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

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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

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.

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.

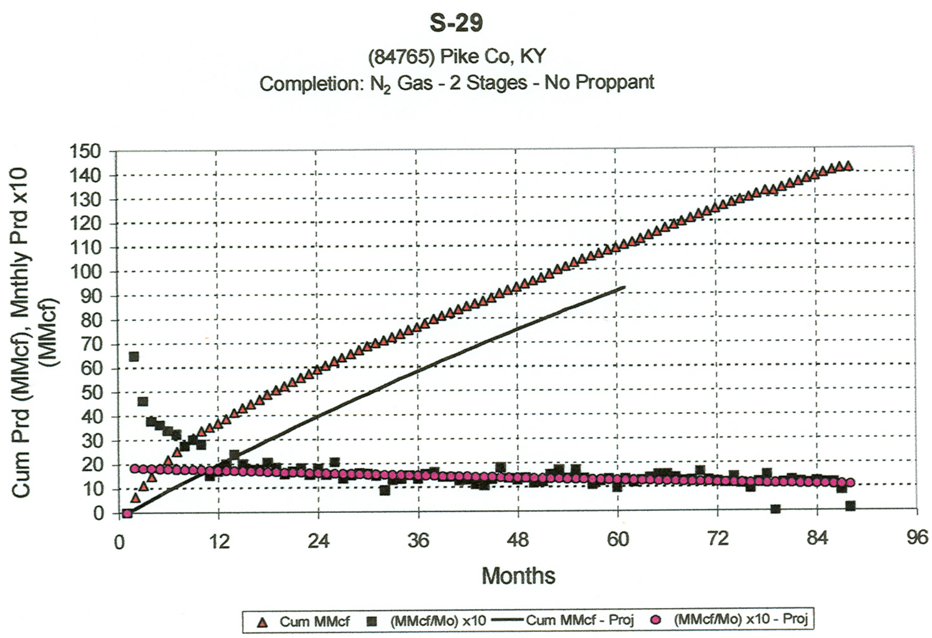
There were some instances where the flush production volumes were minimal which reinforces the benefit of being able to more acutely focus in on the reservoir characteristics through the elimination of this bias. This process can also provide a significant benefit when there is missing production data.

C. Missing Data

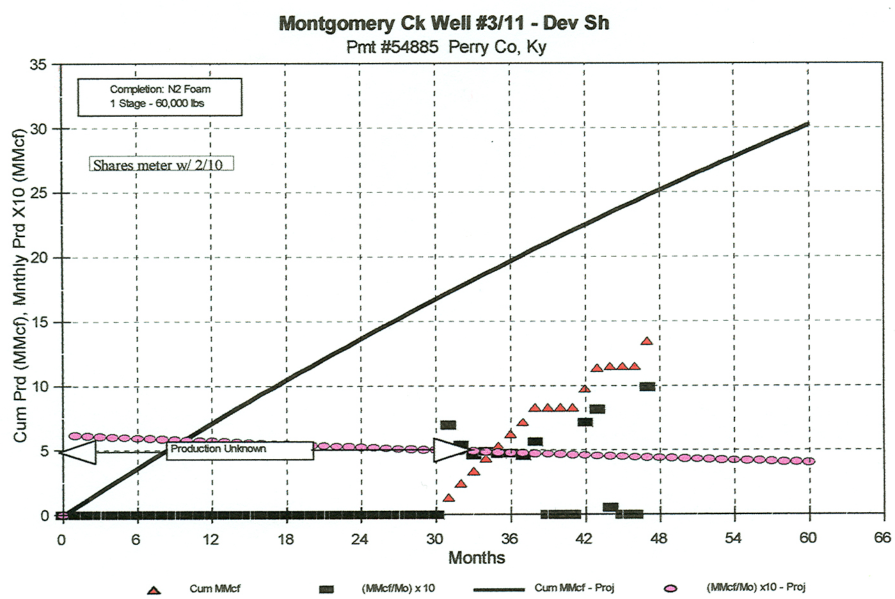
This process can also provide a significant benefit when there is missing production data.

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

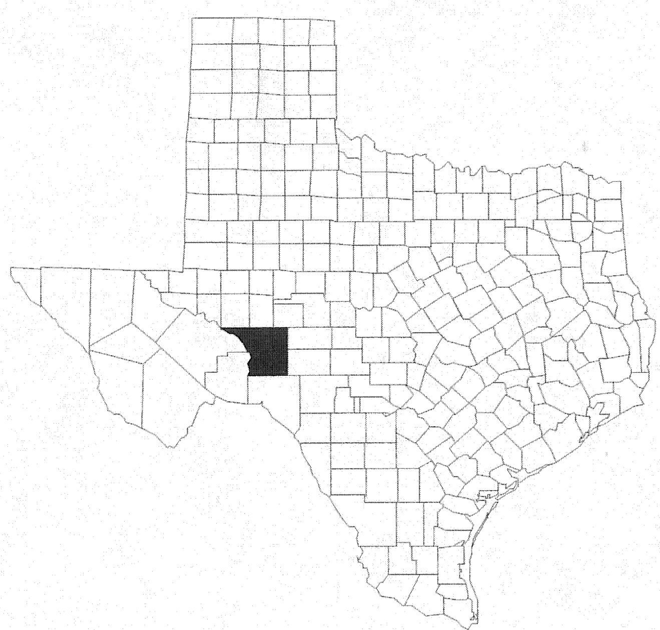
A. TEST AREA #1 – Crockett Co, Tx – Package #'s 1A & 1B - 9 Stages / 6 Wells

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

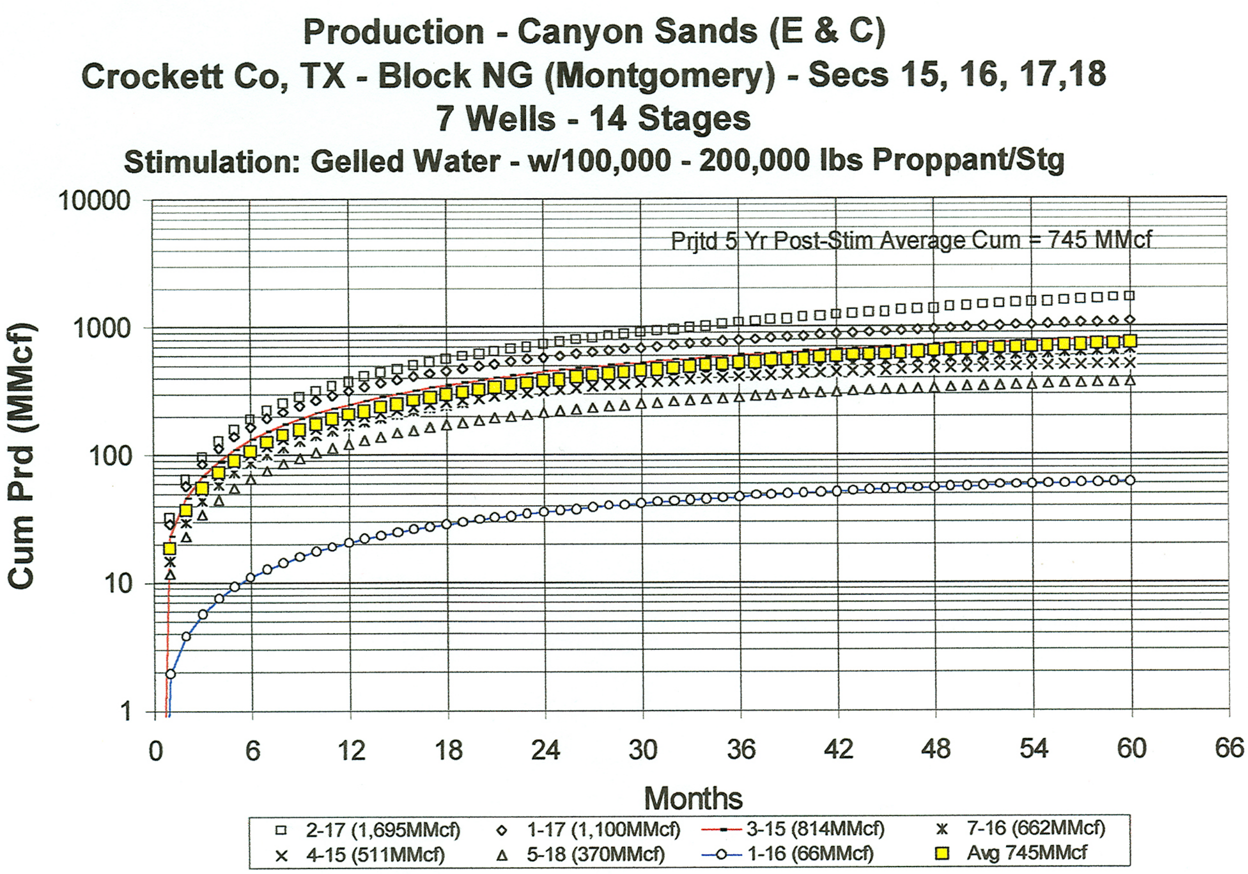
Summary							
		Sand (sacks)		Max Tr Press	Avg Rate	Sand Conc	
Well	St	Pumped	In-Zone	(psi)	(BPM)	Max	Avg
M#13	1	265	242	6,200	47.0	3.0	2.0
M#13	2	261	208	5,796	40.0	3.0	1.5
M#12	1	250	104	6,500	40.0	2.0	1.4
M#12	2	207	198	6,100	43.0	2.0	1.6
M#14	1	115	81	5,590	39.6	2.0	0.9
M#14	2	137	129	5,600	43.0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

f. Results

(1) Production Comparisons

(a) Summary – Control Wells

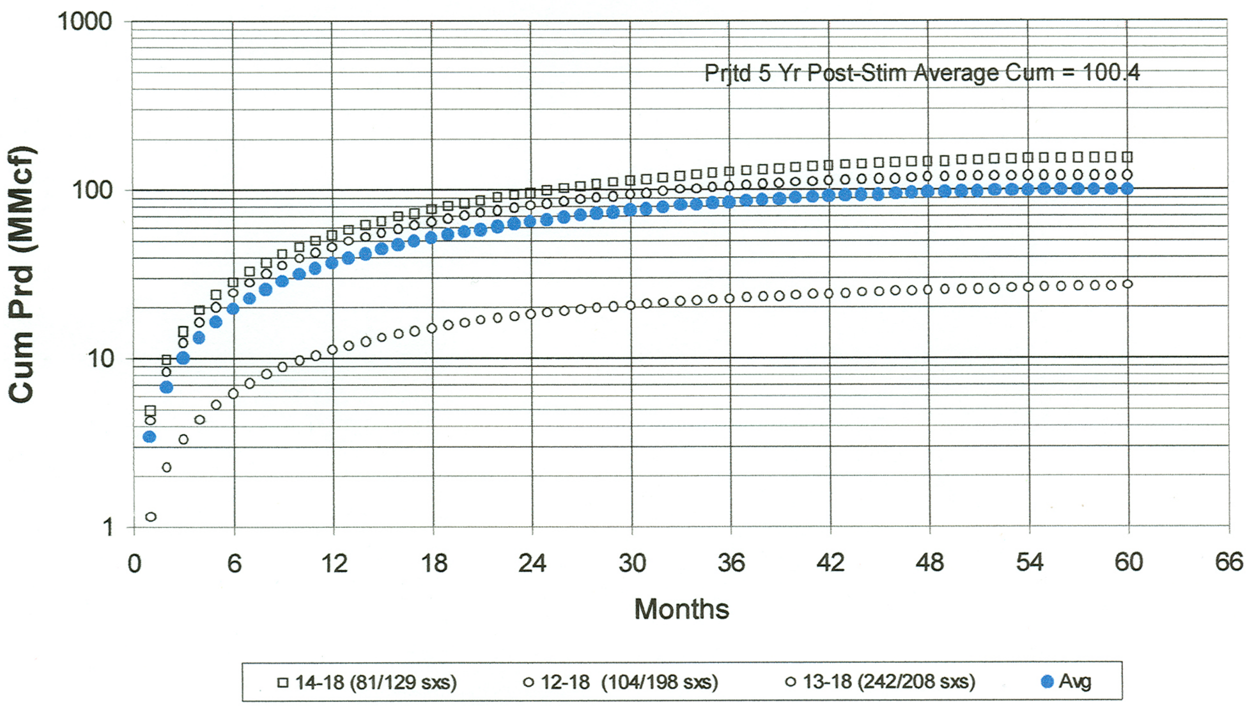
The five year cumulative production volumes from the seven Control Wells ranged from 65.8 to 1,695.2 MMcf and averaged 745 MMcf.



(b) Summary – Candidate Wells

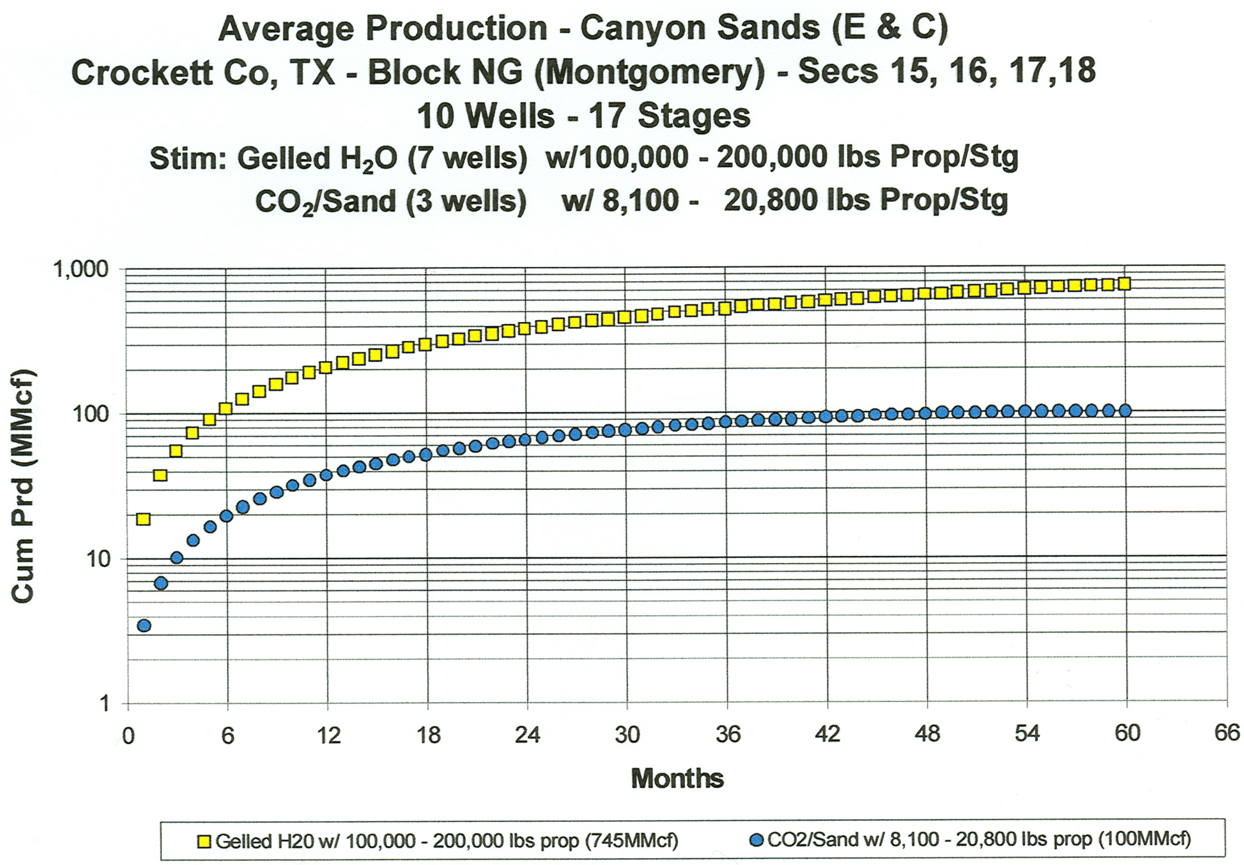
The five year cumulative production from the three Candidate Wells ranged between 26.7 and 153.6 MMcf and averaged 100.4 MMcf.

Production - Canyon Sands (E & C)
Crockett Co, TX - Block NG (Montgomery) - Sec 18
3 Wells - 6 Stages
Stimulation: CO_2/Sand - 2 Stages - w/8,100 - 20,800 lbs Proppant/Stg



(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. Test Area #1B - Block MM (Hoover-Hatton) – Single Stage Completions

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

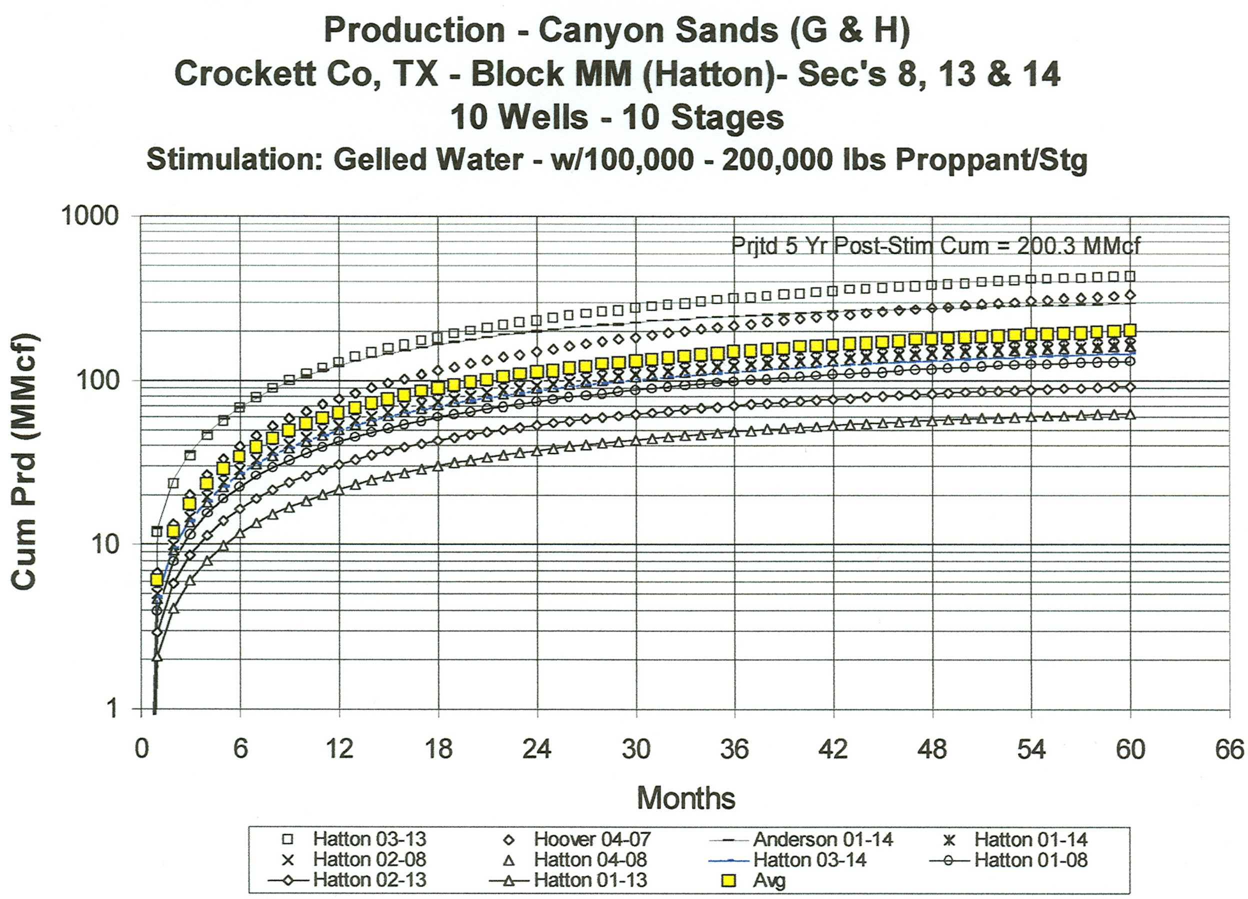
	Sand (sacks)		Max Tr Press	Avg Rate	Sand Conc	
Well	Pumped	In-Zone	Psi	BPM	Max	Avg
13-14	139	56	7,400*	39.0	2.0	1.1
7C-7	112	102	6,050	39.5	1.0	0.8
8C-4	140	117	6,250	40.0	2.0	1.0
* Well equipped with P-110 casing						

c. Results

(1) Production Comparisons

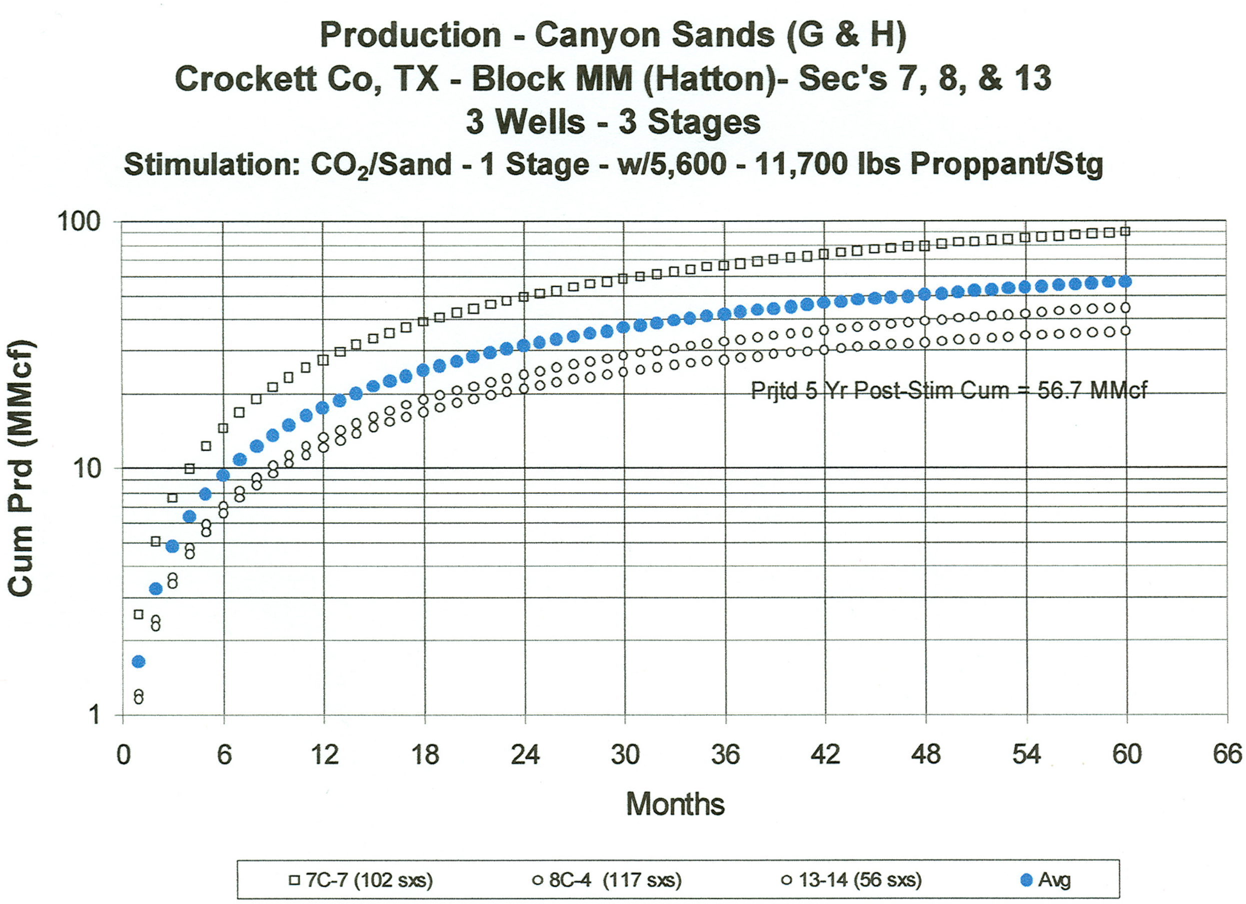
(a) Summary – Control Wells

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



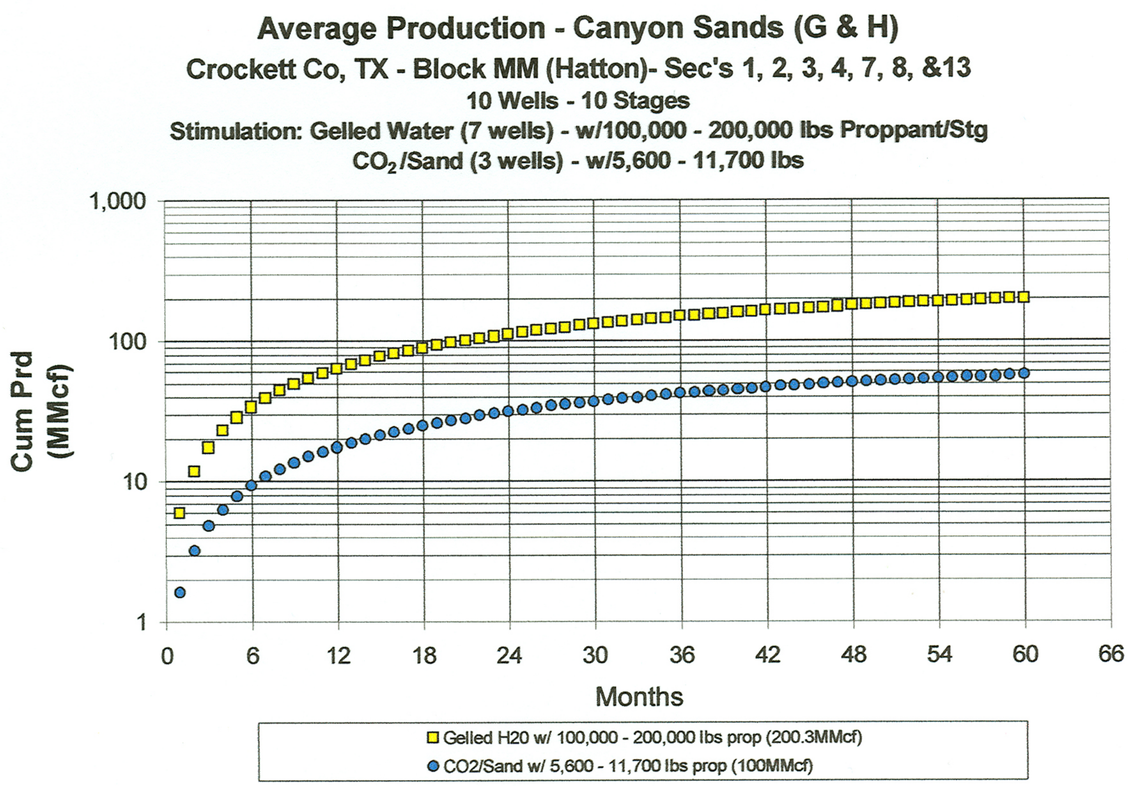
(b) Summary – Candidate Wells

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:

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

(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.

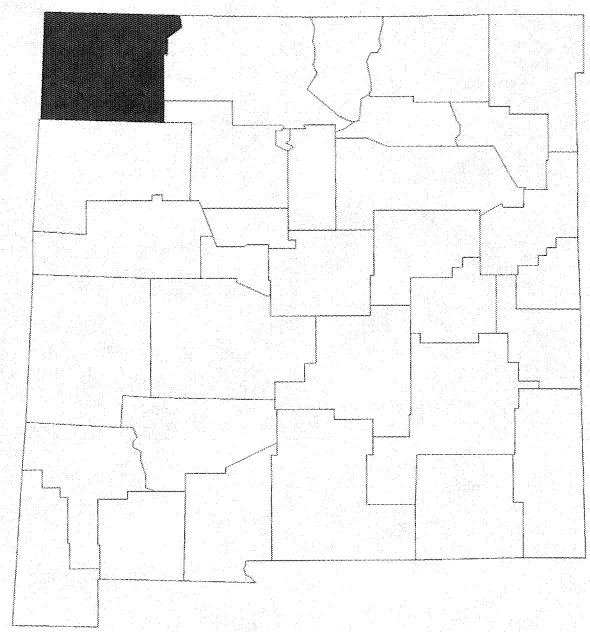
(8) Summarizing, the conclusion is that fracture lengths longer than those which can be generated with CO_2/Sand stimulations are required in this area. It is too "tight".

(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

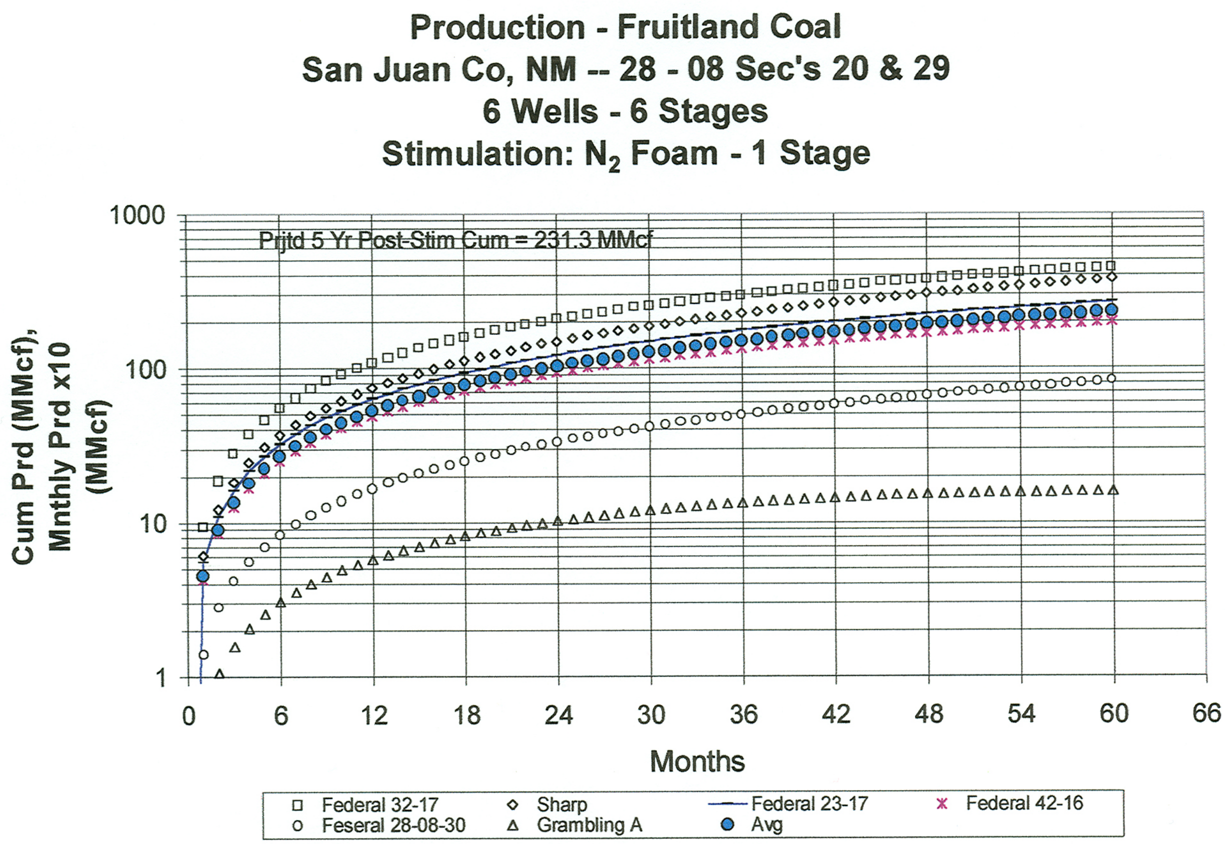
A review of the phase behavior at these temperatures and pressures confirmed that the CO_2 would vaporize under these conditions. A phase diagram for each well group was prepared and is not included here, but accompanies the report for that group

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

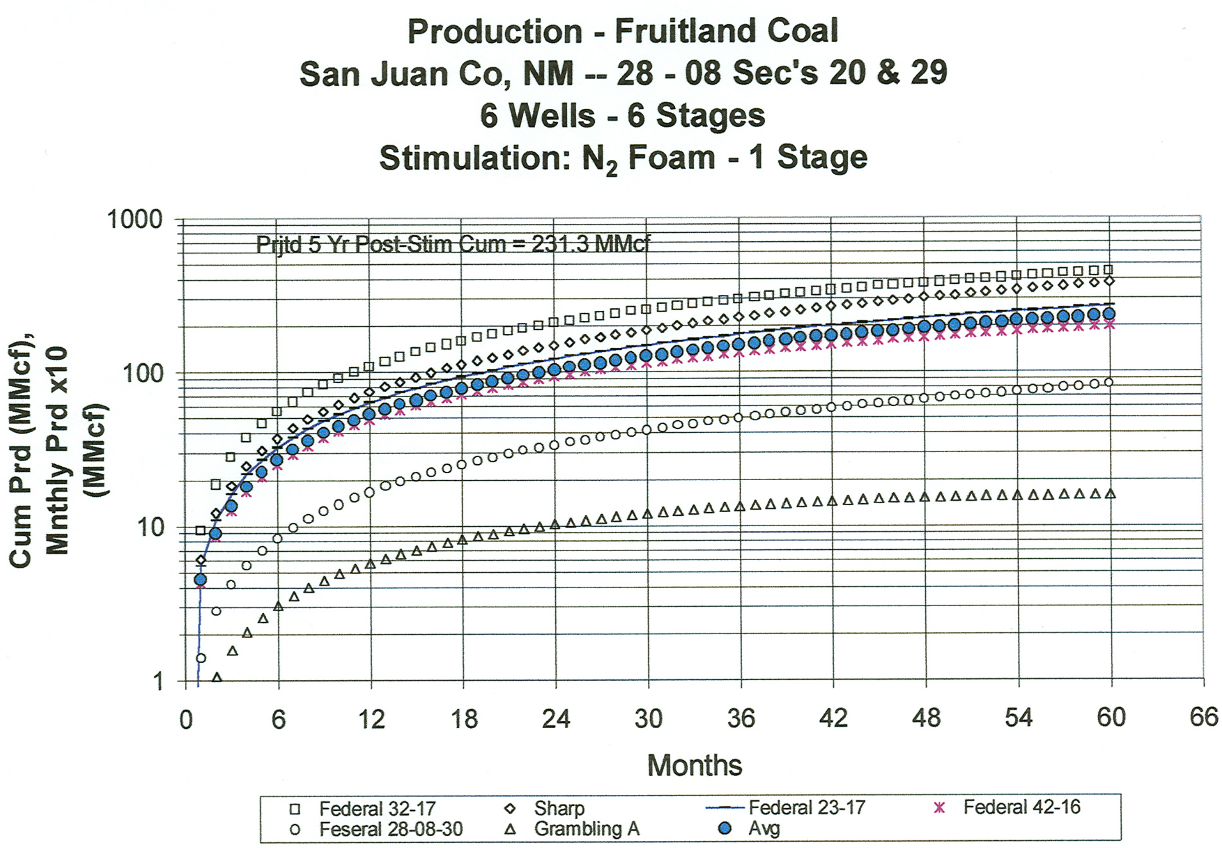
The casing pressure in the offset well increased from 127 to 460 psi, and the production increased from 190 to 420 Mcf per day indicating the communication with the Candidate Well. Additionally, a gas sample was obtained following the treatment and was reported to contain 44% CO_2, indicating communication 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

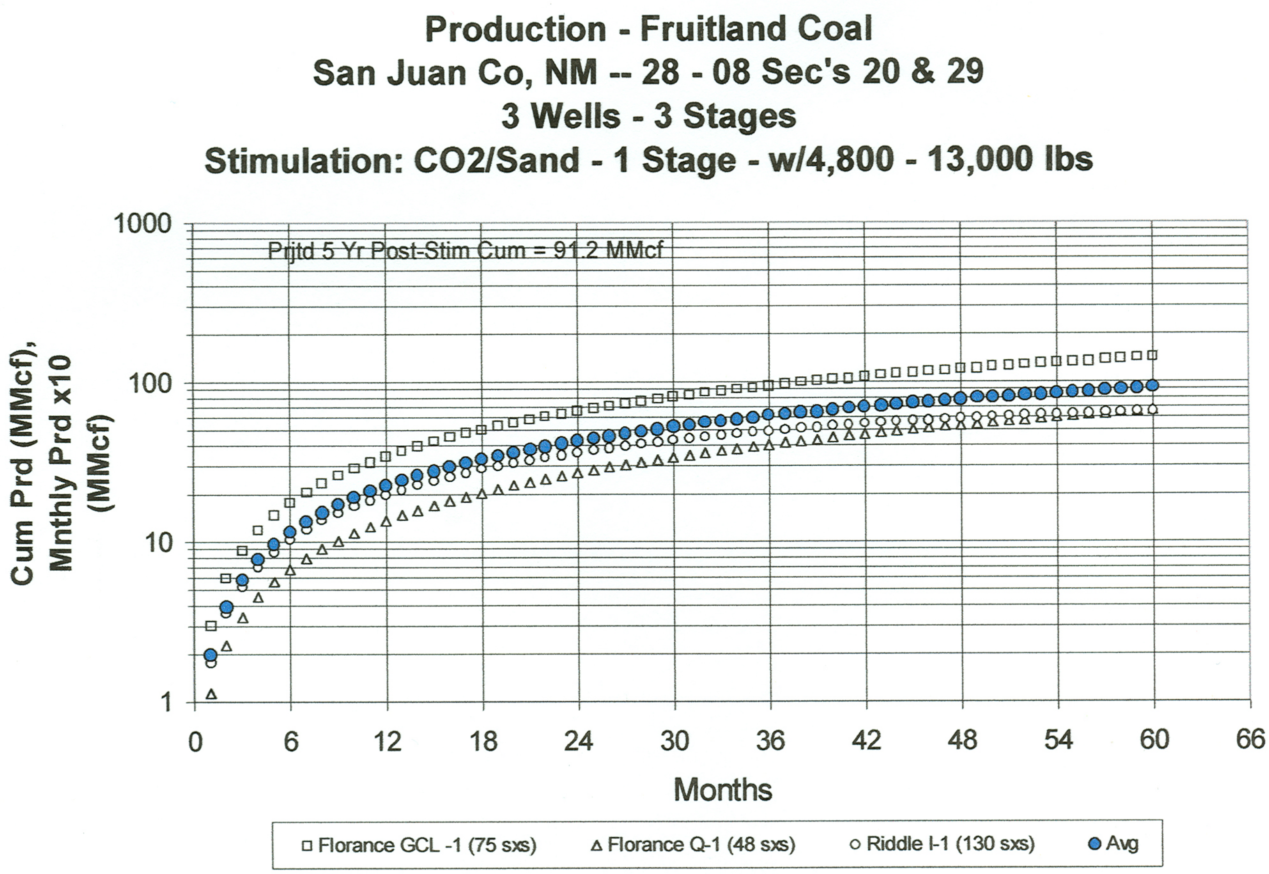
(1) Summary – Control Wells

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

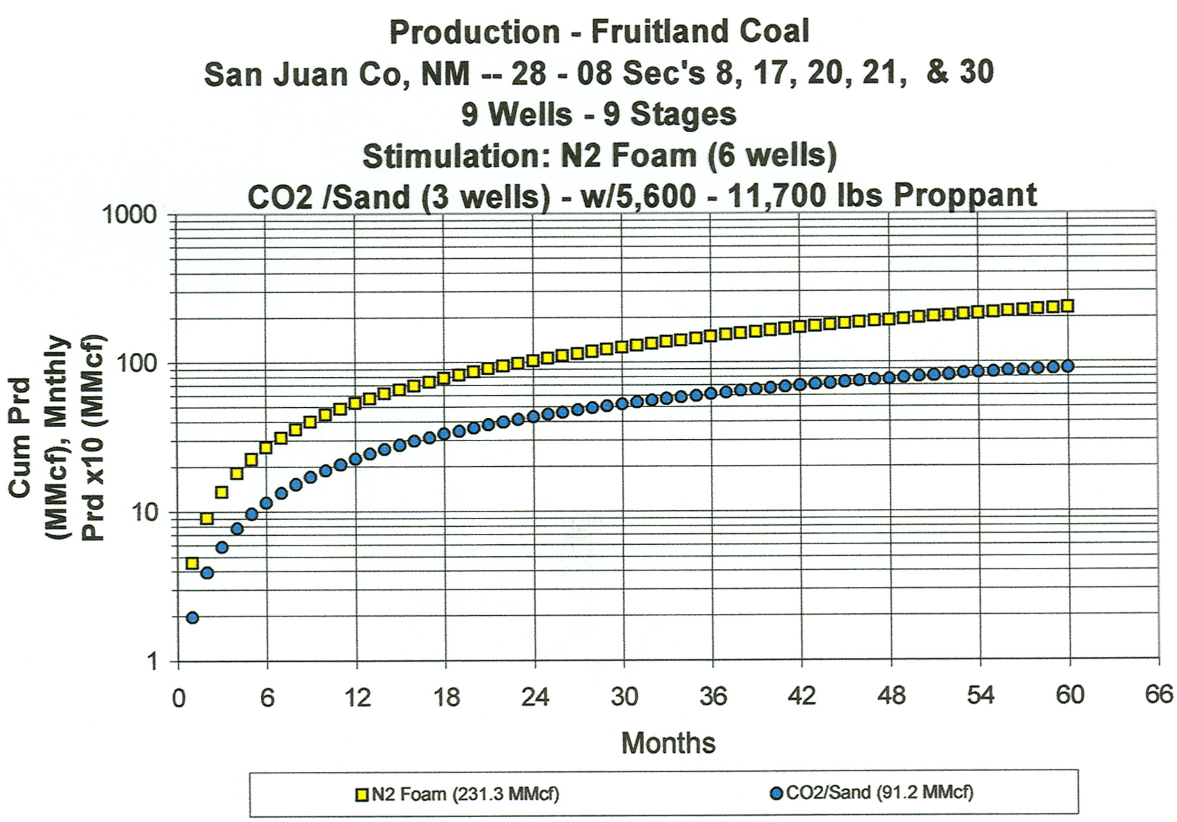
The five year cumulative production from the three Candidate Wells ranged between 65.3 and 141.9 MMcf and averaged 91.3 MMcf.



(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:

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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

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.

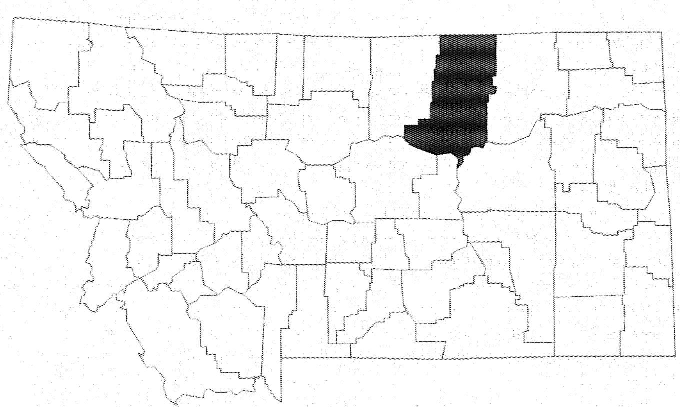
The placed proppant volumes obtained in the liquid CO_2 treatments was only on the order of three percent (3%) of that placed with conventional treatments, and although the production from the liquid CO_2 stimulations averaged 39 percent of that from the conventionally stimulated wells suggesting that 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.

	Cum Prod Months 2-13
Well #	(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:

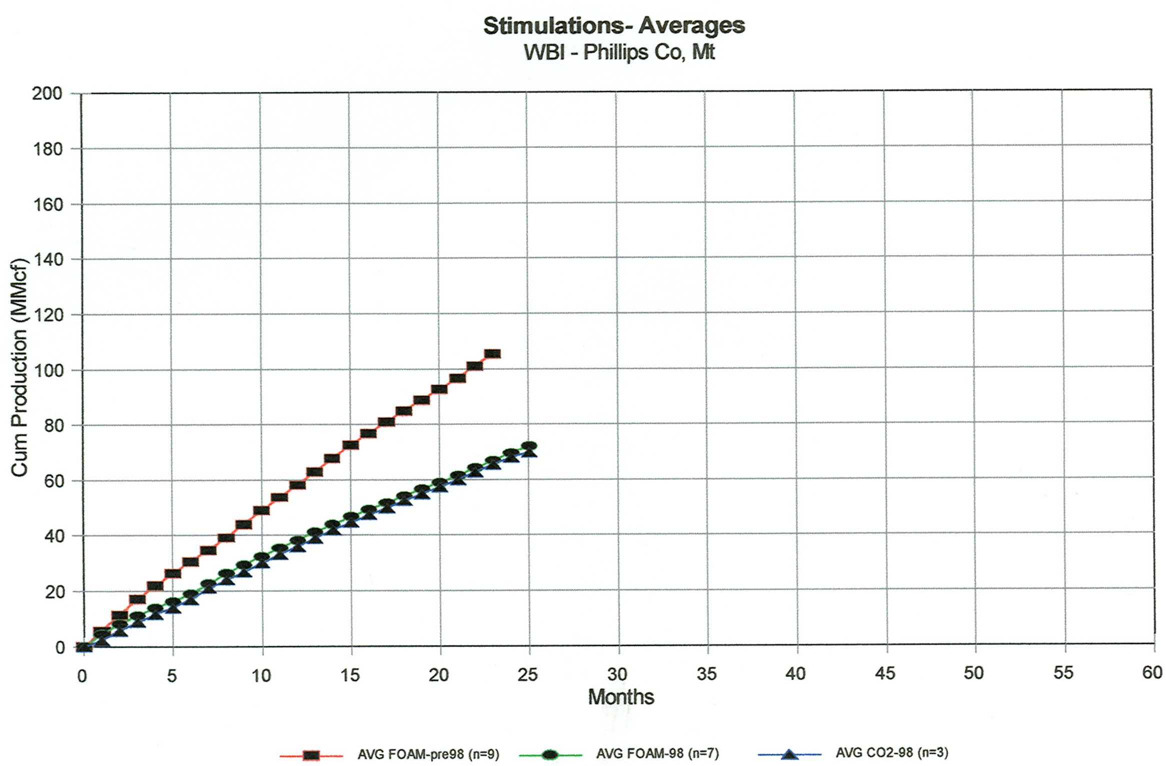
(1) N_2 Foam - Pre July 1998 (Control Wells)

(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.

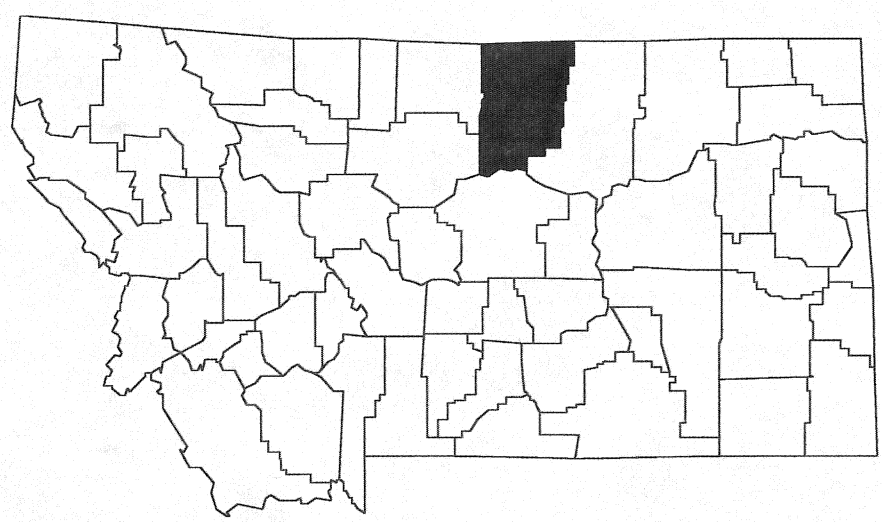
d. The twenty-four month cumulative production volumes from the wells stimulated with the liquid-free CO_2/sand process are essentially the same as that from the Control Wells treated with N_2 Foam and utilizing the same 40,000 pound proppant volume.

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:

Well	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													
S-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:

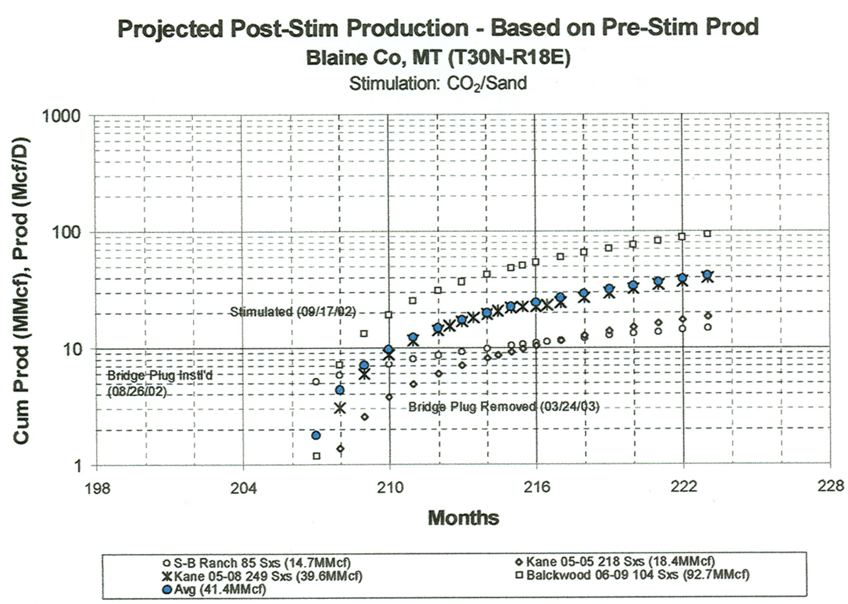
		CO_2	Sand (lbs)		Max Tr	Avg Rate	Sand Conc	
Well	# - S	Bbls	Pumped	In-Zone	Psi	BPM	Max	Avg
S-B Ranch	02-05	432	10,300	8,500	3,115	37.8	2.4	1.2
Kane	05-08	835	27,300	24,900	3,147	31.0	2.3	1.0
Kane	05-05	815	23,800	21,800	3,495	46.0	2.4	0.9
Blackwood	06-09	633	10,600	10,400	3,408	20.0	1.3	0.6

10. Results

a. Production Comparisons - Pre and Post Stimulation

(1) Pre-Stimulation

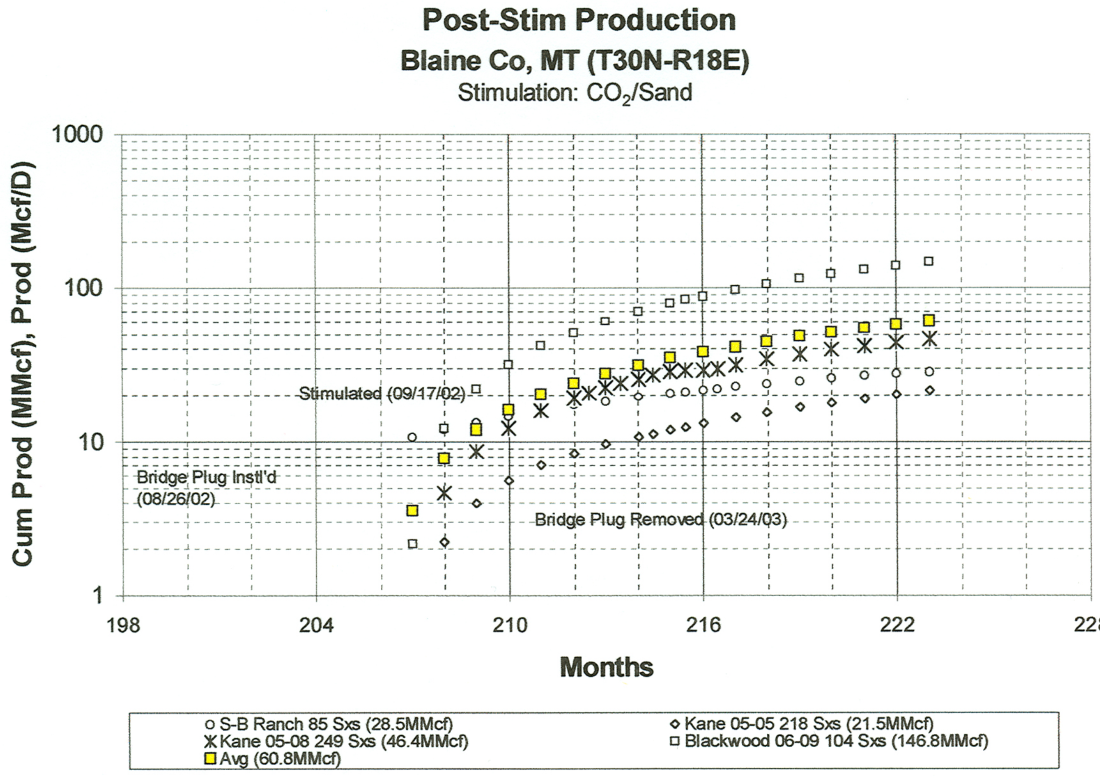
The pre-stimulation production from the four Candidate Wells was extrapolated to project the future production, and these projections served as the basis to which the production following the stimulations was compared. The projected post-stimulation volumes ranged from 14.7 to 92.7 MMcf and averaged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



(2) Post-Stimulation

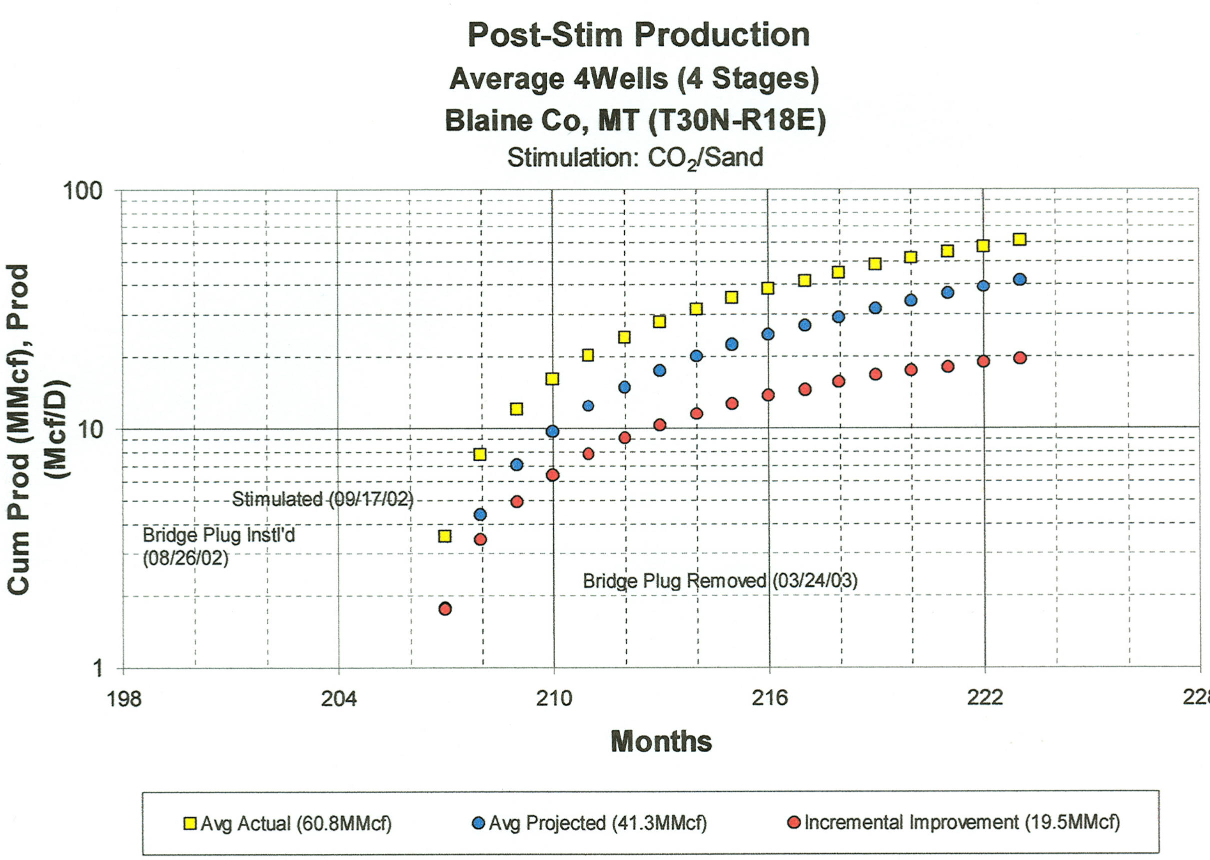
Ocean failed to provide the production data as per contract and it was obtained from public data sources (through July, 2004). The public data is reported on a monthly basis and does not include the number of producing days and therefore the production comparisons do not take into account any non-production 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

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