ANETH UNIT RELIABILITY ENGINEERING LEASE REVIEW

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ABSTRACT

Three significant conditions existed in the oil industry in 2000. First we had the best oil prices we had seen in years, second we didn't know how long they were going to last and third many of the major oil companies were investing in overseas growth opportunities leaving less capital for domestic projects. Aggressive operators, with the ability to respond quickly, wanted to take advantage of the high oil prices by increasing production ***(make hay while the sun shines).*** Discerning operators wanted to hedge their spending on projects that would payout before the price fell back. Many major oil companies had to use only "expense" type funding for the short-term production enhancing projects.The Aneth Unit is a 320 well waterflood/CO2 flood in Southeastern Utah. This paper discusses how Reliability Engineering was used on the Aneth Unit to select projects that increased production, paid-out in six months, used no capital funds and required no increase in the annual expense budget. The paper is intended for field engineers, field supervisors and operations technicians. The paper will cover how we assembled a team to define a mission statement that accounted for the uncertain oil prices and the lack of a capital budget. The paper steps us through the Reliability Engineering process of brainstorming for ideas, culling and prioritizing ideas, defining and assigning action items and assessing results. The paper discusses how our prudent spending resulted in increased cash flow, increased earnings, improved return on capital employed, increased production and decreased lifting costs.

DEVELOPMENT AND GEOLOGY

The Aneth Unit of the Greater Aneth Field complex became effective on September 1, 1961 and produces from the Ismay and Desert Creek intervals of the Pennsylvanian Paradox Formation. Both formations are unitized. The Paradox Formation is a heterogeneous carbonate unit. Production from the Ismay is minor compared to the Desert Creek volume and is predominantly from isolated algal mounds with a maximum thickness of twenty to thirty feet. Waterflood operations were initiated in February 1962 utilizing the existing 80-acre spaced wells. Additional drilling in the mid-1970s resulted in reducing the well spacing to 40-acres (80-acre five-spot patterns) in the majority of the Unit. Eight 20-acre spaced wells have been drilled since 1985. In late 1994 a multilateral horizontal drilling program was initiated at the Aneth Unit. The horizontal wells were drilled out of existing vertical wells. Six existing wells were re-entered and horizontally drilled in 1998. A total of 43 vertical wells have been re-entered and horizontally drilled to date. C02 flooding was initiated on part of the Aneth Unit with Phase I startup in 1998. The Phase I project area is located in Sections 11, 13, 14, 15 and 23 of T49S, R24E. The first C02 injection began on October 12, 1998 and by 1999 nine wells were on C02 injection. Currently there are 159 active producing wells and 144 active injection wells in the Unit. Since our plans for 2000 included evaluating the response characteristics of the horizontal C02 flood performance, no new horizontal wells were planned and no C02 expansion was planned for 2000.

FINANCIAL TERMS

Expense and Capital spending classifications are defined by strict Internal Revenue Service (IRS) rules and are taxed differently. Capital is deducted for tax purposes over the life of the project or equipment via Depreciation, Depletion and Amortization (DD&A). Expenses can be deducted in the year spent. Capital is spending to increase reserves and other assets. Expense is spending to exploit existing reserves and assets. Oil companies have separate capital and expense budgets in keeping with tax law. For our discussion, the terms capital and expense will have the same conventional meanings as described above.

INTRODUCTION

Today there exists a unique combination of oil prices and spending budgets for many in the domestic oil industry:First, oil prices have risen to all-time highs. Price ascension started in early 1999 when oil was about $8 per bbl and has risen to current levels of about $30 per bbl.Second, though analysts predicted that the high prices would drop by late 1999, prices have been strong for two years. However, analysts still hold that prices, due to foreign influence, can and will fall in short order. Third, in recent years and for many reasons, an increasing number of oil companies are choosing to invest their capital on foreign growth projects in lieu of domestic projects. This is a deviation from prior years when more capital was spent domestically. Given the recent emphasis on foreign investment, less capital is available for domestic projects. The high oil prices which enable more projects to be justified, entice aggressive operators to increase production. Yet, analysts' uncertainty of the future of oil prices makes discerning operators want to spend only on projects that will payout before prices fall. Capital constraints mean that operators have only the expense budget to increase production.

2000-2001 ANETH UNIT OBJECTIVES

Until 1999, the Aneth Unit emphasized capital spending on building a CO_2 flood, drilling horizontal wells, performing reserve-increasing workovers, etc. As of 2000, as was the case with many domestic projects, Aneth had no capital budget and was forced to operate with only the expense budget. Therefore, the 2000 and 2001 goal for Aneth is to accelerate the production of existing waterflood and CO_2 flood reserves to take advantage of the high oil prices by performing expense type projects that will payout in six months or less. We plan to accomplish our goal using Reliability Engineering Management Methods and termed this goal "Aneth Unit Production Impact Project (AUPIP)". The goal does not address lowering expenses. It addresses increased production by accelerated, upfront spending within the existing expense budget. About half of Aneth's expense budget is discretionary so if the accelerated AUPIP spending starts to go over the budget, it can be slowed to stay on budget. As such, AUPIP presents little risk of overrunning the expense budget. AUPIP is very similar to what a prudent operator would do irrespective of the current oil price environment and capital constraints. AUPIP is different from ordinary operational objectives only in that it requires us to spend early in the year to immediately increase production and enables us to more easily justify spending with the high oil price.

RELIABILITY MANAGEMENT PROCESS

The first step to accomplish our goal was to set a standard by which we could measure our success. Texaco has an annual Tactical Plan (TAC Plan) which establishes annual goals. The TAC Plan defines the production, cash, earnings, lifting costs, Return on Capital Employed (ROCE), Net Present Value (NPV), et cetera that is expected given the allocated budgets and operating plans. These are the financial indicators that stockholders use to evaluate Texaco performance. We used these financial indicators to gauge AUPIP's added value. The second step was to assemble an effective team to decide on activities and timing that would enable us to accomplish the AUPIP goal. Engineers, engineering associates, production technicians and field supervisors that worked on the Aneth Unit were invited. Importantly, service alliance partners were also added to the team since our alliance partners have vested interests in our business. They also bring a profound knowledge of Aneth operations and some unique perspectives. Personnel from Unichem, Axelson, Dowell and Key Energy representing the chemical, rod and pump, stimulation and pulling unit alliance partners respectively were asked to participate. The Reliability Engineering Coordinator was invited to facilitate the initial meeting. Third, after describing AUPIP and ensuring understanding, the group brainstormed activities that they knew could increase production within the context of the current oil price environment and capital constraint. Again, relatively quick increases in production were emphasized. By group decision, projects with risked payouts of six months or less would be approved. Several activities were suggested. The activities were culled, assigned values and prioritized. The final list of activities was as follows:

- Downhole Workovers
- Injection Well Reactivations
- Back Pressure Reduction/Casing-Head Flowlines
- Pump-off-Controller (POC)/Fluid Level Management
- Isolation of Sellable Gas
- Other

Not surprisingly, some of the suggested activities included a re-emphasis on fundamental best practices applicable to any flooding project. For example, it is well established that reducing backpressure can increase production. Other activities were specific to our operation like manifold enhancements to separate sellable and unsellable gas. The point should be taken that the Reliability Engineering Management System prompts us for both fundamental and unique production increasing activities. Fourth, each activity was then assigned a captain to organize implementation efforts. The captains were charged with determining the 1) scope, 2) cost, 3) timing, 4) incremental production, 5) affect on cash, earnings, lifting costs, ROCE, NPV and 6) people and resources needed to accomplish the activity. Fifth, the AUPIP team met again to assimilate the activity data, present the plan to management and discuss the logistics. The captains were individually charged with accomplishing their activities. They were given the resources, authority, responsibility and support to implement their activities. As an indication of their confidence, the captains also agreed to be held accountable for results.

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AUPIP ACTIVITY IMPLEMENTATION
DOWNHOLE WORKOVERS

AUPIP's goal for downhole workovers was to increase wellbore inflow of Aneth's booked secondary and tertiary reserves. The process entailed examining production curves and Hall plots on every well to diagnose skin damage (Figures 1 and 2 are examples of the curves analyzed). The wells were examined for acceptable injection-withdrawal-ratios (IWR) and proper conformance using pattern curves and completion cross-sectional maps (Figure 3). Wells that simply had skin damage were tagged for fill, cleaned out and acidized. Patterns that showed poor conformance were completed into new zones and/or cement-squeezed in selected zones to insure that pattern injectors and producers were completed in only productive congruent zones. Again, all work that would payout in six months or less was approved. Focused efforts enabled AUPIP to complete identified workovers in five months. Downhole workovers yielded the following results:

Expense	$483,000
Incremental Production	650 BOPD
Payout	2.4 months
NPV	$4.9MM

AUPIP ACTIVITY IMPLEMENTATION
INJECTION WELL REACTIVATIONS

Prior to the onset of CO_2 operations, pattern injectivity and water production were fairly well balanced. However, if a pattern experienced a temporary reduction in injectivity resulting from an injection well failure, the balance was upset. When the balance was upset, some water production and its associated oil had to be shut-in to prevent injection tank overflows. With the onset of CO_2 flooding, water injection was alternated with gas injection (WAGed) in the CO_2 pilot area to take advantage of water's more favorable mobility ratio and increase the CO_2's lateral sweep efficiency. Thus the onset of CO_2 upset the injectivity/produced water balance while injection wells were on the CO_2 cycle. With the onset of CO_2, oil production associated with shutting-in water rose to 75 BOPD. The AUPIP team recognized that there were several injection wells around the fringes of the Aneth Unit that had been temporarily abandoned (TA'd) prior to CO_2 implementation. Records indicated that they had good injectivity but were TA'd because they affected no response in offset producing wells. Cross-sections showed that these injection wells were not contiguous with offset producers. As such, injected water was never evidenced in offsets by either oil or water production. These fringe TA'd injection wells were deemed ideal sinks with which to increase Aneth's injectivity during the CO_2 WAG cycles. Activating the temporarily abandoned wells provided needed sinks, averted shutting-in production wells during injectivity reducing events and did not recycle injected water. Once identified, reactivations were accomplished in three months. The reactivations served to avert 75 BOPD from being shut-in and yielded the following:

Expense	$14,000
Incremental Production	75 BOPD
Payout	**1.2** months
NPV	$272 M

AUPIP ACTIVITY IMPLEMENTATION
BACK PRESSURE REDUCTION/CASING-HEAD FLOWLINES

All produced oil, water and CO_2-contaminated gas from the CO_2 pilot area first enters a manifold to isolate fluids for measurement. The manifold isolates one well for testing. After passing through the test separator and meters, the production from the well being tested is recombined with all other wells' production and sent to the central recycling plant. The stream enters a vertical separator where the free gas is separated and sent to the compressor facility for recycling. The liquid stream passes through a Magnetic Flow Meter (MAG) that measures the oil, water and pressure. The pressure at the Mag Meter is the separator pressure. The liquid stream then goes to a horizontal separator where oil and water are separated (Figure 4). The separated oil is sold and the water is sent to the water injection plant for re-injection.

The central recycle plant, with its liquid and pressure measurement capabilities, affords the means to calculate a productivity index (PI) representative of all 22 producing wells entering the facility. Mag Meter volumes and pressures (graphed on Figure 5) show a PI of 60. That is, it showed that production increased by 60 barrels of total fluid per day (BTFPD) for every one-psi pressure drop. This data was then applied to specific wells within the CO_2 pilot area that had high volume production and high backpressure.

CO_2 response in some of these high volume wells made gas production go up by 1000%. Flowlines were not sized for the increased production and friction caused flowline pressures to increase up to 600 psi (as shown on Figure 6). Calculations using the central recycle plant's productivity index and these wells' oil/water ratios (OWR) indicated that an incremental 40 BOPD could be realized by reducing the backpressure to 200 psi.

Therefore, the objective was to reduce flowline pressure to allow better wellbore inflow performance. Computer simulation indicated that the trade-off between higher back pressure and more of the reservoir being above miscibility pressure vs. less back pressure favored less back pressure for more oil production within our pressure ranges.

The solution was to install an additional flowline coming off the annulus between the casing and the tubing (as shown on Figure 7). This was done in lieu of replacing the existing flowline with larger pipe. In addition to increasing the effective cross-sectional area of the flowline and reducing friction, the additional flowline also served to separate fluid flow. Gas was now produced through the casing flowline and liquid was produced out the tubing. Single-phase flow in the separate flowlines further served to reduce flowline pressure. Adding the annulus had a net affect of reducing pressure by 440 psi. This work to reduce backpressure yielded the following results:

Expense	$30,000
Incremental Production	40 BOPD
Payout	2.4 months
NPV	$333M

AUPIP ACTIVITY IMPLEMENTATION
PUMP-OFF-CONTROLLERS (POC)/ FLUID LEVEL MANAGEMENT

Every pumping unit well on the Aneth Unit is controlled with a Pump-Off-Controller (POC). These POCs automatically log time on and time pumped-off. The POCs have strain gauges mounted on the polished rod for direct dynamometer calculations. The dynamometer cards drawn by the POCs have been verified with independent dynamometer and fluid level (FL) measurements. As such, Texaco has confidence that the cards are accurate. The cards are used for rod stress, pump analyses and for setting pump-off points. Adherence to the API recommended practices shown below has held the pumping well failure rate at Aneth to an acceptable .4 failures per well-year.

API RP 11L Recommended Practice for Design Calculations for Sucker Rod Pumping Systems
API RP 11AR Recommended Practice for Care and Use of Subsurface Pumps
API RP 11AX Specification for Subsurface Sucker Rod Pumps and Fittings
API RP 11B Specification for Sucker Rods
API RP 11BR Recommended Practice for Care and Handling of Sucker Rods

Texaco's goal on the Aneth Unit is to pump-off every well at least once per day. However, a certain percentage of the wells were pumping 24 hours per day which indicated that they were maintaining a high fluid level. Productivity Indices applied to these wells indicated that pumping the wells off could produce an additional 100 BOPD and 1200 BWPD. The added injection capacity at Aneth, by virtue of reactivating injection wells, enabled the Aneth Unit to handle the additional water.

The objective then was to increase the capacity of the pumping units on these wells that were not pumping-off without exceeding the equipment tolerances. The existing pumping units and rods were arguably at maximum mechanical tolerances for stroke length, strokes per minute and pump bore diameter. **Also,** the rod pumps were at 75-90% efficiency. The largest available pumping units available were already on these non-pumped-off wells, and the wells already contained the most efficient rod tapers. Purchasing new pumping units and/or rods was a capital expenditure and would not payout in six months or less. Therefore, upsizing the pumping unit and/or equipping the wells with different rod tapers was not an option.

Tests using a differently configured rod pump on CO_2 wells, the Flowmore Pump, showed that the Flowmore enabled us to increase the stroke speed or the stroke length and pump at higher efficiencies without increasing the load on rods and pumping equipment. The tests showed that the Flowmore could be used to increase production and stay within API tolerances. Flowmore Pumps utilize a 1" pull-rod in lieu of the ¾" pull-rods making the pump more stress tolerant. Flowmores utilize a Texas pattern ball and seat which is simply a larger seat for the given ball diameter thus increasing the cross-sectional area of the seat and reducing friction. The cage is spiral-shaped to promote laminar flow thus inhibiting gas breakout and the pressure drop of turbulent flow. Inverting the standing valves on these pumps added compression and made the pumps even more efficient and more capable of handling gas production.

It was found that several of these high FL wells had pumping units with an additional crank-arm hole to increase the stroke length. However these holes were worn beyond use. A machine company was contracted to ream and sleeve the holes to enable their use so that the stroke length could be increased. Increasing the stroke length and utilizing the Flowmore Pumps enabled us to pump the wells off. Increasing the capacity and efficiency of rod-pumped wells while staying within API mechanical tolerances yielded the following results:

Expense	$20,000
Incremental Production	100 BOPD
Payout	2 months
NPV	$1.1 MM

AUPIP ACTIVITY IMPLEMENTATION
ISOLATION OF SELLABLE GAS

Two satellite stations gather and test gas in the CO_2 pilot area via test manifold systems. Normally the gas would be sold through meter runs existing at these stations. With response to CO_2, some wells started producing high CO_2-content gas. The high CO_2-content gas was not marketable and was recycled into the reservoir. Wells that had not yet responded to CO_2 still had marketable gas. However, satellite station design was such that the marketable and unmarketable gas were combined in manifolds (as shown in Figure 8). Combining the gases rendered all the gas unmarketable, therefore all the gas was recycled. The objective was to keep the marketable and unmarketable gas streams separate to increase gas sales and reduce the load on the recycle compressor. Adaptations to the satellite station manifold were made to isolate the pure and contaminated gas streams (as shown in Figure 9). Uncontaminated gas could therefore be sold, as was the practice prior to CO_2 injection, and the CO_2-contaminated gas could recycled. The results of re-piping the test manifold and isolating the pure gas from the contaminated gas are as follows:

Expense	$5,000
Incremental Production	60 BOEPD
Payout	1.5 months
NPV	$598 M

AUPIP ACTIVITY IMPLEMENTATION
OTHER

The following other activities were identified and targeted to increase production:

A five-spot 80-acre injection pattern was completed by converting producer No. F115 to injection. The conversion provided needed injection pressure support to this pattern.

CO_2 injection wells were killed with mud for workovers instead of shutting-in the wells and waiting for the pressure to dissipate before being worked over. Lost production associated with downtime waiting for pressure to dissipate outweighed the incremental expense of using mud.

A program to clean injection riser screens was implemented to increase injection rates on wells that had reduced injection due to partially plugged screens.

Tubing and rod stocks were purchased and stored at the Aneth Unit rather than buying tubing and rods on an as needed basis when a well failed. Having tubing and rods on stock, rather than waiting for deliveries, reduced the workover turnaround time and averted downtime lost production.

A roustabout crew was contracted to supplement company personnel to shorten the time to repair failures that were causing lost production. The cumulative affect of these Other activities is as follows:

Expense	$154,000
Incremental Production	161 BOPD
Payout	9 months
NPV	$1.0 MM

SUMMARY

The cumulative Expense, Net Present Value and payout of Aneth Unit Production Impact Project (AUPIP) are $483,000. $4.9 MM, and 2.4 months respectively:

Expense	$483,000
Incremental Production	650 BOPDNormalized
Payout	2.4 months
Net Present Value	$4.9 MM

Graph 1 shows that AUPIP will increase production by *650* BOPD which constitutes a 14% increase over base TAC Plan. The same graph shows the incremental production associated with each AUPIP activity.

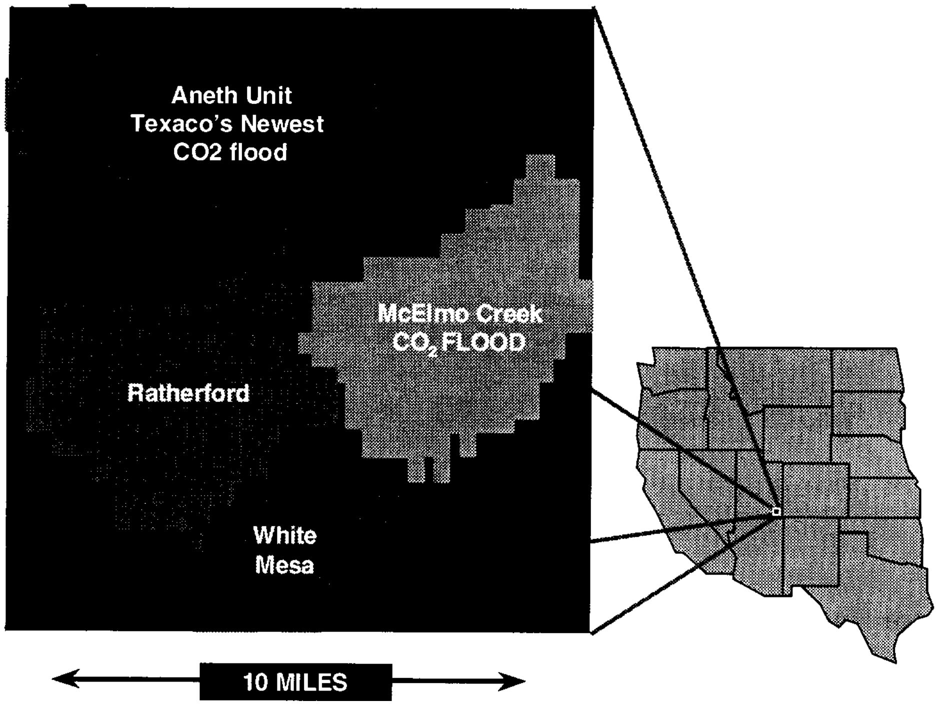
Graph 2 shows that the ROCE will increase by 20% due to AUPIP's increased production

Graph 3 shows that cash and earnings will increase by $900,000 from AUPIP.

Graph 4 shows that lifting costs will decrease from $5.17/BO to $4.90/BO (Note that increased oil prices are not used in lifting-cost calculations. Lifting-costs are purely a result of the increased production associated with AUPIP).

The conditions in which all businesses must operate are continuously changing, especially in the domestic oil industry. The changes may be economical and financial, like on the Aneth Unit, or any combination of potential changes such as regulatory, environmental, technological, ownership, etc. All these changes are analogous in that they require us to recognize that change is inevitable and in that they require appropriate attention. It makes sense therefore to have a process in place to deal with change. The Reliability Engineering is just such a process. Reliability Engineering entails clarifying the operating environment and boundaries, assembling a team, defining the objectives, brainstorming activities, trusting the input of team members, assigning actions, empowering leaders, defining the reference by which success will be measured and providing the resources and support. The Reliability Engineering process is equally applicable whether you are trying to take advantage of the high oil prices on the Aneth Unit or managing a large business entity with a multitude of changes and circumstances.

ANETH FIELD, S.E. UTAH



Producer E217

10/21/99 rod
5/12/99 rod
5/19/98 pmp

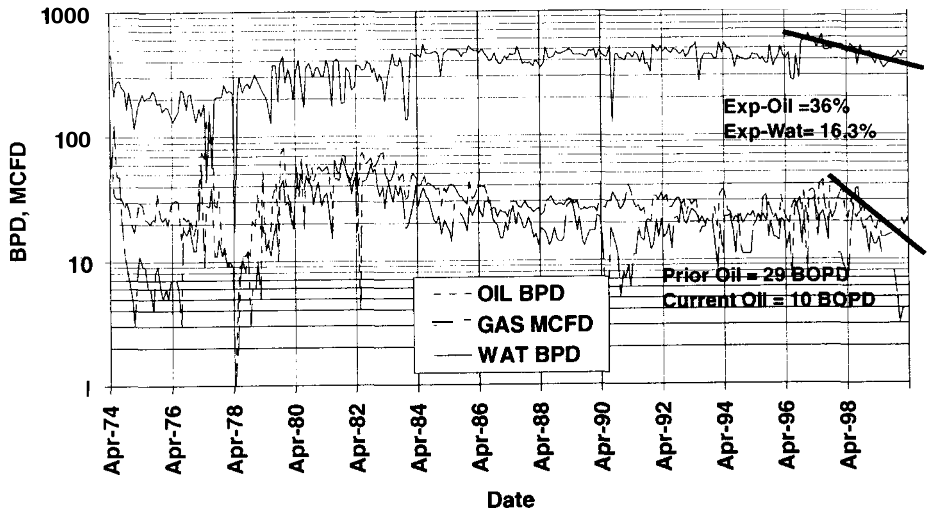


Figure 1

Injector E407

- Interior Injector
- Steady pressure at 2340 psi
- Declining injection rate may be hurting production from indirect offset F307
- Decline not due to downtime/failures
- Risked potential injection increase is 75 BWIPD
- With IWR of 15:1, offset production potential is 5 BOPD.
- Tag, C/O & Acid expense is $20,000.
- NWI payout is 6.3 months.

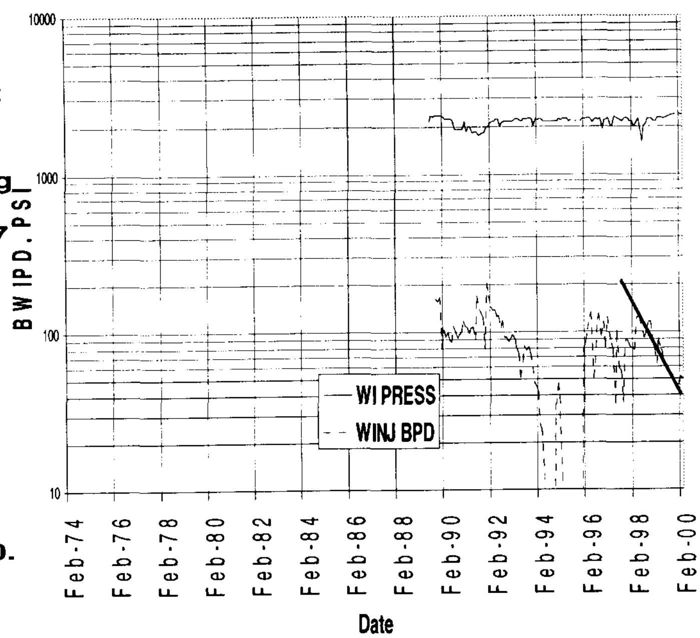


Figure 2

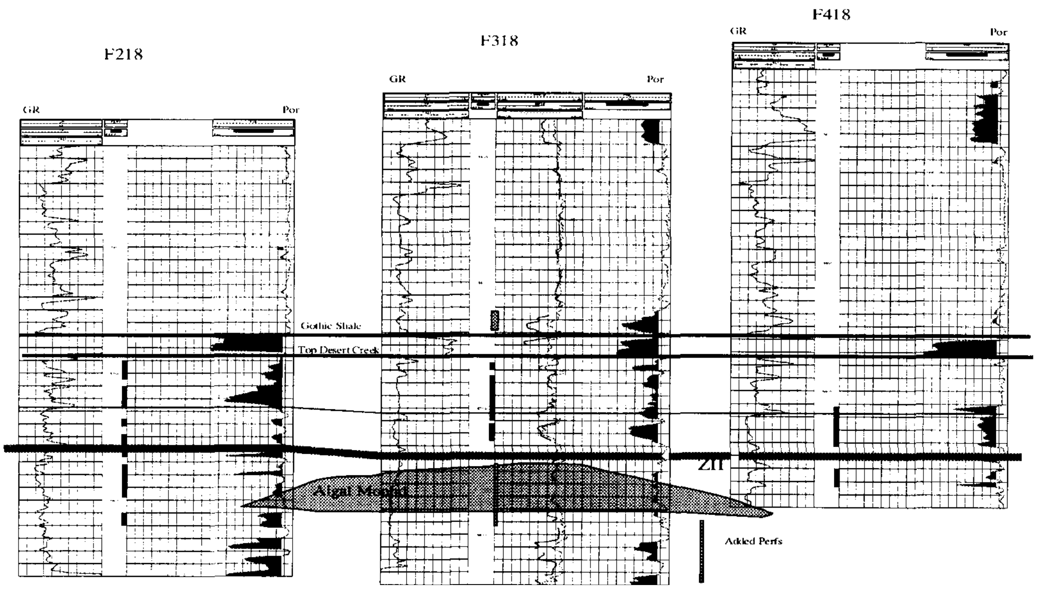


Figure 3

Aneth Unit C02 Facility

Location of experimental Mag meter

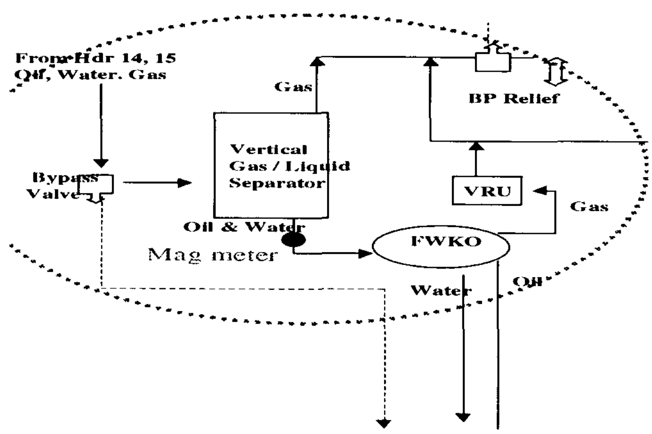
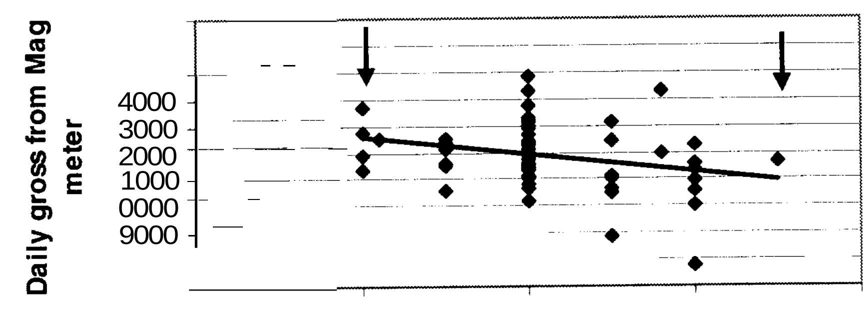


Figure 4



PSI of Vertical Seperator

25 psi = 11,000 BGPD
00 psi = 12,500 BGPD

Date	FWKO PSI	Vert Sep PSI	Rosemount Total
ast rdg.			
1	55	105	10585
2	50	100	11339
3	75	115	11047
4	50	110	11364
5	52	110	10170
6	62	120	10000
7	65	120	12306
8	65	125	11644
9	65	110	13092

Field Data

Figure **5**

F411 Producer

Before: When CO_2 response made gas production go up X 10,

the flow line was undersized and pressure against the formation was too high

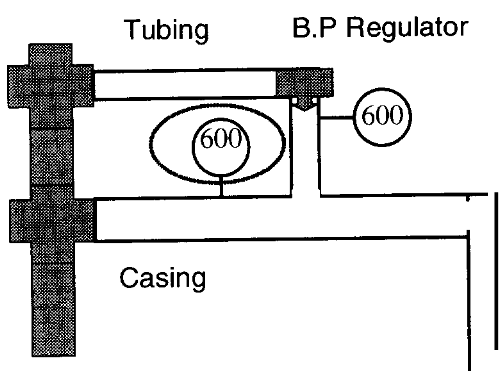


Figure 6

F411 Producer
After: New flow line added to existing flow line decreased back pressure on the formation by 440 psi

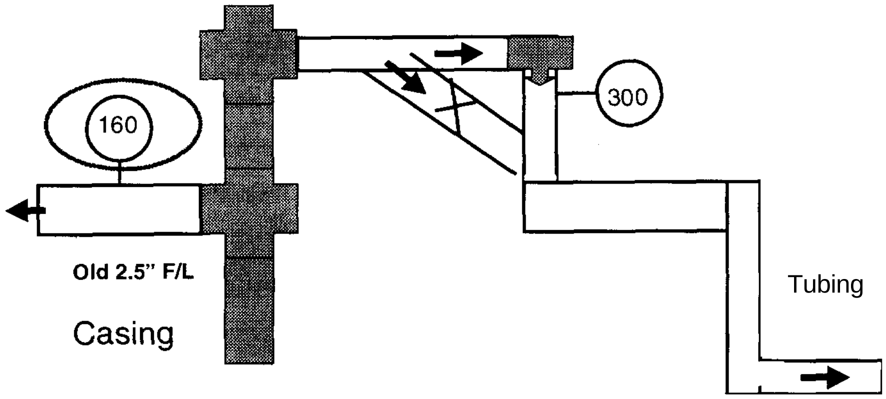


Figure 7

Before: Wells with and without CO2 contamination are all going to the CO2 plant

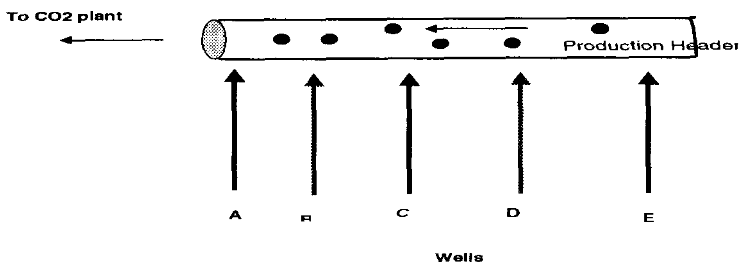


Figure 8

After: Contaminated and Non contaminated well flow lines are moved. Installed an isolation valve
Result = Partial gas sales resumed.

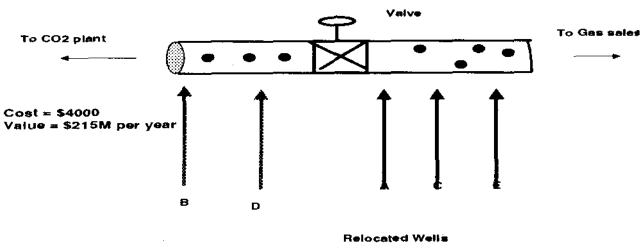
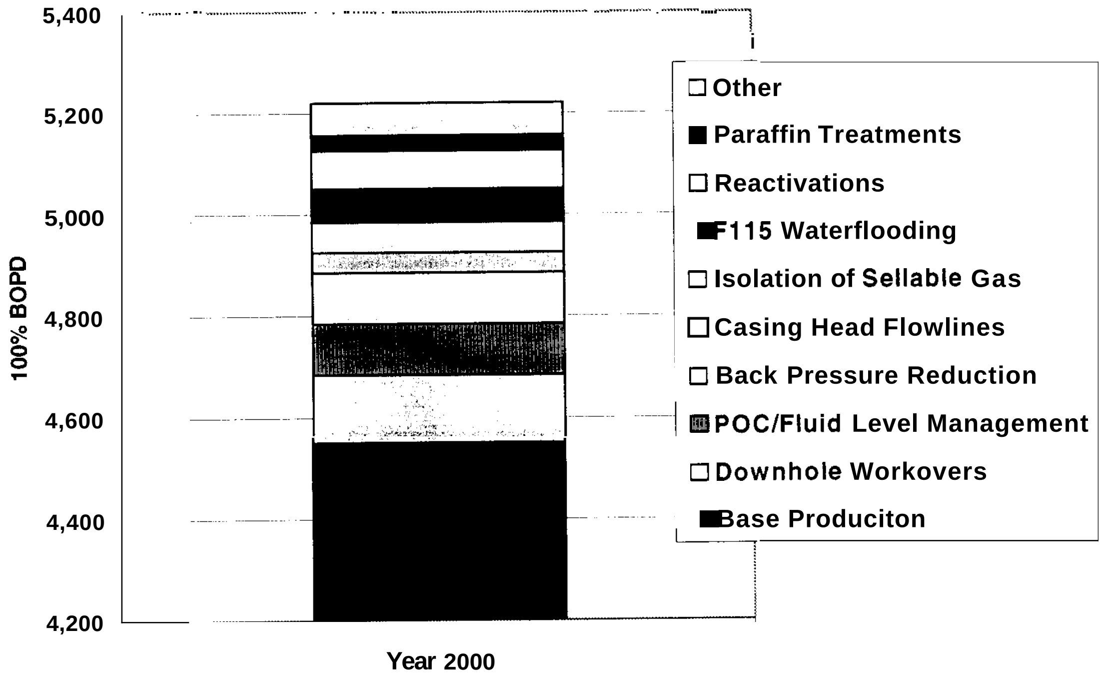
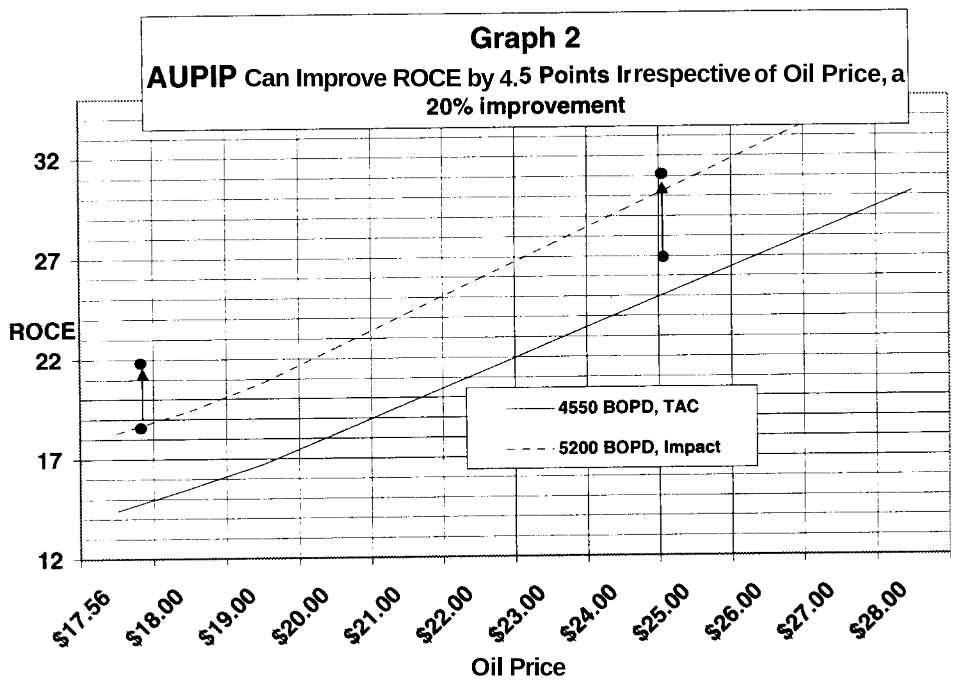


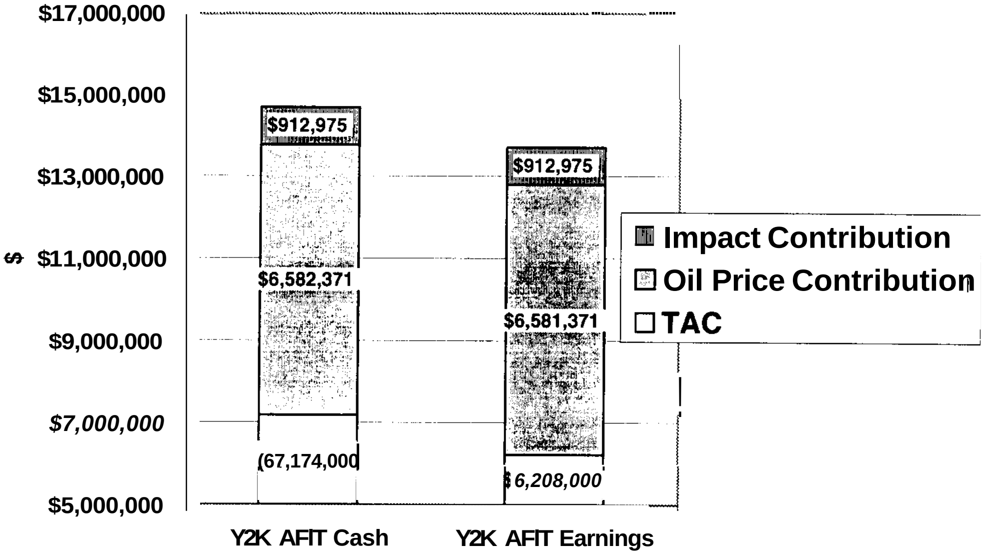
Figure 9

Graph 1
Production Impact Increases Production by 650+ BOPD





Graph 3
AU Production Impact Increases Cash and Earnings by .9MM$



Graph 4
Prodution Impact Increases Production and Decreases Lifting Costs