/02 (Month #197)
Cum Prod (MMcf), Prod (Mcf/D)
1000
100
10
1
Prjtd 5 Yr Post-Stim Cum = 312.7 MMcf
Prjtd 5 Yr Post-Bridge Plug Cum = 275.4 MMcf
Bridge Plug Installed (08/26/02)
Bridge Plug Removed (03/24/03)
120
132
144
156
168
180
192
204
216
228
240
252
264
276
Months
Pre-Stim Prod (Mcf/D)
Prjtd Post-Stim Prod (Mcf/D)
Actual Post-Stim Prod (Mcf/D)
Prjtd Post-BP Cum (MMcf)
Actual Post-BP Cum (MMcf)
Incremental Improvement (MMcf)

B. Production Summary – Candidate Wells

1. Production Comparisons – Pre and Post Stimulation

a. Pre-Stimulation

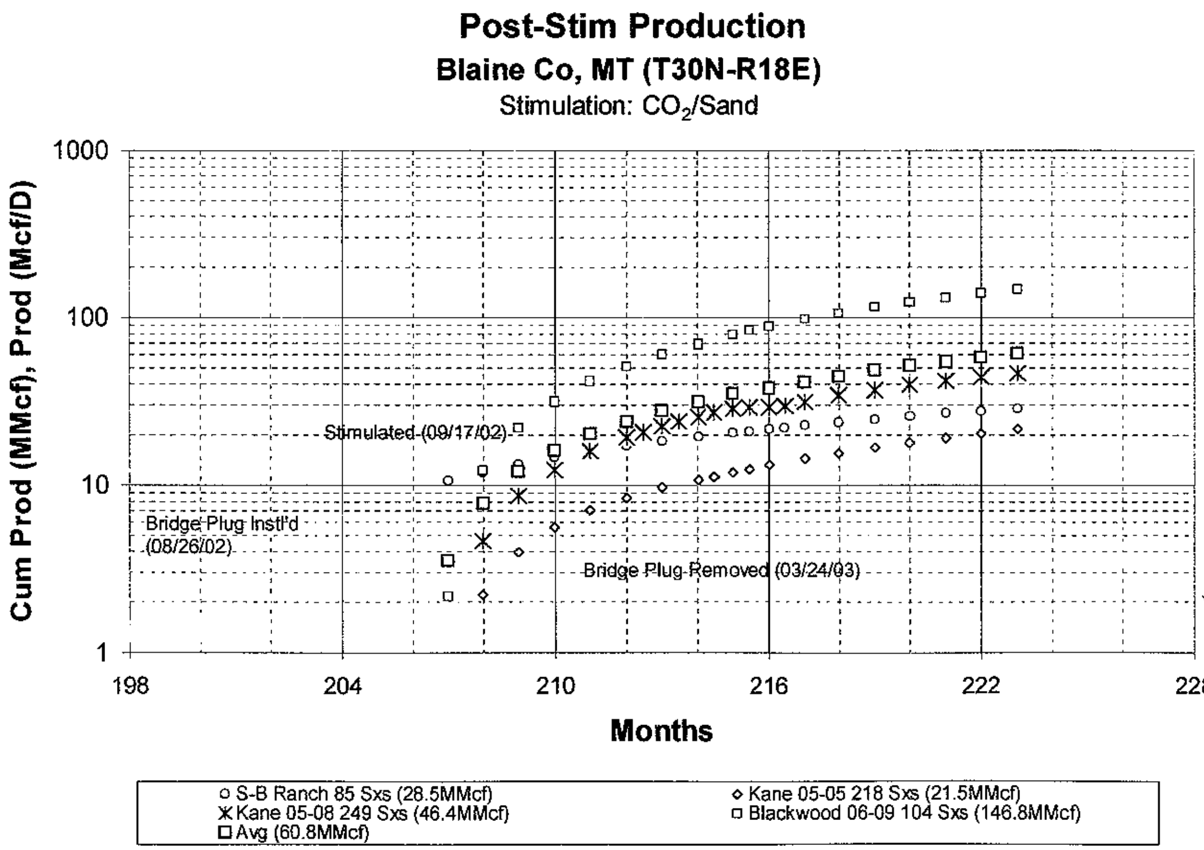
The pre-stimulation production from the four Candidate Wells was extrapolated to project the future production, and these projections served as the basis to which the production following the stimulations was compared. The projected post-stimulation volumes ranged from 14.7 to 92.7 MMcf and averaged 41.4 MMcf through July, 2004.



b. Post-Stimulation

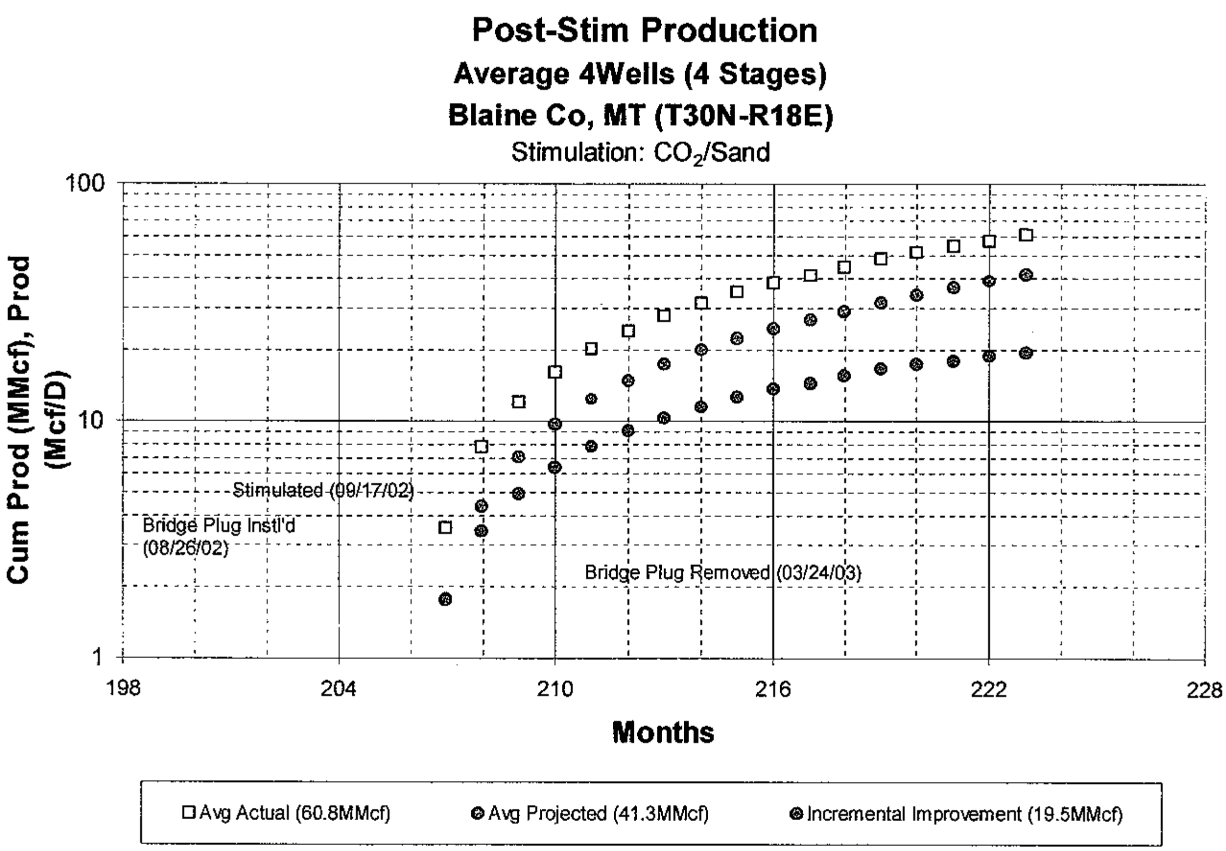
Because Ocean failed to provide the production data as per contract, the production data was obtained from public data sources (through July, 2004). The public data is reported on a monthly basis and does not include the number of producing days and therefore the production comparisons do not take into account any non-production times which results in the incremental improvements being reduced. There were known instances of non-producing periods exceeding two weeks in one of the wells and also other non-producing time intervals for all four Candidates as well.

The post-stimulation volumes for an unknown of producing days ranged from 21.5 to 146.8 MMcf and averaged 60.8 MMcf through July, 2004.



c. Incremental Production Improvement

The incremental production improvements irrespective of the unknown number of producing days mentioned above ranged from 3.1 to 54.1 MMcf and averaged 19.5 MMcf through July, 2004.



Through July 2004

Twp/Rge	T30N/R18E	T30N/R18E	T30N/R18E	T30N/R18E	Totals
Co/St	Blaine/Mt	Blaine/Mt	Blaine/Mt	Blaine/Mt	
Field	Tiger Ridge	Tiger Ridge	Tiger Ridge	Tiger Ridge	
API Number (25-005-xxxxx)	22955	22279	22557	22161	
Surface	S-B Ranch	Kane	Kane	Blackwood	
Sec-#	02-05	05-08	05-05	06-09	
Subsequent to Bridge Plug Removal*					
Actual Post-stim Cum (MMcf)	28.5	46.4	21.5	146.8	243.2
Proj Cum (based on pre-stim prod) MMcf)	14.7	39.6	18.4	92.7	165.4
Incremental Prod Increase (MMcf)	13.8	6.8	3.1	54.1	77.8

XXI. COSTS

A. Projected

The stimulation costs were bid in February, 2002 and included a significant discount – providing that the treatments were executed in April, during the reduced activity period during the spring "break up" – a copy is attached (Figure 20).

Blender, 1770 HHP (1 Quint), manifold and iron truck: 44,100 pounds frac sand (20/40), 685 bbls CO_2 (132 tons), delivery (186 miles), and computer control center and report:	(US) $60,533
3 Wells:	$181,599
Mobilization:	5,665
Presuming that no standby charges are incurred, then the charge for stimulating the three Candidate Wells would be:	$187,264
Or per well:	(US) **$62,421**

The cost-sharing would result in the following per-well allocations:

Ocean	$31,211
DOE	$31,210
Total	$62,421

Figure 20 – p. 1 of 8

TRICAN WELL SERVICE LTD.

STIMULATION PROPOSAL

Liquid CO2 Frac

20.0 tonne Sand (20/40)

Belly River - Eagle (Gas)

Ocean Energy - Hill County   Havre Montana

Version 1   Option 1

Inject Down Casing

Approved: September 27 2001

PETROLEUM CONSULTING SERVICES
Box 35833
Canton, Ohio
44735

Prepared For: Raymond Mazza

For Service Call: Red Deer (403) 346-4667

Sales Rep: Chuck Vozniak (403) 215 1982   **Designed By:** Michael Tulissi (403) 215 2995

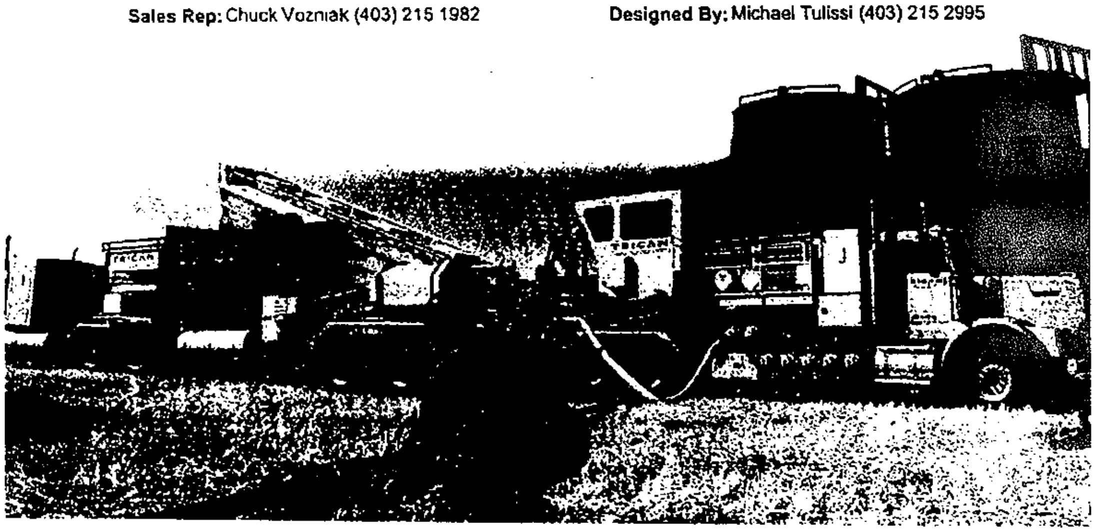
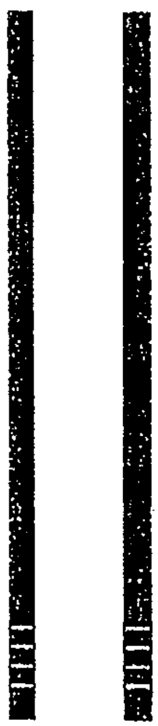


Figure 20 – p. 2 of 8

TRICAN

Ocean Energy - Hill County Havre Montana
Liquid CO2 Frac
Option 1 Version 1

Completions



Wellhead: Casing Saver
Pumping Configuration: Casing

Casing: 114.3mm, 14.14kg/m, J-55 (4.50" 9.50 lb/ft)
0.0 - 480.0 m (TMD) (1575 FT)

Burst: 30 MPa 4351 psi
Collapse: 23 MPa 3336 psi

Hole Volume: 3.87 m^3 136.7 Cu ft = 24.3 bbl

Perforations: 457.0 - 480.0 m (TMD) 1500 1574

Formation: Belly River - Eagle (Gas)
Frac Gradient: 22.0 kPa/m = 0.97 psi/ft
BHST: 14 °C 57 F

Calculations

$P_{fracture}$ = Gradient$_{fracture}$ (22.0 kPa/m) x Depth$_{vertical}$ (480.0 m) = **10560 kPa** 1532 psi
$P_{friction}$ = Gradient$_{friction}$ (12.0 kPa/m) x Depth$_{measured}$ (480.0 m) = **5760 kPa** 835 psi
$P_{hydrostatic}$ = Gradient$_{hydrostatic}$ (10.0 kPa/m) x Depth$_{vertical}$ (480.0 m) = **4800 kPa** 696 psi
$P_{injection}$ = $P_{fracture}$ (10560 kPa) + $P_{friction}$ (5760 kPa) - $P_{hydrostatic}$ (4800 kPa) = **11520 kPa** 1672
Power$_{CO_2}$ = $P_{injection}$ (11520 kPa) x Rate$_{CO_2}$ (7.5 m^3/min) / 60 = **1440 kW** = 1931 hp

Figure 20 – p. 3 of 8

TRICAN

Ocean Energy - Hill County Havre Montana
Liquid CO2 Frac
Option 1 Version 1

Procedures

Equipment: 2 CO2 Storage Tanks
2 CO2 Transports
1440 kW Frac CO2 Pumping
1 Frac Van
1 Iron Truck
1 Liquid CO2 Blender
2 N2 Pumping Units

Objective: To perform a CO2 Frac treatment on the Eagle (Belly River) formation.

Key Notes: Be prepared to flow well back immediately following treatment.

Safety: Spot tanks and equipment as per recommended equipment spacing. Conduct pre-treatment safety meeting with all personnel on location. Review all fire, chemical, and high pressure hazards.

Rig Up: Rig up to fracture well down Casing, through a Casing Saver.

Pressure: Pressure Test: 30 MPa × 0.145 = 4350 psi
Maximum Pressure: 24 MPa = 3480

Rate: Anticipated downhole rate is 7.50 m³/min. at 11,520 kPa. = 1670 psi

Spearhead: 1.00 m³ of Spearhead Acid. × 6.2905 = 6.2905 BBL × 42 = 264 gal

Pad: 50.00 m³ of CO2. × 1.21 = 60.5 T = 1766 ft³ = 31488 L
44,100 lb 32588 L (62.6 T)

Proppant: 20.00 tonne of Sand (20/40), placed with 51.70 m³ of CO2.
14.3 BBL 5.0

Flush: 3.07 m³ of CO2. This corresponds to an underflush volume of 0.80 m³, and must be recalculated on location.

Shut In: Shut in well, and rig out Trican equipment. Customer will supply all flowback equipment. When flowing well back, follow Alberta Recommended Practices, OHS, & AEUB recommendations.

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Ocean Energy - Hill County Havre Montana
Liquid CO2 Frac
Option 1 Version 1

Fluid And Mixing Requirements

HCl (15%) Volume From Program: 1.0 m³
Additional Fluid Volume: 0.0 m³
Total HCl (15%) Volume: 1.0 m³ 264 gal

CO2 (Liquid) Volume From Program: 104.77 m³ × 6.29 = 659 BBL × 1/5.9 = 127 T
Cool-down and Losses: 27.23 m³ 171 / 830 33 T / 160
Total CO2 (Liquid) Volume: 132.0 m³ Requires: 2 CO2 Transports
2 CO2 Storage Tanks

N2 Volume From Program: 4000 sm³ × 35.31 = 141,200 scf
Cool-down and Losses: 600 sm³ 21,186 / 162,386
Total N2 Volume: 4600 sm³ Requires: 2 N2 Pumping Units

1 m³ Spearhead Acid (15% HCl) Spearhead
5 kg/m³ IC-3 (Iron Control) - pre-mixed
2 L/m³ AI-1 (Corrosion Inhibitor) - pre-mixed
2 L/m³ S-1 (Surfactant) - pre-mixed

Total Products Required

2 L AI-1 (Corrosion Inhibitor)
1 m³ HCl (15%)
4600 sm³ N2 (Gas)
20 tonne Sand (20/40)
132 m³ CO2 (Liquid) 160 T
5 kg IC-3 (Iron Control)
2 L S-1 (Surfactant)

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Ocean Energy - Hill County Havre Montana
Liquid CO2 Frac
Option 1 Version 1

Treatment Schedules

Liquid CO_2 Blender Treatment Schedule1

Stage	Blender Slurry Rate (m^3/min)	Blender Slurry Volume (m^3)		Blender Clean Rate (m^3/min)		Blender Clean Volume (m^3)		Blender Proppant Concentration (kg / m^3)		Blender Proppant Amount (tonne)		Fluid And Proppant	
	Start of Stage	Per Stage	Cum. At End Of Stage	Start of Stage	End of Stage	Per Stage	Cum. At End Of Stage	Start of Stage	End of Stage	Per Stage	Cum. At End Of Stage		
1 Spearhead	1.00 63	1.0 63	0.0	1.00	1.00	1.0	0.0					Spearhead Acid	
2 Pad	7.50 47.2	50.0	50.0	7.50	7.50	50.0	50.0					CO2	
3 Proppant	7.50	14.5 3.1	53.1	7.36	7.23	3.0	53.0	0.42 50	100	4.4 0.2	4.4 0.2	CO2 Sand (20/40)	1
4 Proppant	7.50	26.6 6.3	59.4	7.23	6.97	6.0	59.0	0.83 100	200	0.9	24 1.1	CO2 Sand (20/40)	5
5 Proppant	7.50	41.5 6.6	66.0	6.97	6.74	6.0	65.0	1.67 200	300	1.5	57 2.6	CO2 Sand (20/40)	13
6 Proppant	7.50	64 10.2	76.2	6.74	6.52	9.0	74.0	2.50 300	400	3.2	128 5.8	CO2 Sand (20/40)	29
7 Proppant	7.50	88.1 14.0	90.2	6.52	6.31	12.0	86.0	3.34 400	500	5.4	247 11.2	CO2 Sand (20/40)	56
8 Proppant	7.50	88.1 14.5	104.7	6.31	6.12	12.0	98.0	4.17 500	600	6.6	391 17.8	CO2 Sand (20/40)	89
9 Proppant	7.50	28.3 4.5	109.3	6.12	6.12	3.7	101.7	5.01 600	600	2.2	441 20.0	CO2 Sand (20/40)	100
10 Flush	7.50	19.5 3.1	112.3	7.50	7.50	3.1	104.8					CO2	

706.4

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Ocean Energy - Hill County Havre Montana
Liquid CO2 Frac
Option 1 Version 1

Discounted Price

Amount	Description	Discount	Unit Price (Discounted, Area A)	Price (Discounted)	#US × 1/1.5
Services And Equipment					
2 unit	CO2 Storage Tank	25.0%	$1,830.00 / unit	$3,660.00	2331
2 unit	CO2 Transport (Setup)	25.0%	$465.00 / unit	$930.00	592
1074 hp 1440 kW	Frac CO2 Pumping (kW, 0-35.0 MPa)	25.0%	$9.23 / kW	$13,284.00	11825
1 unit	Frac Van (Setup)	25.0%	$2,895.00 / unit	$2,895.00	1844
1 unit	Iron Truck (Setup)	25.0%	$1,132.50 / unit	$1,132.50	721
1 unit	Liquid CO2 Blender (Setup)	25.0%	$1,642.50 / unit	$1,642.50	1046
2 unit	N2 Pumping Unit (Setup)	25.0%	$1,687.50 / unit	$3,375.00	2150
47.2 bPM 7.5 m³/min	Blender (Pumping)	25.0%	$157.50 / m³/min	$1,181.25	752
				Sub-total: $28,100.25	21,261
Products					
2 L	AI-1 (Corrosion Inhibitor)	25.0%	$19.39 / L	$38.78	
160T 830 bbL 132 m³	CO2 (Liquid) 466.54 /T	25.0%	$565.50 / m³	$74,646.00	35,657
1 m³	HCl (15%)	25.0%	$435.00 / m³	$435.00	
5 kg	IC-3 (Iron Control)	25.0%	$9.26 / kg	$46.31	
162.4 MCF 4600 sm³	N2 (Gas) 28.68 /MCF	25.0%	$1.01 / sm³	$4,657.50	1340
2 L	S-1 (Surfactant)	25.0%	$15.00 / L	$30.00	
44,100 # 20 tonne	Sand (20/40) 12.92 /sk	25.0%	$285.00 / tonne	$5,698.58	3630
				Sub-total: $85,552.16	40,629
Travel And Cartage					
20 tonne x 300 km	Cartage (Proppant) (44,100 lb / 2000 lb/T)(186.4 mi) = 4110 T·mi	25.0%	$0.71 / tonne km	$4,275.00	2723
160T 132 m³ x 300 km	Cartage (Liquid CO2) # 72.39 /T	25.0%	$0.29 / m³ km	$11,583.00	5533
8 unit x 300 km	Frac Unit (Travel) 1086 / unit	25.0%	2.25 /mi $3.62 / unit km	$8,694.00	5538
2 unit x 300 km	N2 Unit (Travel)	25.0%	$3.62 / unit km	$2,173.50	1384
1 unit x 300 km	Acid Unit (Travel)	25.0%	$3.62 / unit km	$1,086.75	-
				Sub-total: $27,812.25	

Total Discounted Price: $141,464.66

All quantities (including mileage) are estimated, and are subject to change depending upon actual amounts used. Any service or materials required, but not mentioned will be at book price less discount. Any applicable taxes (eg: GST) will be added to the invoice. Book prices less discount are in effect for 30 days after the date shown. **Due to the uncertainty of energy costs, prices may change without notice.**

Third Party

	Wellhead Saver (Casing)
	Fluid Cartage & Heating

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TRICAN

Ocean Energy - Hill County Havre Montana
Liquid CO2 Frac
Option 1 Version 1

Discounted Price

Amount	Description	Discount	Unit Price (Discounted, Area A)	Price (Discounted)
Services And Equipment				
2 unit	CO2 Storage Tank	25.0%	$1,830.00 / unit	$3,660.00
2 unit	CO2 Transport (Setup)	25.0%	$465.00 / unit	$930.00
1440 kW	Frac CO2 Pumping (kW, 0-35.0 MPa)	25.0%	$9.23 / kW	$13,284.00
1 unit	Frac Van (Setup)	25.0%	$2,895.00 / unit	$2,895.00
1 unit	Iron Truck (Setup)	25.0%	$1,132.50 / unit	$1,132.50
1 unit	Liquid CO2 Blender (Setup)	25.0%	$1,642.50 / unit	$1,642.50
2 unit	N2 Pumping Unit (Setup)	25.0%	$1,687.50 / unit	$3,375.00
7.5 m³/min	Blender (Pumping)	25.0%	$157.50 / m³/min	$1,181.25
				Sub-total: $28,100.25
Products				
2 L	AI-1 (Corrosion Inhibitor)	25.0%	$19.39 / L	$38.78
132 m³	CO2 (Liquid)	25.0%	$565.50 / m³	$74,646.00
1 m³	HCl (15%)	25.0%	$435.00 / m³	$435.00
5 kg	IC-3 (Iron Control)	25.0%	$9.26 / kg	$46.31
4600 sm³	N2 (Gas)	25.0%	$1.01 / sm³	$4,657.50
2 L	S-1 (Surfactant)	25.0%	$15.00 / L	$30.00
20 tonne	Sand (20/40)	25.0%	$285.00 / tonne	$5,698.58
				Sub-total: $85,552.16
Travel And Cartage				
20 tonne x 300 km	Cartage (Proppant)	25.0%	$0.71 / tonne km	$4,275.00
132 m³ x 300 km	Cartage (Liquid CO2)	25.0%	$0.29 / m³ km	$11,583.00
8 unit x 300 km	Frac Unit (Travel)	25.0%	$3.62 / unit km	$8,694.00
2 unit x 300 km	N2 Unit (Travel)	25.0%	$3.62 / unit km	$2,173.50
1 unit x 300 km	Acid Unit (Travel)	25.0%	$3.62 / unit km	$1,086.75
				Sub-total: $27,812.25

Total Discounted Price: $141,464.66

All quantities (including mileage) are estimated, and are subject to change depending upon actual amounts used. Any service or materials required, but not mentioned will be at book price less discount. Any applicable taxes (eg: GST) will be added to the invoice. Book prices less discount are in effect for 30 days after the date shown. **Due to the uncertainty of energy costs, prices may change without notice.**

Third Party

	Wellhead Saver (Casing) Fluid Cartage & Heating

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Ocean Energy - Hill County Havre Montana
Liquid CO2 Frac
Option 1 Version 1

Treatment Schedules

Liquid CO_2 Blender Treatment Schedule1

Stage	Blender Slurry: Rate (m^3/min) Start of Stage	Blender Slurry: Volume (m^3) Per Stage	Blender Slurry: Volume (m^3) Cum. At End Of Stage	Blender Clean: Rate (m^3/min) Start of Stage	Blender Clean: Rate (m^3/min) End of Stage	Blender Clean: Volume (m^3) Per Stage	Blender Clean: Volume (m^3) Cum. At End Of Stage	Blender Proppant: Concentration (kg / m^3) Start of Stage	Blender Proppant: Concentration (kg / m^3) End of Stage	Blender Proppant: Amount (tonne) Per Stage	Blender Proppant: Amount (tonne) Cum. At End Of Stage	Fluid And Proppant
1 Spearhead	1.00	1.0	0 0	1.00	1.00	1.0	0.0					Spearhead Acid
2 Pad	7.50	50.0	50.0	7.50	7.50	50.0	50.0					CO2
3 Proppant	7.50	3.1	53.1	7.36	7.23	3.0	53.0	50	100	0.2	0.2	CO2 Sand (20/40)
4 Proppant	7.50	6.3	59.4	7.23	6.97	6.0	59.0	100	200	0.9	1.1	CO2 Sand (20/40)
5 Proppant	7.50	6 6	66.0	6.97	6.74	6.0	65.0	200	300	1.5	2.6	CO2 Sand (20/40)
6 Proppant	7.50	10.2	76.2	6.74	6.52	9.0	74.0	300	400	3.2	5.8	CO2 Sand (20/40)
7 Proppant	7.50	14.0	90.2	6.52	6.31	12.0	86.0	400	500	5.4	11.2	CO2 Sand (20/40)
8 Proppant	7 50	14.5	104.7	6.31	6.12	12.0	98.0	500	600	6.6	17.8	CO2 Sand (20/40)
9 Proppant	7.50	4 5	109.3	6.12	6.12	3.7	101.7	600	600	2.2	20.0	CO2 Sand (20/40)
10 Flush	7.50	3.1	112.3	7.50	7.50	3.1	104.8					CO2

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Ocean Energy - Hill County Havre Montana
Liquid CO2 Frac
Option 1 Version 1

Fluid And Mixing Requirements

HCl (15%) Volume From Program: 1.0 m^3
Additional Fluid Volume: 0.0 m^3
Total HCl (15%) Volume: 1.0 m^3

CO2 (Liquid) Volume From Program: 104.77 m^3
Cool-down and Losses: 27.23 m^3
Total CO2 (Liquid) Volume: 132.0 m^3 Requires: 2 CO2 Transports
2 CO2 Storage Tanks

N2 Volume From Program: 4000 sm^3
Cool-down and Losses: 600 sm^3
Total N2 Volume: 4600 sm^3 Requires: 2 N2 Pumping Units

1 m^3 Spearhead Acid (15% HCl) Spearhead
5 kg/m^3 IC-3 (Iron Control) - pre-mixed
2 L/m^3 AI-1 (Corrosion Inhibitor) - pre-mixed
2 L/m^3 S-1 (Surfactant) - pre-mixed

Total Products Required

2 L AI-1 (Corrosion Inhibitor)
1 m^3 HCl (15%)
4600 sm^3 N2 (Gas)
20 tonne Sand (20/40)
132 m^3 CO2 (Liquid)
5 kg IC-3 (Iron Control)
2 L S-1 (Surfactant)

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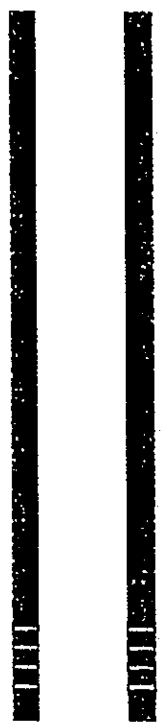
Ocean Energy - Hill County Havre Montana
Liquid CO2 Frac
Option 1 Version 1

Completions



Wellhead: Casing Saver
Pumping Configuration: Casing

Casing: 114.3mm, 14.14kg/m, J-55
0.0 - 480.0 m (TMD)

Burst: 30 MPa
Collapse: 23 MPa

Hole Volume: 3.87 m^3

Perforations: 457.0 - 480.0 m (TMD)

Formation: Belly River - Eagle (Gas)
Frac Gradient: 22.0 kPa/m
BHST: 14 °C

Calculations

$P_{fracture}$ = $Gradient_{fracture}$ (22.0 kPa/m) x $Depth_{vertical}$ (480.0 m) = **10560 kPa**
$P_{friction}$ = $Gradient_{friction}$ (12.0 kPa/m) x $Depth_{measured}$ (480.0 m) = **5760 kPa**
$P_{hydrostatic}$ = $Gradient_{hydrostatic}$ (10.0 kPa/m) x $Depth_{vertical}$ (480.0 m) = **4800 kPa**
$P_{injection}$ = $P_{fracture}$ (10560 kPa) + $P_{friction}$ (5760 kPa) - $P_{hydrostatic}$ (4800 kPa) = **11520 kPa**
$Power_{CO_2}$ = $P_{injection}$ (11520 kPa) x $Rate_{CO_2}$ (7.5 m^3/min) / 60 = **1440 kW**

B. Actual

The actual costs for stimulating the four Candidate Wells ranged from $US 51,065 to 70,113 and averaged $63,189

Invoice	Well	$ Can	Exchange Rate	$ US
C38873	S-B Ranch 02-05-30-18	$ 80,595.69	0.6336	$ 51,065.43
C38874	Kane 05-08-30-18	$104,486.34	0.6336	$ 66,202.55
C38876	Kane 05-05-30-18	$110,657.64	0.6336	$ 70,112.68
C38877	Blackwood 06-09-30-18	$103,183.50	0.6336	$ 65,377.07
Total		$398,923.17		$252,757.73
			Per Well	**63,189**

C. Projected vs. Actual

The actual and projected costs for stimulating the four Candidate Wells were similar:

Actual Cost ($US)	63,189
Projected Cost ($US)	62,421
Difference ($US)	768
Percent (%)	1.2

XXII. CONCLUSIONS

The production through July 2004 (22 months) results in the following observations:

A. CO_2/Sand stimulations can be successfully pumped in the Eagle Sands.

One well, S-B 02-05 screened out with 8,500 lbs of 20/40 sand proppant in zone. The total pumped CO_2 volume was 432 Bbls. Subsequently the pad volume was increased and the wells were treated with available CO_2 volumes.

B. The in-zone placement of proppant was proportional to the pumped CO_2 volume:

		CO2	Sand (lbs)		Sand Conc	
Well	# - S	Bbls	Pumped	In-Zone	Max	Avg
S-B Ranch	02-05	432	10,300	8,500	2.4	1.2
Kane	05-08	835	27,300	24,900	2.3	1.0
Kane	05-05	815	23,800	21,800	2.4	0.9
Blackwood	06-09	633	10,600	10,400	1.3	0.6

C. All four Candidate Wells had production improvements which through July, 2004 (22 months following the stimulation) ranged from 3.1 to 54.1 MMcf and averaged 19.5 MMcf. The total incremental improvement is 77.8 MMcf.

Twp/Rge	T30N/R18E	T30N/R18E	T30N/R18E	T30N/R18E	Totals
Co/St	Blaine/Mt	Blaine/Mt	Blaine/Mt	Blaine/Mt	
Field	Tiger Ridge	Tiger Ridge	Tiger Ridge	Tiger Ridge	
Surface	S-B Ranch	Kane	Kane	Blackwood	Total
Sec-#	02-05	05-08	05-05	06-09	
Subsequent to Bridge Plug Removal*					
Actual Post-stim Cum (MMcf)	28.5	46.4	21.5	146.8	243.2
Proj Cum (based on pre-stim prod) (MMcf)	14.7	39.6	18.4	92.7	165.4
Incremental Prod Increase (MMcf)	13.8	6.8	3.1	54.1	77.8

D. One well, Blackwood 06-09, accounts for the majority – 70% (54.1/77.8) of the incremental production increase.

E. When compared with the criteria for success only one of the four Candidate Wells, Blackwood 06-09 exceeded the production criteria.

Surface	S-B Ranch	Kane	Kane	Blackwood	Total
Sec-#	02-05	05-08	05-05	06-09	
Yr 1					
Production (MMcf)	17.7	35.4	16.3	103.4	172.8
Success Criteria (MMcf)	25.2	47.6	33.1	90.4	196.3
Difference (MMcf)	-7.5	-12.2	-16.8	13.0	-23.5
Yr 1 + 10 Months (Through July 2004)					
Production (MMcf)	28.5	61.0	28.8	194.2	312.5
Success Criteria (MMcf)	43.1	83.0	53.5	161.7	341.3
Difference (MMcf)	-14.6	-22.0	-24.7	32.5	-28.8