Approved: MARch 22, 2000
Date

MINUTES OF THE SENATE UTILITIES COMMITTEE.

The meeting was called to order by Chairperson Sen. Pat Ranson at 1:30 p.m. on March 2, 2000 in Room 231-N of the Capitol.

All members were present

Committee staff present:
Lynne Holt, Legislative Research Department
Mary Torrence, Revisors of Statute Office
Jeanne Eudaley, Committee Secretary

Conferees appearing before the committee:
Robert Krehbiel, Executive Vice Pres., Kansas Independent Oil and Gas Association
David Nickel, Legislative Chairman, Kansas Independent Oil and Gas Association
James Daniels, General Manager, Murfin Drilling Company, Inc.

Others attending:
See attached list

In the absence of Sen. Ranson, who is attending a Post Audit meeting, Sen Clark called the meeting to order and stated the committee will hear **HB 2826-oil and gas; relating to unitization and unit operations**. He introduced Robert Krehbiel, who gave information regarding unitization and the reason for the bill (Attachment 1). He explained the need for unitization comes about when an older oil well's pressure is pumped off. He referred to a map (which is attached to his testimony) showing an oil field in Clark County, and explained it to the committee and referred to the third page of his testimony, which demonstrates the acreage participation in a unitization agreement. The initial pressure allows recovery of about 20% of the oil in the underground oil or gas reservoir. Recovery is continued by converting an existing well into an injection well which forces water or carbon dioxide (CO_2) down the well to repressurize the underground reservoir. This re- pressurization forces oil into the pumping units of all the wells that draw out of the same reservoir. He pointed out the problem arises when owners begin draining off the oil or gas from another's well. The unitization agreement involves working interest owners and royalty owners being located, which is increasingly difficult to do. Kansas has a compulsory unitization law which requires that 75% of the royalty owners and working interest owners must be involved in the negotiations and agreement before submitting it to the KCC for final approval.

Mr. Krehbiel stated the Interstate Oil and Gas Compact Commission, which is an organization of thirty producing states including Kansas, has reviewed unitization statutes, hoping to promote recent technological advancement. The study concluded that "a flexible unitization statute promotes increased use of technological advancements". After reviewing the Kansas law and consultations with the Royalty Owners Association and the KCC, the bill being considered was drafted, making minor changes to the current law to make the Kansas law more flexible. Mr. Krehbiel answered questions from the committee, including Sen. Clark, regarding if unitization can be done at different depths, and he answered it can be unitized as much as two to three layers. Answering a question from Sen. Barone regarding compulsory unitization, Mr. Krehbiel answered that unitization is a lengthy process and cannot be done if 25% or more of the owners refuse to enter the agreement or cannot be located. He pointed out that the bill changes the 75% requirement to 63% in the agreement and any working interest may submit a request for a fair and reasonable compulsory unitization from the KCC. In answer to a question regarding equal compensation for all working interest owners, Mr. Krehbiel clarified that the compensation is in the increased production of the oil wells after the unitization agreement.

Sen. Ranson introduced David Nickel, who explained the bill to the committee (Attachment 2) and answered questions. Sen. Barone questioned the strong wells vs. weak ones and asked Mr. Nickel to explain the basis for participation. He answered the allocation is based on several criteria, such as the number of wells, past production, location, etc. The owners involved in the negotiation work toward what is fair for all and attempt to accommodate the 63%, because they anticipate a benefit to every owner. Sen. Clark asked questions regarding who would bear the costs of repressurization and how the 63% is assessed - does it relate to working interest owners, number of wells, or production? Mr. Nickel responded that the allocation is based upon the various producing units and active working interests involved in the field; then the percentages are determined with costs then allocated to the various operating units. He emphasized that under the current law, the plan is set and when determination of costs has been made, it is submitted to the KCC for their approval. Mr. Nickels also emphasized that logistics are hard because of the number of people involved around the world and the reason for the bill is to expedite the process.

Sen. Ranson introduced James Daniels, who described the primary production of wells, which occurs as the energy source is depleted or reduced, and the recovery of large volumes of oil which remain in the reservoir without energy to move it (Attachment 3). He described the secondary recovery as water being introduced into the existing wells to cause movement; consequently there is a substantial increase in production, and he gave the committee examples of the increases. He told about new technological strides made by the oil and gas industry to develop methods to recover portions of unrecovered oil remaining in reservoirs and that 30 to 50% of the original oil is all that can be expected to be recovered through primary combined with secondary means. He continued by citing studies conducted at the University of Kansas and the Kansas Geological Survey have described a tertiary recovery technique called the CO 2 (carbon dioxide) process. His company is initiating a pilot project on the Colliver and Carter oil leases where there are 89 royalty owners involved who live throughout the U.S., and he told of the difficulty in contacting 75% of them, some with a small interest in the project. Mr. Daniels stated the proposed CO 2 pilot program on the leases has a better chance of being successful if the two properties can be unitized; he stated his experience has been that the difference between the 63% and the 75% in agreement in the working interest owner and the royalty owners can make or break the potential for unitization. He closed by stating that Kansas' principal remaining oil reserves lie in the secondary and tertiary phase of oil recovery, and the recovery of that oil benefits local economies as well as the state economy. He urged the committee to pass the bill which will enable the oil and gas industry to initiate and operate the secondary and tertiary projects in Kansas. Mr. Daniels discussed with the committee the difficulty in putting the units together, and that objections to the bill could come from the owners of larger percentages who could hold out for better benefits and hurt the small owners. Sen. Brownlee asked who initiated the bill and how are the units are taxed now. Mr. Daniels answered the industry requested the bill; that the individual operator is taxed and passes it on to the unit, and that the royalty owners are also taxed. Sen. Ranson asked if anyone from the KCC was present, and acknowledged that Diana Edmiston was present and is assistant general counsel for the Conservation Division of the KCC. Sen. Ranson announced the hearing will continue next Tuesday, and requested Ms. Edmiston, or someone else from the KCC, be present to inform the committee of its role regarding the bill and the Commission's response to the bill.

Sen. Ranson also announced the review on plugging abandoned wells will be next Wednesday, with a public hearing on Thursday.

Meeting adjourned at 2:30.

Next meeting will be March 7, 2000.

SENATE UTILITIES COMMITTEE GUEST LIST

DATE: MARCH 2, 2000

NAME	REPRESENTING
Don Schnacke	Shell Oil Co. Ltd.
Ken Peterson	KS Petroleum Council
Robert E Krehbiel	KIOGA
James R Daniels	Murfin Drilling Co
David Nickel	KIOGA
Gerard Nickel	Guest
Dennis Edmiston	KCC
ED SCHAUB	WESTERN RESOURCES
Cynthia Smith	KCPL
[illegible]	Hein [illegible]

A-1

KANSAS INDEPENDENT OIL & GAS ASSOCIATION
105 S. BROADWAY • SUITE 500 • WICHITA, KANSAS 67202-4262
(316) 263-7297 • FAX (316) 263-3021

TESTIMONY OF ROBERT E. KREHBIEL, EXEC VICE PRESIDENT
OF THE KANSAS INDEPENDENT OIL AND GAS ASSOCIATION
BEFORE THE SENATE COMMITTEE ON UTILITIES
ON HOUSE BILL 2826
MARCH 2, 2000

Madam Chair and Members of the Committee:

My name is Robert E. Krehbiel and I am appearing on behalf of the Kansas Independent Oil and Gas Association in support of H.B. 2826. Mr. David Nickel, Attorney with Depew & Gillen, and Chairman of our Legislative Committee, is here today to explain the bill, and Jim Daniels, a Geological Engineer and General Manager of Murfin Drilling Company is here to explain the practical uses of unitization and new technology which we hope will increase the use of Kansas' Unitization statutes.

The Interstate Oil and Gas Compact Commission, an organization of thirty producing states including Kansas, has been reviewing the unitization statutes of the various states with a view towards promoting the use of recent technological advancements which might increase the need for unitization. The IOGCC study concluded that "a flexible unitization statute promotes increased use of technological advancements".

We are excited about the potential of bringing technological advancements to the Kansas oil patch. Dramatic increases in the production of Kansas crude oil may be possible. This has caused us to review our own unitization statute and make a few alterations. We have communicated with large producers including Mobil and OXY and with the Southwest Kansas Royalty Owners Association and their Counsel about H.B. 2826 and with the Kansas Corporation Commission. Their input has been included in this bill.

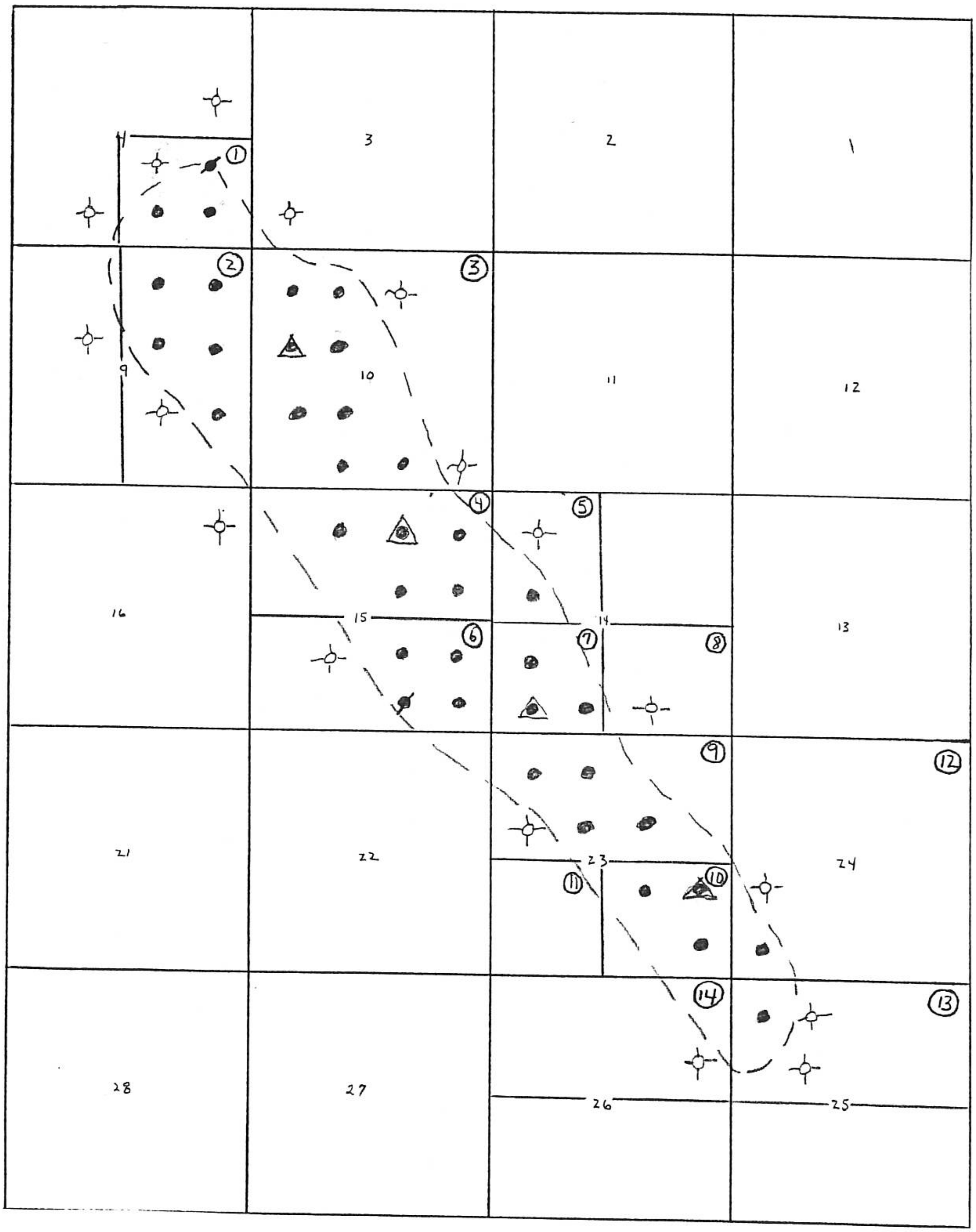
The subject matter of this bill is unitization and it was suggested that a brief description of this process would be useful to the Committee. I have attached a simple drawing to briefly explain this concept.

Thank you for having this hearing. We hope you will act favorably on H.B. 2826.

Senate Utilities
3-2-00
Attach. 1

CLARK COUNTY, KANSAS

T 35S - R 23W



- Oil Well
- Gas Well
- Dry Hole
- Injection Well
- Edge of Field

① thru ⑭ Oil & Gas Leases

	Oil & Gas Leases	Acreage In Unit	Acreage Participation
1	160 ac	120 ac	.062500
2	320 ac	260 ac	.135417
3	640 ac	400 ac	.208333
4	320 ac	240 ac	.125000
5	160 ac	50 ac	.026042
6	320 ac	150 ac	.078125
7	160 ac	160 ac	.083333
8	160 ac	10 ac	.005200
9	320 ac	200 ac	.104167
10	160 ac	150 ac	.078125
11	160 ac	10 ac	.005208
12	640 ac	50 ac	.026042
13	320 ac	80 ac	.041667
14	320 ac	40 ac	.020833
Total	4,160 ac.	1,920 ac.	1.0000

A-2

TESTIMONY BEFORE THE
SENATE COMMITTEE ON UTILITIES

by David W. Nickel,
Legislative Chairman
Kansas Independent Oil and Gas Association

Re: House Bill 2826

Date: March 2, 2000

Thank you for this opportunity to speak to the Senate Committee on Utilities of the Kansas Legislature. My name is David W. Nickel. I am an attorney-at-law. I am currently the Legislative Chairman for the Kansas Independent Oil and Gas Association (KIOGA).

I am a member of the KIOGA committee which studied the amendments set forth in House Bill 2826 and am here to explain those amendments. The work of the KIOGA committee emanated from a seminar on field wide unitization and the IOGCC model statute which was presented in New Orleans, Louisiana, on December 14 and 15, 1999. As the committee knows, the Interstate Oil and Gas Compact Commission is a compact of several producing states, of which Kansas is a member.

All told, I believe the statutory scheme relating to the unitization and unit operations in Kansas is a very good one. However, the KIOGA committee found a few provisions which need slight modification in order to modernize the unitization statutes. The proposed amendments are to K.S.A. 55-1304, 55-1308, 55-1312 and K.S.A. 1999 Supp. 55-1305.

First, H.B. 2826 amends K.S.A. 55-1304(a) to delineate the current law that an application seeking unit operation can be filed with the KCC either when artificial energy will be introduced into the reservoir, or when artificial energy will not be introduced into the reservoir but unit operation is economically feasible and reasonably necessary to prevent waste within the reservoir, thereby increasing substantially the ultimate recovery of oil or gas.

In connection with the proposed amendment to K.S.A. 55-1304(a), House Bill 2826 would also amend K.S.A. 55-1305(l). That statutory provision would be amended to provide that a plan for unitization of an oil or gas reservoir (if approved by the KCC) would become effective as follows:

> If the plan of unitization, as approved by the Kansas Corporation Commission, contemplates the introduction of artificial energy into the reservoir, then the plan of unitization will become effective upon approval in writing by 63% of the working interest owners and 63% of the royalty interest owners (excluding overriding royalty interest and other like interests); however, if the plan of unitization, as approved by the KCC, does not contemplate the introduction of artificial energy into the reservoir but is determined by the KCC to be

Senate Utilities
3-2-00
Attach. 2

> necessary to prevent waste and economically feasible, then the plan of unitization will become effective upon approval in writing by 63% of the working interest owners and 75% of the royalty interest owners (excluding overriding royalty interest and other like interests).

Under current law, no plan for unitization is effective until it is approved in writing by 75% of the working interest owners (or other persons who are required to pay the cost of unit operation, if any) and also by the owners of 75% of the production or proceeds that are free of cost (such as royalties, overriding royalties, production payments, and other like interests).

This proposed amendment comes directly from the information which was derived by the KIOGA committee members through the IOGCC seminar on unitization. Seminar material showed that a large number of states do not require such a high percentage as 75% of the working interest owners and royalty interest owners in order to make a unitization plan effective. In fact, Oklahoma unitization statutes only require 63% in these regards. Thus, House Bill 2826 brings the Kansas unitization statutes more in line with what other states are doing with respect to owner ratification of unit plans.

It bears pointing out that, under the proposed amendments as well as current law, the filing of an application with the KCC and, indeed, KCC approval of that application is required for any unit plan to become effective regardless of the percentage of owners who ratify the plan. House Bill 2826 would also amend K.S.A. 55-1305(l) to ensure that overriding royalty interest owners cannot dilute the vote of landowner royalty interest owners with respect to approval or disapproval of any unit plan.

In addition, to accommodate very small units where there may be only two single working interest owners, H.B. 2826 would amend K.S.A. 55-1305(i) by striking the following phrase:

> However, in no event shall the vote of a single working interest owner control unless a single working interest owner is liable for all of the costs.

The KIOGA committee was concerned that in very small units where there are only two working interest owners, that language which is currently in the statute allows a small working interest owner to unreasonably veto unit operations which may be necessary to prevent waste. Certainly, if that veto power is desired by the parties to such a unit or by the KCC, such a veto power could still be provided in the unit plan.

H.B. 2826 would also amend K.S.A. 55-1305(f) to ensure that nonoperating working interest owners shall be furnished reasonable detailed information regarding the nature and amount of various items of costs and expenses chargeable against the interest of the nonoperating working interest owners. Thus, detailed information must be supplied not more often than once a month to each nonoperating working interest owner (without the owner needing to make a written request to the operator).

H.B. 2826 also contains an amendment to K.S.A. 55-1308 with respect to unleased tracts of land which are included in the unit. Under current law, these unleased tracts of land are regarded as a working interest to the extent of 7/8ths interest and a royalty interest to the extent of a 1/8th interest. However, in certain areas of the state, a 1/8th royalty interest may no longer be common or appropriate, and the amendment is intended to give effect to higher royalty interests if those are granted to landowners as the industry practice in the pertinent area. Finally, it is recommended that K.S.A. 55-1312 be amended to clarify that the property of the several working interest owners in the unit shall be assessed and taxed together as a single unit. These amendments will take effect after publication of the amendments in the Kansas Register.

The KIOGA committee consists of representatives of small and large producers, the Kansas Corporation Commission staff, and the Southwestern Kansas Royalty Owners' Association. The committee appreciates the work and cooperation of these representatives which allow these amendments to the unitization statutes to be proposed to the Kansas Legislature. Thank you again for this opportunity to speak to the Kansas Legislature.

A-3

MURFIN DRILLING CO. INC.

CONTRACTORS AND PRODUCER

TESTIMONY OF

JAMES R. DANIELS, GENERAL MANAGER OF MURFIN DRILLING COMPANY, INC.

ON H. B. 2826

BEFORE THE SENATE UTILITIES COMMITTEE

MARCH 2, 2000

Senate Utilities
3-2-00
Attach. 3

TESTIMONY OF

JAMES R. DANIELS, GENERAL MANAGER OF MURFIN DRILLING COMPANY, INC.

ON H. B. 2826

BEFORE THE SENATE UTILITIES COMMITTEE

March 2, 2000

Madam Chairman Ranson and members of the Committee:

My name is James R. Daniels, General Manager of Murfin Drilling Company, Inc. appearing in support of H. B. 2826

First, let me briefly describe the mechanisms which account for oil and gas production. There must be a reservoir rock, normally in Kansas these are limestone, dolomite, chert and/or sandstone. These rocks must contain porosity or holes in order to be reservoirs or containers of hydrocarbons. Further, they must exhibit permeability or the holes must be interconnected. For oil to move to a well bore it must have a driving force (reservoir energy) which initially can be gas contained in solution in the oil, gas in the form of a cap on top of the oil, water below the oil acting to push the oil (active water drive), or a combination of two or all three of these sources. The first phase of production is termed primary production and occurs from first completion until the energy source moving the oil is depleted or reduced to a very small amount. In the case of solution gas and gas cap type reservoirs, recovery of initial oil in place can vary from less than 10% to as great as 20% plus. Thus, large volumes of oil remain in the reservoir without energy to move it to a well bore. In the case of an active water drive, as much as 30 to 50% of the oil in place may be produced before production becomes non commercial. Toward the end of the primary cycle, large volumes of water are produced with the oil, in this instance.

To recover additional volumes of oil remaining in the reservoir in all but active water drive production an additional energy source must be introduced. Logically, since active water drive type reservoirs recover a much larger percent of the oil in place, the oil industry many years ago began 'waterflood' operations in producing fields. This method of secondary recovery is simply described as water being introduced into the producing formation thru either existing well bores, such as a converted oil well or recompleted dry hole or thru a new specifically drilled injection well. Murfin currently operates 26 of this type project, of which 16 are units.. This method has been demonstrated to recover as much as an additional 20% of the original oil in place, thus it can approximate or exceed recovery by primary energy. The same has been demonstrated for gas injection where natural gas is introduced into the reservoir instead of water. Often reservoirs are subjected to both gas injection in up dip or gas cap wells and water injection into structurally low or down dip wells. To give an example of the effectiveness of secondary recovery, in these cases, waterflood, have included with copy of my testimony, decline curves which depict rates of production vs. time in graphic form and unit maps of two examples:

a) Gano SE Unit - Graham County, Kansas (Exhibit A-1 and A-2)
b) Ung Unit - Decatur County, Kansas (Exhibit B-1 and B-2)

The decline curves depict performance of producing wells prior to and after water injection. The charts/graphs are on semi-logrithmic paper, the vertical depicts monthly oil production on the logrithmic scale, while the horizontal scale depicts time in months and years. In examining these graphs, one can readily see the stimulation to productive rate created by water injection into one or more wells in the unitized area. Start with the Gano SE Unit, date of unitization was September 1985. Oil production prior thereto from all leases was averaging approximately 800 barrels per month. Four wells were converted to injectors with injection commencing in October 1985. You can see the effect in time of this injection with production peaking in early 1989 and holding steady thru the year in excess of 5,000 barrels per month before starting gradual decline in 1990. Combined oil production for leases in the unit, prior to unitization was 1,120,428 barrels. Thru December 1998, production after unitization has been 499,645 barrels. While some additional oil could be considered attributable to primary energy, the bulk of the oil produced between 1985 and 1998 was due to waterflood or secondary recovery. This large increase was facilitated and largely made possible by the ability to unitize six separate leases to form the Gano Unit which could be then operated as one property.

Now let's examine the Ung Unit performance. Prior to water injection, average production was between 400 and 600 barrels oil per month. Injection started in August 1988 and peaked in mid 1991 at 1800 - 1900 barrels oil per month. Seven individual leases were unitized to form the Unit. Prior to unitization, leases had a combined recovery of 268,840 barrels of oil. Subsequently thru December 1998, an additional 138,869 barrels of oil had been recovered thru water flooding.

Additional technological strides have been made by the oil and gas industry in developing methods to recover a major portion of the yet unrecovered oil remaining in reservoirs, even after active water drive and secondary recovery operations. You may recall, from 30 to 50% of the original oil in place is all that can be expected to be recovered thru both primary combined with secondary means. Thus, half or more of the oil normally remains in the reservoir. Studies conducted by the University of Kansas Department of Petroleum Engineering, the Kansas Geological Survey and their combined Tertiary Oil Recovery Program (TORP), headquartered in Lawrence, have indicated a tertiary recovery technique entitled the CO_2 (carbon dioxide) injection process, is likely to recover yet a substantial increment of the remaining oil in place. Estimates range up to an additional 15 to 20% of the original oil in place, which is equivalent to average each of the primary and secondary recovery sequence. The CO_2 recovery process has been demonstrated to be highly successful in recovering large volumes of oil from fields in eastern New Mexico, west Texas, and parts of Oklahoma, including the panhandle just south of the Liberal - Elkhart area in Kansas. Kansas TORP has preliminary laboratory data which indicates the CO_2 process is expected to be a successful tool in recovering additional oil particularly from zones of the Lansing - Kansas City Formation known to be productive in many Kansas Counties. Have attached a copy of the Executive Summary of a report by TORP entitled "Field Demonstration of Carbon Dioxide Miscible Flooding, in the Lansing - Kansas City Formation, Central Kansas", Exhibit C. A 'pilot' project is to be initiated this year on two leases, the Colliver and Carter, operated by Murfin in Russell County, Kansas southeast of the city of Russell, to determine the economic feasibility of CO_2 recovery in the Lansing - Kansas City Formation. Have enclosed a map of the Colliver and Carter Leases, see Exhibit D, and adjoining area to demonstrate the project. Thru December 1998, oil production from these leases was Colliver 2,403,209 barrels and Carter 658,282 barrels. While not all the oil was produced from the Lansing - Kansas City, by far the majority was. It is projected that 94,800 barrels of oil can be recovered from a 40-acre 'pilot' CO_2 miscible recovery process of the B & C zones of the Lansing - Kansas City Formation underlying the Carter and Colliver leases. The same studies indicate that if the 'pilot' program reacts favorably as projected, as much as 600 to 800 million barrels of oil may be ultimately recoverable by employing the CO_2 process in Lansing - Kansas City reservoirs throughout Kansas. To a degree, the success of this and other potential secondary and tertiary recovery programs in the state depend on the ability of Kansas operators to unitize entire reservoirs or major portions thereof.

Murfin has a combined eighty-nine (89) royalty owners involved in the Colliver and Carter leases. They are scattered from North Carolina to California and from Illinois to Texas. Obviously from their number and the one-eighth (0.125) they represent, most of the interests are extremely small. Occidental (formerly Cities Services) operated the leases prior to purchase by Murfin and associates thru the primary and secondary phases, including waterflooding of the Lansing - Kansas City Formation. Whether because of the large number of royalty owners or for other reasons unknown to Murfin, the two tracts were never unitized, instead to protect correlative rights, injectors were drilled on several of the lease lines, not only between the Carter and Colliver, but adjacent leases as well. Having dealt with numerous waterflood operations, know employment of line well injectors or compensating offset well injectors is an established method to recover additional oil; however, it often does not afford the most economically efficient means, nor the method which best protects correlative rights of all owners. To unitize, if possible, all the leases covering the producing reservoir as was done with Murfin's Gano SE and Ung Units, is the most economically efficient method and one which minimizes the number of required injectors recovers the maximum amount of oil and best protects correlative rights. The proposed CO_2 pilot program involving the Colliver and Carter leases, has its best chance for success if the two properties can be unitized. To have to only obtain 63% approval of the eighty-nine (89) royalty owners will be considerably easier than obtaining seventy-five (75%) percent. This situation can be multiplied throughout many areas of Kansas where older oil production exists, where mineral interests were severed, sub sold, then death and heirship further divided the interests. I've personally seen royalty ownership even more segregated than on the Colliver and Carter and have seen situations where addresses were unknown for numerous owners. Also, have seen where the difference between 63% and 75% in agreement both in the working interest owner and the royalty owner sides, can make or break the potential for unitization. Kansas principal remaining oil reserves lie in the secondary and tertiary phase of oil recovery. To grant industry the opportunity to recover this oil not only means more dollars for Kansas operators, working interest owners, and royalty owners, many of whom are Kansas residents, but it also means employment for field workers and office personnel, and benefits local economies in the small communities in the oil producing counties. It also will add to the tax base of those communities, the counties and the State. Industry feels proposed changes to the statute will enable operators to more efficiently and expeditiously initiate and operate secondary and tertiary projects in Kansas.

I thank you for having the opportunity to present an oil man's opinion of the proposed legislation.

3-7

EXHIBIT A-1

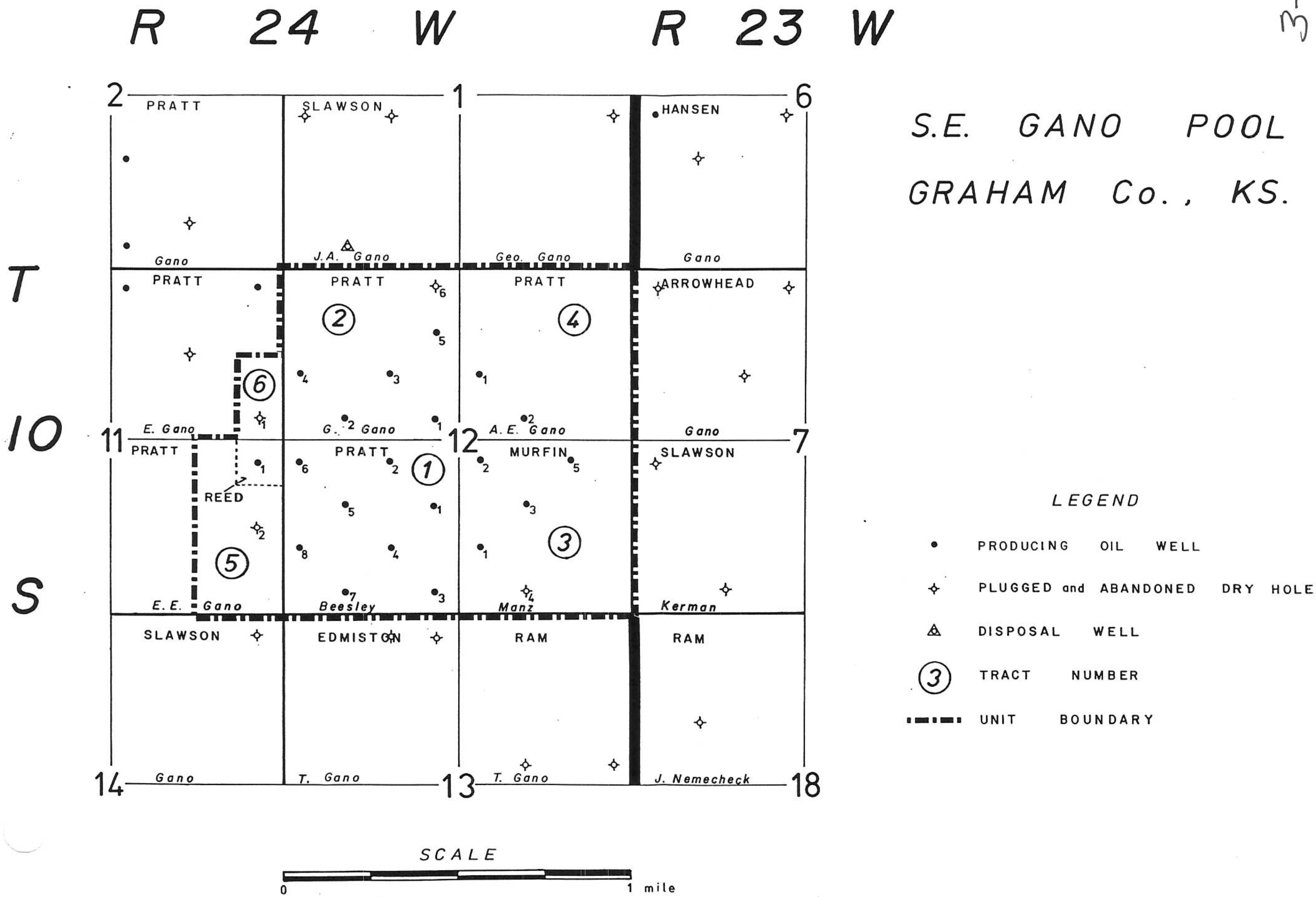
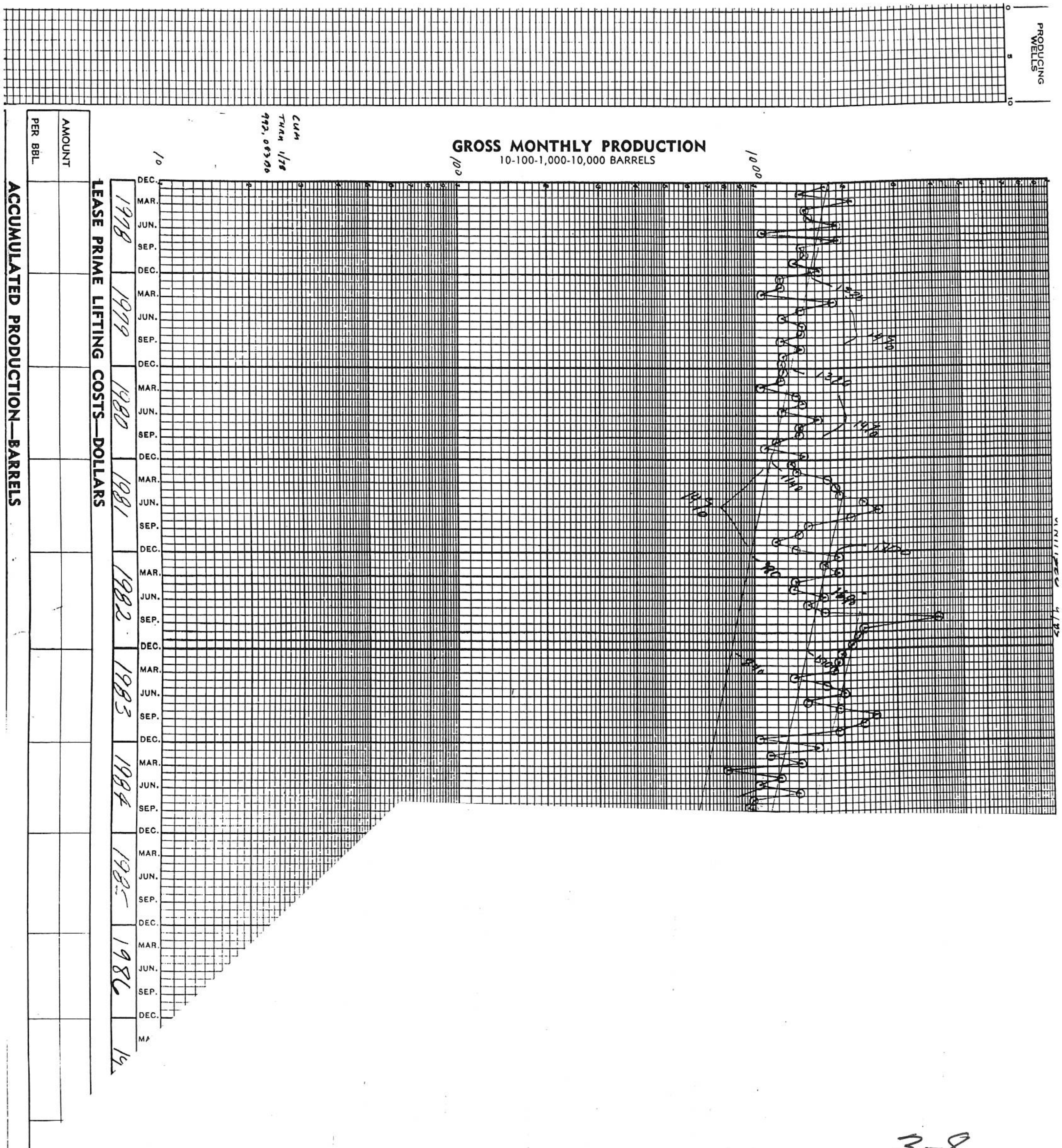


EXHIBIT A-2


PRODUCING WELLS
GROSS MONTHLY PRODUCTION
10-100-1,000-10,000 BARRELS
10
100
1000
LEASE PRIME LIFTING COSTS—DOLLARS
ACCUMULATED PRODUCTION—BARRELS
AMOUNT
PER BBL
1978
1979
1980
1981
1982
1983
1984
1985
1986
DEC.
MAR.
JUN.
SEP.

R 30 W

EXHIBIT B-1

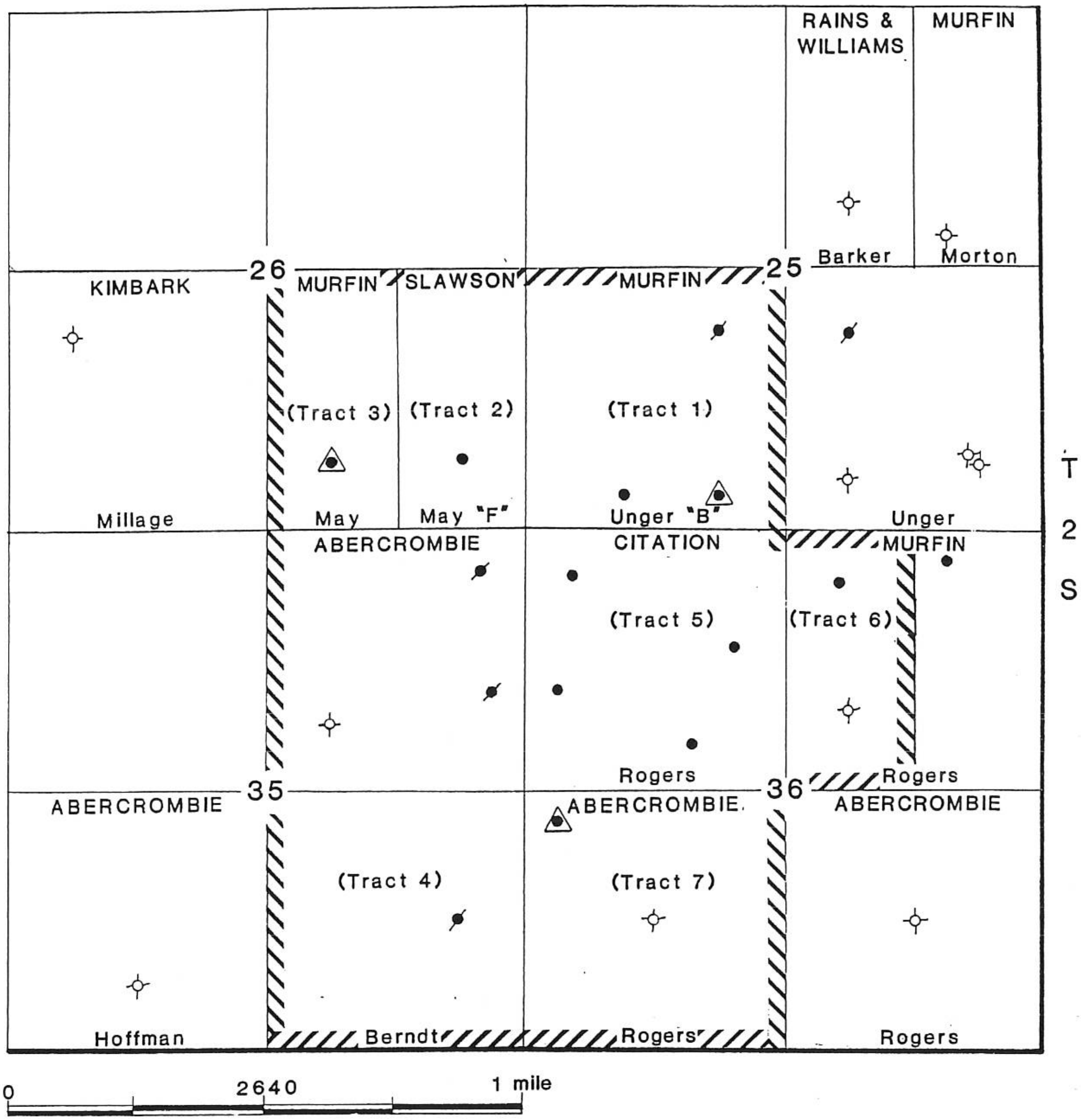


Exhibit "B"

UNG UNIT

Decatur Co., Kansas

Unit Boundary

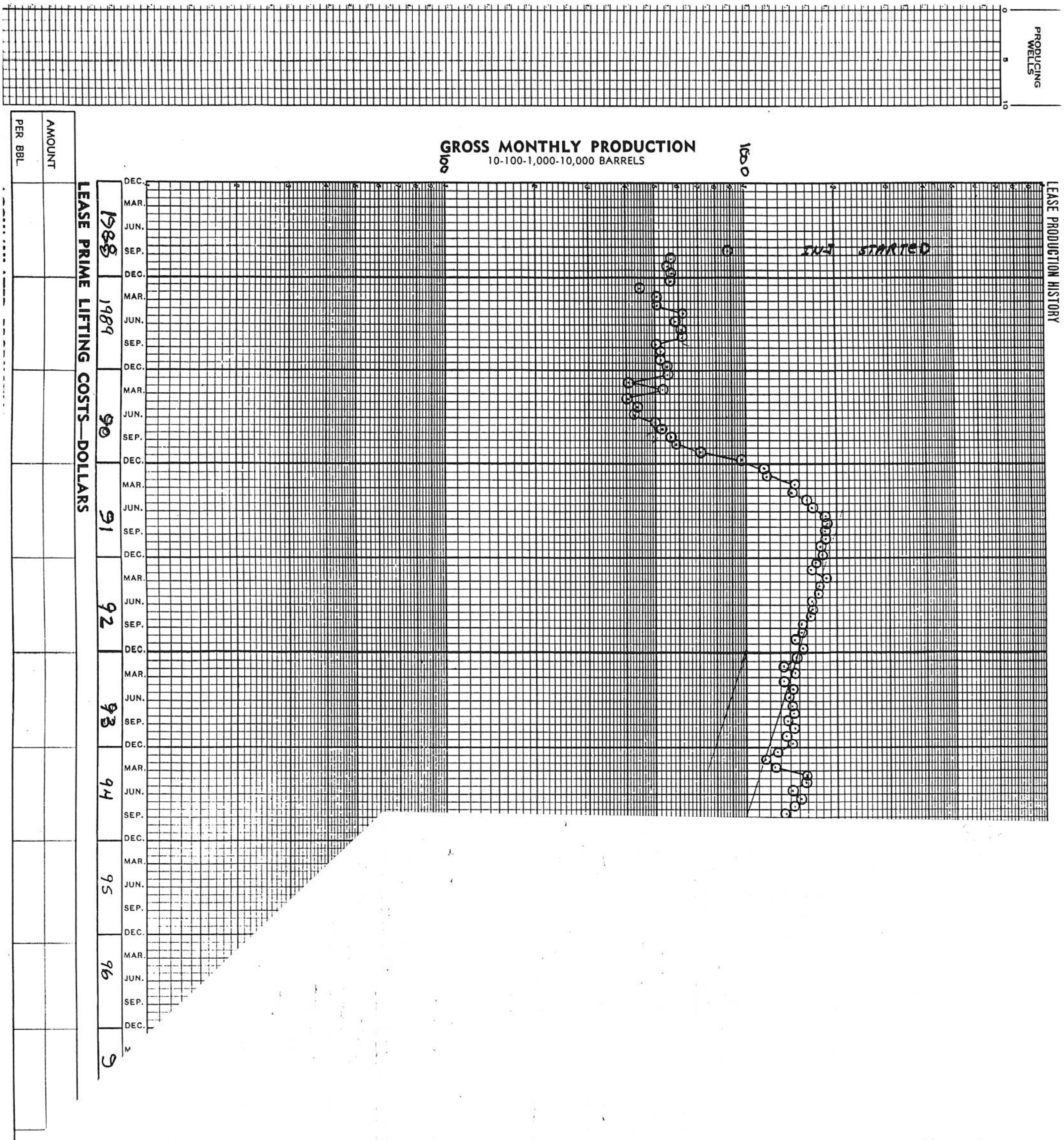
MURFIN DRILLING COMPANY

CONTRACTORS AND PRODUCERS

250 N. WATER SUITE 300, WICHITA, KANSAS 67202

3-9

EXHIBIT B-2



3-10

EXHIBIT C

Executive Summary

Field Demonstration of Carbon Dioxide Miscible Flooding in the Lansing-Kansas City Formation, Central Kansas

PURPOSE OF PROJECT

- Determine the technical and economic feasibility of using CO2 miscible flooding to recover residual and bypassed oil in Lansing-Kansas City of Hall-Gurney field.
- Develop reservoir data for the LKC and Hall-Gurney so that other floods can be performed.
- Develop an understanding of operating costs and operating experience for CO2 miscible flooding in Central Kansas fields.

PROJECT FINANCIAL SUMMARY

Total Project – $5.4 million

- $1.1M – Capital Costs (wells, etc.)
- $0.8M – Operations (6 years)
- $2.0M – CO2 Purchase, transport, recycling
- $1.5M – Research, Technology Transfer

Funding

- $1.9M U.S. Department of Energy
- $1.0M KGS and TORP
- $2.4M Shell CO2 Company and Murfin Drilling Company
- $0.1M Kansas Department of Commerce

OVERALL PROJECT DESCRIPTION

This project is a field demonstration project of carbon dioxide miscible flooding of a Lansing-Kansas City reservoir in the Hall-Gurney field, central Kansas. The proposed field demonstration site is located on the Colliver lease, E/2 SW4 and SE/4 of Sec. 28-14S-13W, and the Carter Lease, NE/4 of Sec. 33-14S-13W. These leases are owned by MV Partners, LP and operated by Murfin Drilling Company. Lansing-Kansas City reservoirs are Class II shallow-shelf carbonates. Carbon dioxide miscible displacement has never been applied in central Kansas reservoirs. The primary challenge in these fields is to implement new recovery technologies before the remaining wells are plugged and abandoned as production reaches the economic limit. The main producibility problem is that the reservoirs have been depleted by effective waterfloods. Production of additional oil requires technologies that can mobilize residual oil left after waterflooding as well as bypassed oil.

The proposed field demonstration project will be a 40 acre six spot with an injection well and five production wells in the Lansing-Kansas City "C" zone. Net thickness of the zone is 12 feet. Average porosity is 25%. Estimated residual oil saturation after waterflooding is about 30%. A new injection well will be drilled, cored, logged, and tested to obtain important data. Other wells will be recompleted in the "C" zone. Five water injection wells will be recompleted to confine the flood. CO2 injection will begin in the second year of the project and alternate slugs of CO2 and water will be injected for a period of 3.6 years. It is planned to inject 0.843 billion cubic feet of CO2 at injection pressures of a minimum of 1300 pounds per square inch (psi). Produced CO2 will be recycled. Full time water injection will begin in the sixth year of the project. Oil recovery has been modeled using the streamtube simulator *CO2 Prophet* to be 75,300 STB (stock tank barrels) at the end of the project. An additional 18,300 STB will be produced economically in the three years following the end of the demonstration project.

The field demonstration will develop reservoir data, flood performance, operating costs and operating experience for carbon dioxide miscible flooding in the Lansing- Kansas City reservoirs in Central Kansas. If the demonstration proves the viability of CO2 flooding in these reservoirs, the project could lead to the construction of a carbon dioxide pipeline into Central

Kansas. Application of this technology in the surrounding Hall-Gurney field could result in additional recovery of 15-21 million barrels of oil (MMBO). On a larger scale, application to other Class II reservoir systems across the entire Central Kansas Uplift could potentially impact production practices for the next two decades and could lead to estimated additional recovery of 600 to 830 MMBO.

COST SHARE

The industry cost share for Budget Period 1 is 55 percent of the total allowable cost, 65 percent of the total allowable cost for Budget Period 2 and 90 percent of the total allowable cost for Budget Period 3. Costs above these are reimbursed by DOE to a maximum reimbursement of $1.9 million. The University of Kansas Center for Research, Inc.(CRINC) is the Prime Contractor. MV Energy, L.L.C. and Shell CO_2 Company, Ltd, the Kansas Geological Survey, and the Tertiary Oil Recovery Project are subcontractors and financial partners in the proposed field demonstration project.

SUMMARY OF ACTIVITIES IN EACH BUDGET PERIOD

Budget Period 1

Activities in Budget Period 1 involve acquisition and consolidation of data into a web-based accessible database (Task 1.1); geologic, petrophysical, and engineering reservoir characterization (Task 1.2) at the proposed demonstration site to understand the reservoir system and develop descriptive and numerical models (Task 1.3) of the reservoir; multiphase numerical flow simulation of oil recovery and prediction of the optimum location for a new injector well based on the numerical reservoir model (Task 1.4); Drilling, sponge coring, logging and testing a new CO2 injection well to obtain better reservoir data (Task 2.1); measurement of residual oil and advanced rock properties for improved reservoir characterization and to address decisions concerning the resource base (Task 2.2); advanced flow simulation based on the data provided by the improved characterization (Task 3.1); and assessment of the condition of existing wellbores, and evaluation of the economics of carbon dioxide flooding based on the improved reservoir characterization, advanced flow simulation, and engineering analyses (Task 3.2).

The development of an adequate reservoir description requires integration of geological interpretation and insight with reservoir engineering analysis. Existing geological and engineering data for the site and from other portions of the Hall-Gurney field will be gathered and placed in a database. Core, cuttings, logs and engineering data will be analyzed to develop a numerical reservoir model suitable for use in reservoir simulation. Because there are no cores from the LKC "C" zone in the immediate vicinity, we will core a new well to determine if there is sufficient residual oil left in the pilot demonstration site to justify a pilot demonstration project (Task 2.1). Laboratory carbon dioxide miscible flooding tests will be conducted on the core to determine the residual oil saturation to carbon dioxide in a miscible environment and to refine rock properties values and correlations (e.g., permeability/porosity) necessary for accurate reservoir modeling (Task 2.2).

At the present time, there are no active wellbores producing only from the LKC "C" zone at the site. After the new well is completed, we will acquire a sample of the LKC oil for verification of MMP as well as to determine reservoir fluids properties for use in reservoir simulation. We must determine if there is potential for enough oil recovery from carbon dioxide miscible displacement to be economically attractive under anticipated oil price and carbon dioxide costs. We will assess the condition of existing production and injection wells carefully to determine to design remediation plans. Based on the results from the advanced reservoir simulation, we will refine the design of proposed carbon dioxide miscible flood. Assuming that all reservoir properties, simulation, and preliminary economics data indicate the flood is viable, a team will review the design of surface facilities and will perform economic analysis of the project. These tasks provide the basis for a recommendation as to whether or not to proceed with implementation in Budget Period 2 (Task 4.1). All of these tasks, carried out in Activities 1 through 4, require close cooperation between all the members of the team.

Budget Period 2

The field demonstration and implementation of the CO2 flood (Activity 5), occurs during Budget Period 2 and consists of five major tasks: (Task 5.1) remediate all wells in the flood pattern; (Task 5.2) re-pressure the pilot area by water injection; (Task 5.3) construct surface facilities; (Task 5.4) implement CO_2 flood operations; and (Task 5.5) analyze CO_2 flooding progress. A multi-disciplinary group will be involved in each activity. In addition to the Kansas CO2 Team, field personnel who will play a significant and critical role in the successful implementation of Activity 5 tasks.

Since all existing wells at the demonstration site have been completed in more zones than just the LKC "C", the project team as well as service company engineers (e.g., Halliburton) must implement a program to isolate the LKC "C" from all other zones. It is tentatively proposed that this will probably involve remedial "squeeze" cementing or the installation of casing liners.

Prior to CO2 flooding the pilot area must be re-pressured to pressures above the MMP. This will be done by water injection into the water injection wells surrounding the producing wells and ultimately designed to contain the CO2. Pressure falloff tests in injection wells will allow estimation of the permeability-feet (kh) of the reservoir at the outer boundaries to refine simulation models. Integration between reservoir and production engineers and field personnel is important to insure proper injection rates and problems with wells in achieving designated rates and pressures.

Before CO_2 flooding can commence, surface facilities must be constructed or upgraded. Field history coupled with reservoir simulation will be used to estimate the volumes and rates of CO_2 and water to be injected into the pilot and the approximate volumes and rates of water, oil, and gas to be produced from the pilot. The simulation may also predict the pilot operating and injection pressures. The reservoir engineers and geologists must communicate this information to the production and facility engineers so that they can properly design the surface equipment. The production and facility engineers will incorporate the experience of the field personnel in equipment design.

Once the CO_2 flood is implemented and is underway, communication between reservoir engineers/geologists and the production engineers and field personnel will be insured by biweekly or monthly conferences and analysis of available data. As will be emphasized several times throughout this proposal, the dissemination of timely and accurate field information is paramount to the success of the CO_2 pilot. Information, such as CO_2 injection rates and which producing wells are responding to CO_2 injection or which producing wells are experiencing CO_2 breakthrough, are critical in the management of the pilot. Oil, gas and water production rates will be monitored using a test separator and computer-controlled monitoring equipment. Injection and individual well production will be adjusted to the reservoir response on a monthly basis.

Budget Period 3

At the beginning of Budget Period 3, carbon dioxide injection ceases and the project is converted to a waterflood. Injection and production data will be collected and analyzed. This data will be modified to refine the reservoir model and improve the numerical flow simulation and and our capability to predict oil recovery from carbon dioxide miscible flooding. Monitoring and analyses activities in Budget Period 3 will be directed toward assessing the potential of carbon dioxide miscible flooding when extended fieldwide and to other LKC reservoirs in Central Kansas. A final economic analysis will be made for the entire project.

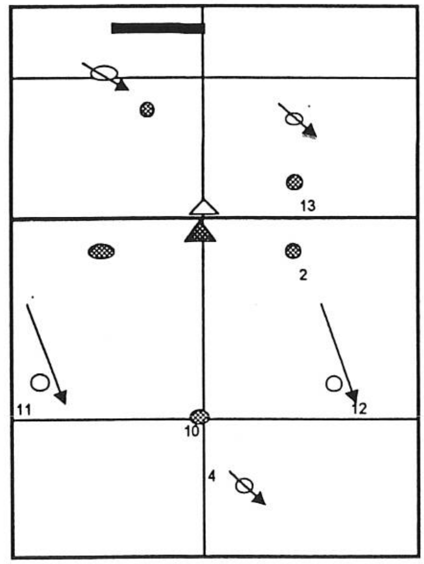
In Budget Period 3 we will assess the potential application of carbon dioxide miscible flooding to the entire Hall Gurney Field. This activity will provide support for the development of a major carbon dioxide pipeline into Central Kansas that could deliver carbon dioxide at prices comparable to those in West Texas.

Executive Summary

Outline for DOE Class 2 Revistied Technical Pilot

Murfin Colliver-Carter Leases
40 Acre, Six-Spot, Sec 28,33-14S-13W, Russell Co., Kansas

Prepared by: Kansas CO2 Team



Demo Project: 40 Acre, Six-Spot
One CO2 injector
.843 BCF CO2 injected
Five Producers
Five Containment Injectors
4.6 year operating life
Estimated recovery 75,300 BO
(additional 18,300 BO in 3 years after DOE)

Costs:		***($M)***	**Subtotal**
	Capital		
(BP-1)	Drill, sponge core, complete, test CO2 Injector	$213.2	
(BP-1)	Plug #18	$23.0	
(BP-2)	Rework and upgrade wells	$474.5	
(BP-2)	Surface facilities	$322.6	
(BP-2)	Drill and Equip WaterSupply Well	$35.0	$1,068
	Operations		
(BP-2)	Repressure Reservoir (0.3years)	$16.4	
(BP-2)	CO2 Slug, WAG (3.7 years)	$654.4	
(BP-3)	Post waterflood (1 year)	$98.1	$769
	CO2		
(BP-2)	Purchase 0.536BCF@$3/mcf	$1,608.9	
(BP-2)	Recycled 0.307BCF @$1.35/mcf	$414.0	$2,023
	Research, Data, Admin, Tech Transfer		
(BP-1,2,3,)	Operator	$82.7	
(BP-1,2,3)	KUERC	$1,470.4	$1,553
	Total	**$5,413.2**	

		Budget Period 1	Budget Period 2				Budget Period 3	Total
Costs	***Purpose of Support***	FY00	FY01	FY02	FY03	FY04	FY05	
Capital Equip.		$236.180	$832.075	$0.000	$0.000	$0.000	$0.000	$1,068.255
Lease Oper. Exp.		$0.000	$137.415	$178.836	$173.773	$180.724	$98.105	$768.853
Operator		$60.000	$4.706	$4.894	$5.090	$5.294	$2.753	$82.737
KUERC		$467.634	$195.378	$234.017	$190.596	$196.121	$186.673	$1,470.418
CO2 costs		$0.000	$810.000	$434.520	$404.894	$373.523	$0.000	$2,022.937
		$763.814	$1,979.574	$852.267	$774.353	$755.663	$287.531	**$5,413.200**
Contributors								
DOE-rate		*$0.450*	*$0.350*	*$0.350*	*$0.350*	*$0.350*	*$0.100*	
DOE	(Research, Technology Transfer, CO2 Transport)	$343.716	$692.851	$298.293	$271.023	$264.482	$28.753	$1,899.119
KUERC	(Research, Data Collection, Technology Transfer)	$257.199	$126.995	$152.111	$123.890	$127.479	$168.005	$955.679
State of KS	(Research Well)	$100.000	$0.000	$0.000	$0.000	$0.000	$0.000	$100.000
Operator	(Lease Facilities and Operation of Flood)	$62.900	$366.292	$110.300	$102.726	$97.410	$90.773	$830.400
Shell CO2-CO2	(Cost of CO2)	$0.000	$130.500	$51.000	$47.095	$39.553	$0.000	$268.148
Shell CO2 Co.	(Shortfall for CO2 Transport and Operations)	$0.000	$662.936	$240.563	$229.618	$226.739	$0.000	$1,359.857
		$763.815	$1,979.574	$852.267	$774.353	$755.663	$287.531	**$5,413.201**

Scope of Project:	$420.099	$1,286.723	$553.973	$503.329	$491.181	$258.778	$4,361.855

Budget Period 1: Detail reservoir characterization, simulation model, drill and core new injection well.
(1 year) Injectivity testing, refine Sor. Refine site selection.

Budget Period 2: Upgrade wells and install facilities. Repressure reservoir (.3yrs) CO2 slug and CO2/Water WAG (3.6yrs)
(4.0 years)

Budget Period 3: Post CO2 waterflood. Finish technology transfer.
(1 year)

Note:
Operator contributes $60M in BP-1 plus $~10/gross BO
BP-2 oil = 64 MBO, BP-3 = 11 MBO)
Shell CO2 Total= *$1,628*
DOE average= *35.1%*

FY 2000-2005 DOE--Total Murfin/Shell/KSDC	BP1	Budget Period 2				BP3	Total
	FY2000	FY2001	FY2002	FY2003	FY2004	FY2005	
Labor	$60,000	$18,824	$19,577	$20,360	$21,175	$11,011	$150,947
Material Equipment	$48,240	$485,382	$0	$0	$0	$0	$533,622
Material-Bulk	$0	$174,000	$51,000	$47,095	$39,553	$0	$311,648
Material-Other	$187,940	$1,105,990	$547,653	$516,308	$498,791	$89,847	$2,946,529
Totals	$296,180	$1,784,196	$618,230	$583,763	$559,518	$100,858	$3,942,745
Total-BP	$296,180		$3,545,707			$100,858	$3,942,745
DOE Cost	$133,281	$624,469	$216,381	$204,317	$195,831	$10,086	$1,384,364
State of KS	$100,000	$0	$0	$0	$0	$0	$100,000
Shell CO2-CO2	$0	$130,500	$51,000	$47,095	$39,553	$0	$268,148
Shell CO2 Co.	$0	$662,936	$240,563	$229,618	$226,739	$0	$1,359,857

Budget Period 1(FY2000)	Task 5	Task 16	Total	Match Cost ($)	DOE Cost ($)
Labor		60000	60000	33000	27000
Material Equipment	48240		48240	26532	21708
Material-Bulk			0	0	0
Material-Other	187940		187940	103367	84573
Totals	236180	60000	296180	162899	133281

Budget Period 2(FY2001)	Task 10 WSW	Task 10	Task 11	Task 12	Task 13	Task 16	Total	Match Cost ($)	DOE Cost ($)
Labor					14118	4706	18824	12235.6	6588.4
Material Equipment	16000	216900		252482			485382	315498.3	169883.7
Material-Bulk		43500			130500		174000	113100	60900
Material-Other	19000	214100	16377	70093	786420		1105990	718893.5	387096.5
Totals	35000	474500	16377	322575	931038	4706	1784196	1159727	624468.6

Note: Water Supply Well is not included in Task 10 budget.

Budget Period 2(FY2002)	Task 13	Task 16	Total	Match Cost ($)	DOE Cost ($)
Labor	14683	4894	19577	12725.05	6851.95
Material Equipment			0	0	0
Material-Bulk	51000		51000	33150	17850
Material-Other	547653		547653	355974.5	191678.6
Totals	613336	4894	618230	401849.5	216380.5

15
3-~~12~~

Budget Period 2(FY2003)	Task 13	Task 16	Total	Match Cost ($)	DOE Cost ($)
Labor	15270	5090	20360	13234	7126
Material Equipment			0	0	0
Material-Bulk	47095		47095	30611.75	16483.25
Material-Other	516308		516308	335600.2	180707.8
Totals	578673	5090	583763	379446	204317.1

Budget Period 2(FY2004)	Task 13	Task 16	Total	Match Cost ($)	DOE Cost ($)
Labor	15881	5294	21175	13763.75	7411.25
Material Equipment			0	0	0
Material-Bulk	39552.5		39552.5	25709.13	13843.38
Material-Other	498790.5		498790.5	324213.8	174576.7
Totals	554224	5294	559518	363686.7	195831.3

Budget Period 3(FY2005)	Task 13	Task 16	Total	Match Cost ($)	DOE Cost ($)
Labor	8258	2753	11011	9909.9	1101.1
Material Equipment			0	0	0
Material-Bulk			0	0	0
Material-Other	89847		89847	80862.3	8984.7
Totals	98105	2753	100858	90772.2	10085.8

17 #-38

Attachment D											
									Other	Total	Comments
									(installation)		
									$0		
									$1,950		
									$8,300		
		Production &	7200	2" Star Fiberglass	API - 800 psi	$4.00	$28,800	$21,600	$7,200		
		Gas Gathering		2 Lines to each well in same ditch Installed							
				Fittings/flanges			$5,000	$5,000	$0		
								$26,600	$17,450	$44,050	
							(X1.15)	**$30,590.00**	**$20,067.50**	**$50,657.50**	
CO2 INJECTION AND RECOVERY SYSTEMS								(equipment)	(site work)		
Task 5.3..4	CO2 Inj. System	Receiving Site	Pad and equipment for managing leased injection equipment				$10,000	$4,000	$6,000		
			Truck to pumps				$0				No facilities costs, Floco bid includes facilities
			Injection pump				$0				
			Temp. modifcation & reg. Equip.				$0				
	CO2 Reinjection	Glycol unit & Compressor to be rented									
		500 MSCFD 3-stage w/ 100 psig suction & 1750 psig discharge									
				Pad and Misc. non-recoverable facilities			$40,000	$34,000	$6,000		These are soft numbers that need to be firmed
				Operating expense							Estimate $4,000/month
				Electricity cost ($0.07 kw/hr)							Estimate $0.44/mcf
				Above Ground Storage Processing and Facilities							Estimated $0.10/mcf
								$38,000	$12,000	$50,000	
							(X1.15)	**$43,700.00**	**$13,800.00**	**$57,500.00**	
MEASURING EQUIPMENT AND DATA GATHERING SYSTEMS								(equipment)	(installation)		
Task 5.3.3	Test Separator	Includes well manifolds, turbine & Barton meters,			Carbon stl CO2 coating		$40,000	$37,000	$3,000		
		maually operated controlers			120 - 250 psig rated						
	Eletronic data gathering and distribution system						$35,000	$30,000	$5,000		
								$67,000	$8,000	$75,000	
							(X1.15)	**$77,050.00**	**$9,200.00**	**$86,250.00**	
PRODUCTION AND WATER INJECTION FACILITIES								(equipment)	(installation)		
Task 5.3.1	Prod. Fluid	Separator	2-phase w/ CO2 coating		250 psig rated	$10,000.00	$20,000	$18,000	$2,000		
	Handling	Two tank batteris, new grades, good used equipment, coated and coated fittings as re					$30,000	$27,000	$3,000		
	Water Injection	Move to centralized facilities					$20,000	$2,000	$18,000		
			Suction tank				$0				Use existing
			Water injection pump system				$0				
			Water makeup system				$0				
	Wellhead and	Producers	Wellhead equipment								
	Downhole			Upgrade Prod. Wellheads & Stuffing Boxes			$0				Included in OWWO costs. Need wellhead equipment rated to 1000
			High Press. Chem. Pumps (5)			$1,000.00	$5,000	$4,500	$500		
			Pump, rods and tubing				$0				Use existing equipment
		Injectors	Wellhead equipment				$0				Included in OWWO costs
		CO2 Inj					$0				Included in CO2 bid
								$51,500	$23,500	$75,000	
							(X1.15)	**$59,225.00**	**$27,025.00**	**$86,250.00**	
							$233,800				Sub total
					Contingency	15.00%	*$35,070*				
							$268,870			*$280,658*	Total Equipment (except for that in OWWO costs)

18
3-15

Attachment E

									Misc Rig Time	Squeeze Perfs w/ Cement	Log, Perf, Acidize	Upgrade Rods & Tubing	Upgrade Tubing & Packer	Upgrade Wellhead	Misc. Equip.	Pumping Unit	Retrieve Fish	Total	
									9000		4500	10500		5000	2000			31000	
									9000		4500	10500		5000	2000			31000	
									6000	3500	4500	10500		5000	2000			31500	
	(Includes 10% Equip-Install)Other	76200		5 Producer	2000		13500	2500	9000		4500	10500		5000	2000			49000	
	(Less10% Install) Equipment	96300																	
	Bulk Materials	9000		10 Injector	2000				6000	3000	4500	10500		5000	2000	6000		39000	
		181500			4000	0	13500	2500	39000	6500	22500	52500	0	25000	10000	6000	0		181500
5.1.3	Containment Injector	Collver		9 Plugged	3000	12000	13500	2500	9000		4500		10500	5000	2000			62000	
				10 Injector	2000				6000	3000	4500		10500	5000	2000		6000	39000	
		Carter		11 TA'd Producer	2000				6000	3000	4500		10500	5000	2000			33000	
	(Includes 10% Equip-Install)Other	89200		12 Producer	2000				6000	3000	4500		10500	5000	2000			33000	
	(Less10% Install) Equipment	96300																	
	Bulk Materials	14500		4 Producer	2000				6000	3000	4500		10500	5000	2000			33000	
		200000			11000	12000	13500	2500	33000	12000	22500	0	52500	25000	10000	0	6000		200000
5.1.4	InjectionTesting	40000		***Misc. Additional***	Injection Testing		15000												
		15000			Tracer Surveys		15000												
		55000			Remedial Cement Jobs		15000												
					Rig Time		10000												
					Total		55000												

Attachment F

Summary of Costs for Statement of Work Task 5.4 - Implement CO2 Flood and Task 5.2 - Repressure Pilot, Task 7.2.4 - Operator Management

Task 5.2	***Repressure Phase***		
Containment Injectors	Overhead and Pumping	5,400	
	Other (Recurring and Non-Recurring)	9,000	
Water Supply Well	Overhead and Pumping	975	
	Other (Recurring and Non-Recurring)	2,025	
		17400	
	Escalator Applied	**16,377**	***(Task 5.2)***

		Producers		Containment Injectors		CO2 Injector		
Monthly		CO2 Fl	Post CO2	CO2 Flood	Post CO2	CO2 Flood	Post CO2	WSW
Pumping		125	125	75	0	250	75	100
	District & Overhead	225	225	225	0	225	225	225
Labor		350	350	300	0	475	300	325
Other		1250	850	500	0	725	500	675
Total		1600	1200	800	0	1200	800	1000
	CO2 Mgmt(annual)	5,000						
	CO2 Monitor Flood	15,000						

year	2000	2001	2002	2003	2004	2005	***Avg***
CO2 Oil	1448	1506	1566	1629	1694	1762	1601
Post CO2 Oil	1086	1129	1175	1222	1270	1321	1201
Water Inj	724	753	783	814	847	881	800
CO2 Injector	1086	1129	1175	1222	1270	1321	1201
WSW	905	941	979	1018	1059	1101	1000

2000	2001	2002	2003	2004	2005	
	0.04	Escalator				
1	1.04	1.0816	1.124864	1.1698586	1.2166529	6.63297546
0.905	0.9412	0.978848	1.01800192	1.058722	1.1010709	6.00284279

	Pumper		District &
Murfin Costs	1st Well	2nd well	Overhead
Oil	160	100	225
Injection	60	60	225
WSW	100	100	225
Disposal	40	40	115

Total LOE less CO2 for Project	
LOE Repressure phase	493,927
LOE Operational Phase	16,377
Operator Managemant	22,737
Operator Monitoring	68,210
	601,250

19
3 46

Attachment F

		2000	2001	2002	2003	2004	2005	Total
Escalator Applied	Overhead and Pumping		0	0	0	0		0
	Other (Recurring and Non-Recurring)		0	0	0	0		0
			0	0	0	0		0
Oil Producers	Overhead and Pumping	0	14,000	21,000	21,000	21,000	21,000	98,000
	Other (Recurring and Non-Recurring)	0	50,000	75,000	75,000	75,000	51,000	326,000
								424,000
Escalator Applied	Overhead and Pumping		13,177	20,556	21,378	22,233	23,122	100,466
	Other (Recurring and Non-Recurring)		47,060	73,414	76,350	79,404	56,155	332,383
			60,237	93,969	97,728	101,637	79,277	432,849
CO_2 Injector	Overhead and Pumping	0	3,800	5,700	5,700	5,700	3,600	24,500
	Other (Recurring and Non-Recurring)	0	5,800	6,000	6,000	6,000	6,000	29,800
								54,300
Escalator Applied	Overhead and Pumping		3,577	5,579	5,803	6,035	3,964	24,957
	Other (Recurring and Non-Recurring)		5,459	5,873	6,108	6,352	6,606	30,399
			9,036	11,453	11,911	12,387	10,570	55,356
Water Supply Well	Overhead and Pumping	0	3,575	3,900				7,475
	Other (Recurring and Non-Recurring)	0	7,425	8,100				15,525
								23,000
Escalator Applied	Overhead and Pumping	0	3,365	3,818				7,182
	Other (Recurring and Non-Recurring)	0	6,988	7,929				14,917
			10,353	11,746				22,099
CO_2 Operations Management			5,000	5,000	5,000	5,000	2,500	22,500
CO_2 Operator Monitor Flood			15,000	15,000	15,000	15,000	7,500	67,500
Escalator Applied			4,706	4,894	5,090	5,294	2,753	22,737
			14,118	14,683	15,270	15,881	8,258	68,210
			18,824	19,577	20,360	21,174	11,011	90,946
								591,300
	Overhead and Pumping		20,118	29,953	27,181	28,268	27,086	132,606
	Other (Recurring and Non-Recurring)		59,507	87,215	82,458	85,756	62,761	377,698
	Total Operations		79,626	117,168	109,639	114,024	89,847	510,304
	Less Repressuring LOE		-16,377					
Task 5.4.1			**63,249**	**117,168**	**109,639**	**114,024**	**89,847**	**493,927**
Task 7.2.4	CO_2 Operator Mgmnt		**4,706**	**4,894**	**5,090**	**5,294**	**2,753**	**22,737**
Task 5.4.4	Co2 Operator Monitor Flood		**14,118**	**14,683**	**15,270**	**15,881**	**8,258**	**68,210**
	Total Operator Mgmnt		18,824	19,577	20,360	21,174	11,011	**584,873**
	Grand Total	0	82,073	136,745	129,999	135,199	100,858	
	Year	2000	2001	2002	2003	2004	2005	

Well Operating Expense

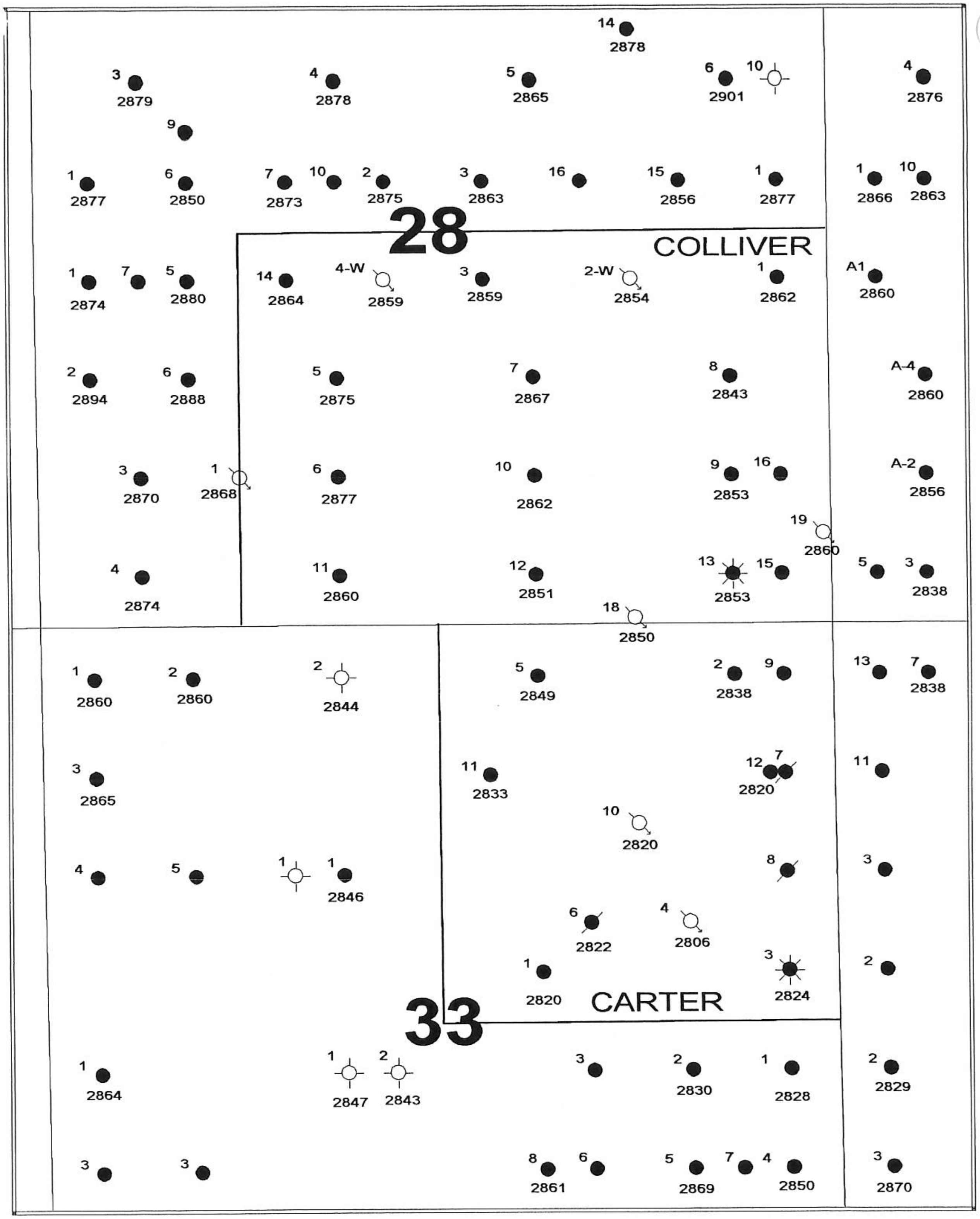
(Monthly)	# Wells	During CO2 inj.	Post CO2	Total Monthly CO2 inj.	Total Monthly Post CO2	
WSW	1	1,000	0	1,000		*1st two years*
Producers	5	1,600	1,200	8,000	6,000	
Injectors	1	1,200	800	1,200	800	
Cont. Inj.	5	800	0	4,000	0	
				14,200	6,800	
Additional oversight and overhead due to CO2				0	0	
				14,200	6,800	

Much higher due to additional chemical costs and higher operating pressures (compared to conventional wf)

2000	0		KUERC
2001	139,000		*OWWO and repressure months1-4, 0.15 HCPV Slug for 0.63yrs begins in month 5*
2002	170,400		*0.30 HCPV WAG 1:1 starting 2002*
2003	170,400		
2004	170,400	650,200	*WAG ends at end of 2004*
2005	81,600	81,600	*Post-CO2 waterflood*
	731,800		

Note: *This will not match the DOE proposal which includes some operator monitoring (13.4) a operator management (16.2.4)*

EXHIBIT D



Murfin Drilling Company, Inc.		
Colliver - Carter CO2 Project Depth to Lansing 14S - 13W Russell County, Kansas		
James R. Daniels	1" = 1000'	02/09/2000
	Scale 1:12000.	