Production & Research-based Approaches for Maximizing Recovery in the Barnett Shale

during the Period 05/15/2001 to 05/14/2002

By

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December 2002

Work Performed Under Prime Award No. DE-FC26-00NT41025
Subcontract No. 2057-RE-DOE-1025

For
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Executive Summary

The Barnett Shale is a Mississippian age, very tight matrix, naturally fractured reservoir in the Ft. Worth Basin in north Texas. Unprecedented drilling activity has occurred in the current core productive area (primarily Denton, Wise and Tarrant co.), and Barnett activity continues as the second largest Texas gas field. Since 1981, field cumulative production is roughly 0.365 TCF, and is on pace to reach 1.5 TCF cumulative by 2006.

The U.S.G.S. estimates between 3.4 and 10.0 TCF of shale gas are recoverable[1] within the identified play area, making the Barnett an important piece of the economic puzzle for shale gas resources in the U.S. There are many Barnett successes for operators, but a focused, integrated study could help enhance the knowledge base and provide a springboard for improved overall ultimate recoveries. While a percentage of wells are better than 1 BCF, and refrac treatments do improve well reserves – overall gas resource <u>recovery-per-well</u> is lower than the industry needs, considering the activity level. Barnett challenges include:

- Higher liquid volumes & poorer fracture dehydration than desired for gas wells.
- The need for better baseline data, and understanding of core properties as it relates to Barnett Shale completion and production methods.
- Developing approaches and technologies to give Barnett fieldwide recovery an opportunity to approach to upper end of U.S.G.S. recoverable gas spectrum.

The Barnett is a very successful Play for a number of operators including Republic Energy, Inc. (Dallas, Texas). However, Republic has taken the pro-active step in joining the Department of Energy, Penn State University and the Stripper Well Consortium with the goal of maximizing Shale gas resources. The project focus is *underperforming wells, their known and suspected underlying causes, and improving fieldwide Shale ultimate recoveries*. Total project allotted budget is $98,550, with Republic Energy bearing a $25,550 total share and the balance funded by the U.S. DOE.

This is the first comprehensive Barnett Shale project which provides a model for other area operators, developing the link between: Rock characteristics, Fieldwide flowback, pressure and chlorides trends, and the Effect of conventional & high-rate dewatering on gas well performance.

The three project objectives are:

- Focus on improving gas recovery in wells that don't have benefit of well-connected natural fracture system.
- Characterizing mechanisms that control gas & water recovery in the reservoir at the *pore level* – using reservoir core.
- Testing reservoir drawdown limits and effect of maximum water removal, known as gas/water 'Co-Production' using Electric Submersible Pump (along w/ other lift methods like plunger lift and rod pump).

Results Summary & General Conclusions

Barnett rock is surprisingly not extremely water sensitive. It shares fracture and cleating characteristics with some coals, and has an apparent tertiary production mechanism (methane molecule desorption) at low reservoir pressure when properly dehydrated. In carefully controlled laboratory tests using Barnett core, two (of nine) commercial products were shown to enhance loadwater recovery and gas permeability recovery on core in the laboratory.

A sizeable percentage of Barnett wells suffer from liquid loading problems and poor fracture dehydration. Analysis of fieldwide flowing pressures, flowback / produced water trends, as well as chlorides trends show this to be the case. There is strong evidence that the source of high liquids production is bounding Viola or Ellenberger zones.

Republic's pro-active approach of using aggressive Co-Production dewatering improves wells that don't behave like a typical flowing, trouble free gas wells. Dewatering with rod pump has been shown to add an estimated incremental 330 MMCF / well, and plunger lift an estimated incremental 90 MMCF / well, on average. Twelve wells were included as test cases, and tests are currently ongoing. *Note that estimates of incremental production and EUR may change over time as further data becomes available, and estimates are also subject to judgemental factors.

High drawdown ESP's (submersible pump) were used dewater high PI wells in two 30-day test cases, to liberate trapped gas as shown successful in other gas / water basins. Even with detailed pre-planning, well tests did not adequately prove / disprove the concept of liberating trapped gas within pore spaces and lowering reservoir pressure (at least in our two candidate wellbores), and operational problems were also an issue. Gas was produced from these two non-flowing wells during the test period, but in uneconomic proportions.

In conclusion, this project was designed to serve as a model for area operators and others involved in developing unconventional Shale resources. The ultimate project goal is maximizing Barnett Shale gas recovery to the economically feasible limit, through the integration of baseline research and field production approaches.

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Reservoir Characterization and Regional Activity Level

Possibly the most active natural gas play in the lower 48 states, the Barnett Shale is a Mississippian age naturally fractured reservoir in the Ft. Worth Basin in north Texas. Drilling depths are typically between 6800 to 8600 ft., and the reservoir unit has between 200 to 700 ft. of gross interval in the current core productive area (primarily Denton, Wise and Tarrant co.). From its outcrop in central Texas (Llano uplift), the unit dips northward to a maximum thickness of near 1000 ft. near the Texas / Oklahoma state line[1,2]. The Barnett shale is both a non-siliciclastic source rock and a reservoir rock, with generalized drill cuttings composition being dense, black, with a lignite-type appearance. The clay content is measured between 20-40% by volume from available samples using SEM, with smectite and illite comprising a large proportion.

The Barnett Shale is usually described as having two productive units; The massive Lower Barnett which exhibits layered reservoir behavior, and the Upper Barnett which is about 20% of the gross thickness of the Lower. The Forestburg Lime section lies between the Upper and Lower Barnett with variable thickness. The Marble Falls Lime provides the apparent seal above, while the Viola Lime provides the lower boundary for the reservoir.

Detailed work by GRI [3-7] and others have shown that the Barnett Shale exhibits dual-porosity behavior because of its limited volume, “high” permeability natural fractured system coupled with a low permeability matrix (0.001- 0.0001 md). Natural fractures trend in a NW to SE direction, while induced hydraulic fractures run NE to SW. Since roughly 1999, almost all Barnett Shale wells are currently water-fractured with 0.8 to 1.5 million gallons of fresh (slick) water at high rates (60-80 BPM), with operators moving away from MHF’s with gel performed previously. Lowering well completion costs was the primary driver for this shift, while maintaining comparable well performance. The Barnett is considered a ‘dry gas’ reservoir in general terms, but associated water and areas of condensate production are concerns as development continues. A sizeable percentage of underperforming Barnett wells have been completed across the Play, with liquid production and reservoir quality problems. This project examines these problems, gathers quality reservoir / field data, and attempts to develop solutions for improving well performance.

Current drilling activity in the Shale is impressive, and the aerial productive limits of the play have yet to be defined. 3000 to 5000 locations could be left to drill among all operators within the play. Some quick facts on area activity:

- Between 1981 and 1990, 71 wells were drilled.
- During the period between 1990 and 11/2000, 705 wells were drilled!
- 25-30 drilling rigs currently operating
- 2000 total production was over 79 BCFE, and climbing.
- 2nd largest gas field in Texas.
- Field Cum-to-Date since 1981, roughly 0.365 TCF.
- At current pace, roughly 1.5 TCF cum gas by early 2006.
- Impressive well production has recently been coming from expansion southward, into NE Tarrant Co. and into the Ft. Worth city limits.

Tight natural gas demand and low cost completions will continue to fuel activity in the region; however, this in turn places a greater emphasis on the industry's production practices and artificial lift technology to maximize gas recovery as time moves on.

The principle company in this project is Republic Energy Inc. (REI) is a small, independent company which is currently the second-largest Barnett operator with over 120 wells. By contrast, over 900 have been drilled by Devon Energy (formerly Mitchell Energy & Development Corp.), the area's largest operator. The Barnett is a very successful Play for Republic and a number of operators. However, the main project focus is *underperforming wells, their known & suspected underlying causes, and improving fieldwide Shale gas ultimate recovery*.

Problem Description

Understanding factors that dictate initial well productivity (IP) and EUR are absolutely essential for maximizing gas resource utilization in this area. The U.S. Geological Survey estimates that between 3.4 and 10.0 TCF of shale gas are recoverable[1] within the identified play area, making the Barnett Shale an important piece of the economic puzzle for shale gas resources in the Lower 48 states. While a percentage of wells are better than 1 BCF, and refrac treatments improve well reserves – the industry and Barnett Shale operators need ways to ensure that overall resource recovery-per-well is maximized, especially considering the activity level and the resource opportunity that exists in this area.

Projected fieldwide, and even extending to a possible 5000 drilling locations across 175,000 ac**. (Figure 1),** this “lower” percentage recovery is leading to fieldwide ultimate recoveries toward the lower end of the U.S.G.S. recoverable shale gas spectrum (3.4 TCF estimate). Liquid production from a high percentage of gas wells (50-400 bbl/ MMCF of both formation & frac water) is compounding the problem of lower ultimate recoveries, and is also symptomatic of reservoir and completion problems. The above facts and trends are the justification for this proposal: To gather the proper baseline data, apply proven production engineering technology and develop new approaches to improve EUR’s to the economically feasible extent. The goal of the SWC is to maximize Shale gas resources, and attempt to develop solutions in working toward that goal.

WELL COMPLETION & RESERVOIR BACKGROUND

A typical completion approach (with many variations along the way) has been to fracture both the Upper and Lower Barnett (together or separately depending on barrier thickness) to increase chances of intersecting natural fracture systems. Since roughly late 1998, most Barnett Shale wells are water-fractured with 0.8 to 1.5 million gallons of fresh (slick) water at high rates (50-90 BPM), with low sand concentrations usually ramped up to less than 1.4 ppa at the tail-end of the treatment. This switch to waterfracs was driven by the need to lower well completion costs. Wells are completed without packers, using the annulus for production assistance.

Flowbacks are normally very aggressive, moving 200-300 or more bbl/hr until casing pressure declines & breaks back. Loadwater recovery from flowback is commonly in the 8-25% range, depending on geographic area.

Regarding reservoir quality - well performance appears to be a moderate-to-strong function of density porosity, natural fracture volume along with quartz content within the Shale. Reservoir communication both vertically (to bounding Viola lime and Ellenberger sand) and aerially, due to induced & natural fracture cross-communication, also likely affects well performance. **Figure 2** shows generic Barnett geologic zones and a typical zonal completion.

SPECIFIC PRODUCTION PROBLEMS (FIELDWIDE WELL REVIEW)*

- Since 1998, approx. 22% of wells (208 of 942) IP'd < 380 MCFD
- Since 1998, EUR's are projected < 500 MMCF for approx. *25% of all wells*.
- Since 1998, EUR's are projected < 250 MMCF for approx. *12% of all wells*.

* Note that estimates of incremental production and EUR may change over time as further data becomes available, and estimates are also subject to judgemental factors.

- A surprisingly high percentage of wells with high post-sales liquid production. 41% of Barnett wells > 80 bbl/MMCF water – both frac treatment & formation water. Data are a sample of 140 wells across the field.
  - Data Range = 2 – 2000 bbl/MMCF water and/or condensate. Median = 57 bbl/MMCF. Mean = 127 bbl/MMCF (for 140 well sample).

GENERAL FIELD PROBLEMS

- High water production, due to: Poor fracture dehydration & load recovery – leaving water on the reservoir, or water influx from water-bearing Viola & Ellenberger layers.
- Waterfracs have improved economics, but well performance & fracture cleanup / height containment sub-optimal in some areas.
- Pumping high freshwater frac volumes in a formation having mixed-layer clays.
- Reservoir capillary forces dominate in a very tight matrix, along with very low conductivity hydraulic and natural fracture systems.
- Difficult to overcome strong capillary forces in a very tight reservoir – thought to hamper wellbore cleanup and cause small calculated drainage areas.
- WHP decline to sales line pressure (#350-425) within 15-45 days. Very steep early-time hyperbolic decline.
- Concerns about near-wellbore water or condensate blocks.
- Degrees of lateral & vertical communication between pay & bounding layers.
- *The need for better data to relate rock characteristics to producing profiles, to uncouple geologic and well completion factors, and to develop predictive models to improve ultimate recoveries.*

Objectives Statement & Summary

The ultimate objective is to move a higher percentage of wells into the "good" Barnett well category (> 180 MMCF 1st year, slower WHP decline, etc.) using a research and production-based approach to develop baseline lab data, and try new production approaches (for this area). This type of fully integrated approach has not been applied in the Barnett Shale to date within one study.

In summary, the plan is to:

- Focus on improving gas recovery in wells that don't have benefit of well-connected natural fracture system.
- Accurately characterize mechanisms that control gas & water recovery in the reservoir at the *pore level* – using reservoir core.
- Test reservoir drawdown limits and effect of maximum water removal, known as gas/water 'Co-Production' using Electric Submersible Pump (along w/ other lift methods like plunger lift and rod pump).

Our focus is on gas wells with a higher than average water-producing tendency – wells drilled in 'non-core' areas or ones without the benefit of a well-connected natural fracture system. **Figure 3** shows general problem areas within the current Barnett Play, and locations were core material was obtained for testing.

This is a three-phase project that includes laboratory and field components, where gas-water 'Co-Production' is the chief method employed to maximize gas rate. The idea of moving as much water as possible is basically untested in this reservoir. Field testing 'Co-Production', along with lab testing reservoir core responses to maximum drawdown at varying water saturations & with surfactant chemicals, will determine if we can maximize well EUR's w/ this analysis.

PROJECT FUNDING LEVEL

Total estimated cost to Penn State for the performance of this subcontract was not to exceed $73,000. Republic Energy shares a $25,550 in-kind contribution in the total project cost of $98,550.

Three-Phase Work Plan

This is an ambitious, integrated study which has laboratory and field-testing components. Meeting the objectives stated above required the following three phases:

- Laboratory Pore-Level Characterization of the Shale
- Flowing Pressure Analysis of Water / Condensate Production
- Field Co-Production & Fracture Dewatering

BACKGROUND - LABORATORY PORE-LEVEL CHARACTERIZATION

Republic and Stim-Lab^{tm} (Duncan, OK) designed the proper tests to evaluate ideas about the reservoir rock and producing character, and allowed for proper scale-up of lab results to the field level.

14 sidewall core plugs were cut from one well in key Barnett shale (and bounding member) strata. This well was located in a northern, less prolific area where the Barnett can produce gas, water & condensate phases.

15 core plugs (cut from whole slabbed core) were obtained from the University of Texas Bureau of Economic Geology – from a previously cored well (a very high EUR well) in the heart of the Play from an offset operator. See Figure 3 for these locations, and their proximity to the areas of high liquid production (water & condensate)

StimLab is helping us design the proper lab test procedures for this reservoir rock. Plans for data were:

- Basic properties (porosity, klinkenberg perms, bulk grain density, etc.)
- Thin section XRD / SEM analyses
- Critical salinity tests (for Shale sensitivities to different salinity ranges & FW)
- Flowback & Regained permeability tests of Shale to fluids (various surfactant types, etc.)
- Methane desorption & determination of ‘threshold pressure’

We needed quality baseline petrographic data on the Barnett from areas with different producing tendencies. <u>We want to learn mechanisms that control frac loadwater recovery, fluid sensitivity to additives, and the gas desorption potential from this Shale (as reservoir pressure is lowered).</u>

BACKGROUND - FLOWING PRESSURE ANALYSIS OF LIQUID PRODUCTION

Low calculated fractured well drainage areas (5-15 ac.) are thought to be due to hydraulic fractures which are not properly dehydrated. Data shows that long hydraulic fracs are induced but may be stress sensitive, and its suspected that tortuosity combined with near-wellbore liquid saturations could cause excessive reservoir energy (pressure) loss. This impacts calculated drainage radii, gas well performance and ultimately EUR's.

Evaluation of well flowing pressure trends & early-time production data were used to examine why high percentages of Barnett Shale wells suffer from natural or induced liquid problems, and aggressive approaches that can improve gas rates & EUR's.

Data gathering and interpretation consists of:

- Early & late time flowing tubing & casing pressures, pressure decline trends & gas / water rates for over 140 total Barnett wells.
- Flowing pressure differentials between tubings & casings, which signify a well's liquid production & liquid loading tendency.
- Identifying geographic areas of known problems in the Barnett, and what completion / production approaches can be used to maximize gas rate & EUR.

BACKGROUND - FIELD CO-PRODUCTION & FRACTURE DEWATERING

Properly designed field tests using submersible pumps for gas-water Co-Production comprise the core of the dewatering approach in this project. In wells with high liquid producing tendencies (for Barnett, high PI's are 0.3 – 5.0 bbl/day/psi), properly sized ESP's can provide maximum and consistent bottomhole pressure drawdown by removing the hydrostatic head component in wells roughly 8000' deep.

For Republic, two (2) candidate wells for ESP testing were selected (for both practical and logistical reasons) – wells in different parts of the Barnett:

- Northern, less prolific area where the Barnett can produce gas, water & condensate phases.
- Near the main (Southern) Barnett area, but in a specific location of high liquid production and some non-flowing wells. (See Figure 3 for approximate location)

Also, less-aggressive styles of Co-Production dewatering are underway for Republic:

- Rod pump in three (3) Barnett wells
- Plunger lift in seven (7) Barnett wells.

The major differences are rod pump / plunger lift methods operate with an on-off drawdown condition in wells with a lower productivity index (PI) and bottomhole pressure, while ESP's allow for a constant (and often greater) bottomhole drawdown in gas wells with a sufficient liquid PI. Results from all styles of Barnett Co-Production have been integrated and the benefits quantified.

Bulleted Summary of Overall Project Results

LABORATORY CHARACTERIZATION PHASE

- All shale zone samples showed < 0.01 md permeability. This adds to the prevailing opinion that matrix is not the primary production source, and only acts as desorption storage similar to coalbed.
- Based on the salinities tested (freshwater to 150,000 ppm), the Barnett is *not* extremely water sensitive. The one case where FW sensitivity was shown (Barnett 'C' zone, Northern well), as little as 5000 ppm controlled this sensitivity.
- Nine commercial additives were tested for improved water recovery and increased gas permeability.
  - Plexsurf WRS-C (Chemplex Inc.) improved k_{GAS} over 24%, but at 4 times the recommended concentration (2 gal/1000 gal).
  - ProSurf I Plus (1 gal/1000 gal) & Prosurf II (0.5 gal/1000 gal) measurably lowered time to recovery, and improved k_{GAS} over 5% (American Energy Services, Inc.).
  - Inflo 45S (2 gal/1000 gal) & Prosurf II (2 gal/1000 gal) improved k_{GAS} over 9% (BJ Services, Inc.).
  - Cudd RFF-1 (1 gal/1000 gal) improved k_{GAS} over 10% (Cudd Inc.).
  - The other four products either foamed and hampered flow or showed no substantial improvement for their cost.

FLOWING PRESSURE ANALYSIS OF PRODUCED LIQUIDS PHASE

- High liquids production that causes problems in Barnett wells is almost certainly not Barnett water, but fluid from sub-bounding Viola & Ellenberger zones. This is verified by flowback analyses, chlorides trends vs. time, and flowing pressures.
- Long hydraulic fractures are induced upon treatment (killing offset wells). However, low calculated drainage areas are due to stress-sensitive fractures and

liquids in the fracture (in the underperforming groups), causing high energy losses in the reservoir.

- Poor fracture dehydration occurs due to high volumes of frac water- *especially combined with high influx volumes from Viola & Ellenberger zones.*
- Northward in the Barnett, three-phase production (cond./gas/water) further compounds problems for flowing gas wells. PVT analysis verifies that free liquid exists *in the reservoir* (#6800 gas dewpoint, #3600 BHP), along with fluid from sub-bounding Viola & Ellenberger zones.
- Figure 3 shows areas of high liquids production (flowback & sales-line water).
- Early-time chlorides trends show a strong relationship with production & EUR – the higher the slope and higher the value, the poorer the well. **Figures 4, 4 (#1-5), and Figure 5** detail this trend.
- **Figures 6 & 7** show EUR is strongly inversely related to Frac Loadwater Recovery (bbl) and to Total Load Recovery (flowback + production water, bbl).
    - o < 1BCF wells make > 10,000 bbl Frac Loadwater and > 20,000 bbl Total Load.
    - o No well > 1 BCF makes over 8,000 bbl Frac Loadwater or over 18,000 bbl Total Load.
    - o A considerable number of wells lie somewhere in between this spectrum, mainly due to early-time data & sample size (n = 60).
- **Figure 8**, Gas Rate versus GLR (scf/bbl liquid) shows a bi-modal distribution and two different types of Barnett wells, when examined across the field as a whole.
- **Figure 9** shows a strong correlation between Time to WHP blowdown (days) plotted versus Ultimate recovery (EUR, MMCF).
- A sizeable percentage of Barnett gas wells need artificial lift (at various times in the well life cycle) to either prolong a flowing condition, or to overcome hydraulic forces that impede gas flow & wellbore unloading. Common options are:
    - o Swabbing, Flow intermitter, capillary or velocity strings, plunger lift, compression, rod pump, gas-lift & ESP.

FIELD CO-PRODUCTION & FRACTURE DEWATERING PHASE

- High-rate gas / water Co-Production (80-500 BWPD) was previously untested in this reservoir, and only recently become a viable option, to due more drilled acreage encountering marginal reservoir quality.
- Aggressive Co-Production in gas wells (using below-perforation ESP's w/ variable-speed drives) was the featured approach of this project, drawing on experience and success from south Texas and New Mexico Permian Basin in fractured reservoirs.
- ESP designs were finalized after data were gathered from the first two project phases (Lab Core & Flowing Pressure Analyses).

- Two candidate wells for ESP testing were chosen in:
  - Northern, less prolific area where the Barnett can produce three phases.
  - Near the main (Southern) Barnett area, but in a specific location of high liquid production and some non-flowing wells.
- Other Co-Production methods utilized by Republic are:
  - Rod pump in three (3) Barnett wells
  - Plunger lift in seven (7) Barnett wells.

RESULTS

- Even with all the pre-planning, there was operational difficulty getting good ESP tests in the 30-day period, with allotted funding. High volumes of liquid were removed to recover gas from non-flowing wells, but in uneconomic proportions.
  - Northern well cum. test production: 1400 MCF, 7259 BW
  - Southern well cum. test production: 260 MCF, 3240 BW
- Northern well encountered a csg. problem and was set above-perfs, had problems with gas-locking, and downhole cycling of fluid in recirculation pump system.
- Southern well test was cut short by producing large sand volumes, even with a gradually increased drawdown using a variable-speed drive.
- The more extreme approach of <u>downhole sand-control combined with "super sand pump" ESP's</u> would be required for permanent installations with high drawdowns. Economics of sand-control + variable-speed controlled ESP are marginal at < $3.00 / mcf gas price.

- Overall, pro-active conventional dewatering has been a success for Republic Energy in the Barnett Shale:
    - Since early 2001, 12 gas wells have required aggressive lifting.
    - Gas well dewatering has produced approx. 209.3 MMCF, 500 BC and 46,713 BW since early 2001 (12 wells).
    - Approx. undiscounted gross revenues from this approach ($3.00 gas, 82% NRI, $1 bbl disposal) are $477,000.
    - Capital investment has been approx. $202,000 total from (2) ESP tests, 3 rod pumps and 7 plunger lift systems.
    - Incremental EUR's are over 330 MMCF / well for the rod pumped wells (3), and approx. 90 MMCF for the plunger lifted wells (7) on average.

Discussion of Results

LABORATORY CHARACTERIZATION PHASE

The purpose of this phase was to conduct petrographic examination, fluid sensitivity studies and additive evaluation for enhanced flowback on the Barnett Shale. The samples spanned the Upper Barnett, Forestburg, five members of the Lower Barnett (A, B, C, D and E) and the Viola beneath the Lower Barnett **(Table 1 and Figure 2)**. X-ray diffraction (XRD), thin section (TS) analysis were performed on the various core plug samples to classify the samples and group them for further testing. Figure 3 shows the approximate locations of the Northern and Southern wells within the field, where core material was obtained for testing.

Further testing (with the same core) included fluid sensitivity by the capillary suction time (CST) testing method and flow studies with ground Barnett formation material to evaluate various additives from different suppliers on their ability to enhance and speed recovery of gas production following hydraulic fracture stimulation with water. Laboratory procedures for Capillary Suction Tests and the Flowback Additive Studies are described in detail in **Appendix 1**.

Table 2 shows different brines formulations used for testing, based on typical produced water used in water fracs in the Barnett. These fluids spanned the range of conditions encountered, from freshwater to an extreme of 150,000 ppm brine (which in some cases, this high salinity flowback water from other wells is used for fracing).

Table 3 gives the results of the routine air permeability and Helium porosity measurements. All shale zone samples showed less than 0.01 md permeability. This suggests that matrix permeability is not the primary source production and only acts as desorption storage similar to coal. Based on these results it was decided to conduct fluid sensitivity and flow studies using ground shale samples.

Table 4 gives the results of the capillary suction time (CST) tests. Fluids evaluated represented several potential cases for fluid exposure based on available and potential fracturing fluid sources. The samples for CST tests were grouped as given in Table 1. Typical values for CST ratio vary from 0.5 for no sensitivity to >45 for extreme sensitivity. However, the values must be compared to a control (usually freshwater) for evaluating results for any sample. Most of the samples evaluated showed little fluid sensitivity to brief (<1 hour exposure) to the various fluids tested. Only one sample from the Lower Barnett C zone in the Northern well showed any fluid sensitivity and this was only to freshwater. Addition of as little as 5,000 ppm salinity controlled this sensitivity.

Table 5 shows the flow study results. Initial testing results showed it was most valid to rely on Time to gas recovery and Amount of water remaining in the pack compared to a control for evaluating the various products. Time to recovery is compared. This is the time at the point where the relative permeability first stabilizes. Equivalent time to recovery gives the time to the point where the gas permeability following treatment reached the same relative permeability value as the pretreatment gas flow. A shorter value for equivalent recovery time would indicate enhanced load water recovery. A higher relative permeability may also result due to the lower water saturation (Sw). A time for equivalent recovery is not given if the post treatment gas flow failed to reach the pretreatment gas permeability.

Nine (9) products were evaluated in the initial screening tests with the composite Lower Barnett samples from the Southern well. Water recovery was good for all products compared to the controls. However, the controls were conducted with composite samples from the Lower Barnett Northern well core plugs. Therefore, for the Southern well screening tests it would be best to compare relative results for the different products and reserve control comparison to the Northern well tests.

Plexsurf WRS-C from Chemplex was evaluated at two concentrations to determine if increasing the concentration improved effectiveness. Since the treatments were performed on the same pack, only one retained water mass was measured at the end. At the 0.5 gal/1000 gal concentration, the treatment proved ineffective at improving the relative gas permeability. Increasing the concentration to 2 gal/1000 gal increased relative permeability, but it did not shorten the time to recovery. This may be due to a slight increase in viscosity of the solution (not measured) with the higher additive concentration lengthening the fluid displacement time with gas. Unfortunately, budgeting did not allow for evaluation of all candidates at several concentrations.

Two products created foam upon gas return flow. These were SSO-21 and CatFoam. The foam trapped gas within the core resulting in reduced retained relative gas permeability. Two products were selected from the initial screening for further study with the Northern Well Lower Barnett samples. These products were American Energy Services Prosurf I and II combination and BJ Services Inflo 45S which both improved the relative gas permeability and had low retained water saturation within the pack. *The Plexsurf WRS-C was not chosen to continue as it only performed at four times its recommended concentration.*

Evaluation of the two products in the two groups of composite samples from the Northern Well showed less water recovery than the Southern Well samples - indicating that the character of the formation and/or age of the samples affected the water retention properties. Compared to the control samples both additives lowered the retained water compared to the control. The AES Plexsurf product was slightly less effective than the BJ 45S product in improving the relative permeability. Neither dominated in decreasing time to equivalent recovery with BJ product favored in the A,B sub zones and the AES product in the C,D,E sub zones.

Conclusions from tests performed indicate that the Barnett shale most likely produces from a fracture network as matrix permeability is extremely low. The Barnett shale is not extremely water sensitive and that the current practice of fracturing with available water with low salinity most likely creates little flow impairment. Additives to improve water recovery and therefore lower water saturations with net improvement in relative gas permeability may be beneficial and should be further explored in larger scale laboratory tests and/or field scale evaluations where conditions can be controlled to provide reasonable comparisons.

FLOWING PRESSURE ANALYSIS OF PRODUCED LIQUIDS PHASE

As described in detail previously, over 41% of sampled Barnett wells make over 80 bbl/MMCF water after being on production, whereupon adequate fracture dehydration does not occur with the available reservoir energy. It is quite clear that liquids in the reservoir and wellbore suppress Shale gas ultimate recoveries, and liquids are one of the primary factors (both in the form of large volume waterfracs and formation water influx)) leading to the current percentages of underperforming wells (see Specific Production Problems list, Page 4).

The actual origin of liquids, and their impact in relation to important factors (like geologic structure, stratigraphy and tectonics), is a matter of much debate and speculation amongst experienced the Barnett Shale operators. The data developed within this study are arguably the most complete, most robust and best integrated, to begin to define and analyze: Field liquids / production problems, Provide spatial patterns for problems, and Incorporate operational and production solutions to solve these problems and improve well production and EUR's. Key parameters worthy of analysis and understanding are:

- Field Chlorides trends by well, and groupwise versus gas production
- Fractured well flowback and total liquid recovery versus production
- Correlation between WHP blowdown time versus gas production

Chlorides

Spatially across the field, patterns in chlorides values versus time are very reliable correlating variable with well performance and gas ultimate recovery. Data from Figure 4 shows robust data sets from all across the currently active Barnett area. Data from Figures 4 (1) – 4 (5) detail the spatial pattern of chlorides trend both by areas (labeled #1-5 on Figure 4) and chlorides trends versus EUR (Figure 5).

Referring to Figure 4 for placement of trend areas:

- Figure 4 (1) – A depletion-style dry gas area with a low chlorides trend over time. These are high EUR wells and strong performers.

- Figure 4 (2) – A depletion-style dry gas area having some variability in liquids, but a relatively flat chlorides trend over time. These are high EUR wells and strong performers.
- Figure 4 (3) – A high liquids, gas/water/condensate producing area and an area with quite different reservoir characteristics. These are low-to-marginal EUR wells, and showed a much higher chlorides slope over time.
- Figure 4 (4) – A wide group of wells on the edge of a known high liquids, variable production area of the Barnett. These are low-to-marginal EUR wells, showing aggressive chlorides trends, especially when compared to Locations 1 & 2.
- Figure 4 (5) – This is a group of high chlorides, high slope trending wells in an area of known liquids production. These are low EUR wells, mixed with some non-flowing wells. Interestingly, most wells in this area had an IP > 1100 MCFD, but rapidly declined.

- Chlorides sampling program specifics: All wellhead samples, pulled in 25-ml bottles, all analyzed by the same laboratory. Sampling Program Frequency:
    - Frac fluid itself (either from frac pit or working tanks during the job)
    - Every 8 hours during flowback
    - 1^{st} five days down sales line (5 samples)
    - Normally at 30, 60, 90 day etc. intervals

This type of program allowed for some repeatability and a respectably large data set from over 80 Barnett Shale wells (sometimes 20 data pts. for a given well). The figures above don't include all wells, but the group with the most complete data sets.

- Figure 5 shows the strong correlation between maximum chlorides value reached (max. minus a 5000 ppm frac fluid baseline value) and EUR. As a rule in this data set, wells projected over 1 BCF will have chlorides < 50,000 ppm. It is our opinion that wells having > 50,000-70,000 ppm chlorides (especially early in the well life) are communicating with lower bounding zones, by porosity bands, faulting, fractures or karsted Viola and Ellenberger zones.

Liquid Recovery Versus Production

EUR is strongly inversely related to Frac Loadwater Recovery (bbl) and to Total Load Recovery (flowback + production water, bbl) – FOR SOME WELLS. In a "normal" reservoir, high load recovery after fracture is a good sign. Often, a 65% load recovery is thought of as optimal. However, in a dual-porosity, fractured system – fracture load recovery analysis often sends mixed signals to operators.

- Figures 6 & 7 look at Frac Loadwater and Total Load (Frac Load + Cumulative Water), respectively.
  - They show < 1BCF wells make > 10,000 bbl Frac Loadwater and > 20,000 bbl Total Load.
  - No well > 1 BCF makes over 8,000 bbl Frac Loadwater or over 18,000 bbl Total Load.
  - A considerable number of wells lie somewhere in between this spectrum, mainly due to early-time data & sample size (n = 60).

- Figure 8, Gas Rate versus GLR (scf/bbl liquid), shows a bi-modal distribution and two types of Barnett wells, when examined across the field as a whole. Given all the reservoir variability, two or three general trends are not surprising.

WHP Blowdown Over Time Versus Ultimate Recovery

Possibly the most dramatic and telling correlation developed in this project is Figure 9, Correlation between Days to Blowdown vs. EUR (MMCF). While line pressures vary, they don't vary too far (#320-450) to make a basic correlation. Line pressures were normalized, and project ultimate recoveries were plotted.

- This graph, especially when considered with all available liquids & chlorides data, shows that Barnett production is a function of the following:
  - Porosity and permeability
  - Zonal communication
  - Fracture conductivity (& pressure-dependent conductivity)
  - Liquids in the reservoir and inside the wellbore

Underperforming Barnett wells normally blowdown to line pressure in less than 30 days, and need assistance with liquid removal pro-actively to attain an economic well EUR.

FIELD CO-PRODUCTION & FRACTURE DEWATERING

For wells already drilled within the Barnett Shale, as well as for future wells in many areas – proactive and aggressive gas / water Co-Production is the best option for moving underperforming wells into the “acceptable” part of the EUR continuum. This is especially true in a firm gas price environment (> $3.00 / mcf), where prices allow operators to take production approaches that were uneconomic at lesser gas prices.

One main project objective was to feature high rate Co-Production dewatering using electric submersible pump (ESP) below perforations. The basic premise of moving maximum water to unload wellbore, to liberate trapped gas and lower reservoir pressure to allow desorbed gas production, was basically untested in this reservoir until now. Aggressive Co-Production (using plungers and rod pumps) has been successful for Republic Energy, but dewatering with ESP (30-day tests) was not an economic success. **Figures 10 and 11** show the general schematic of plans. After first successfully proving Barnett Shale dewatering benefits, it was planned to enhance economics and water-handling feasibility by moving water (regardless of water source) back into a lower bounding zone while Co-Producing gas. This has been proven successful in some oil and gas provinces.

After evaluating candidate wells and gathering data from the other project phases for months, the following ESP approach was set into motion using Baker-Hughes Centrilift’s system. A recirculation system was chosen instead of a shrouded ESP, for purposes of motor cooling and ability to fit inside 5.5”, #17 N-80 production casing (a standard for Barnett completions since 1999, up from 4.5” prior). At near 8000’, with concerns about solids / sand / fluids, this was recognized as a challenging environment for all personnel involved. The recirculation system is shown in **Figure 12**.

- Designed to: Maximize drawdown & minimize gas interference, improve motor cooling and provide an alternative to ‘slim-line’ equipment.

Results & Timeline (ESP)

Two candidate wells were: Northern well (same well rotary sidewall cores were cut for analysis), & Well near main (Southern) Barnett area, but in a specific location of high liquid production and some non-flowing wells.

- February-May 2001- Identify problem geographical areas and high liquid PI areas. Decide on two candidate wellbores.
- August-November 2001- Design below-perfs ESP's with Centrilift™ to dewater gas wells, drawing on experience from other gas well dewatering basins.
- November 2001-February 2002 - Wait for proper timing for core acquisition, and proper timing for installation & operation.
- March-April 2002 – Prepare locations & piping for installation. Perform wellwork and begin 30-day ESP dewatering tests.
- April-May 2002 – Pull ESP, and evaluate operational & production data.

Even with all the pre-planning, we still encountered operational difficulty in getting good ESP tests during the 30-day period, and with the funding allotted. We made gas from non-flowing Barnett gas wells, and moved a high amount of liquid to recover the gas, but in uneconomic proportions.

NORTHERN WELL –
Pre-test condition: Dead (loaded, non-flowing new drill well)
Initial 'co-production' test rates: 120-160 MCFD, 300-400 BWPD
Estimated Design PI (bbl/day/psi drawdown) = 0.3
Actual PI (bbl/day/psi drawdown) = 0.5 – 0.2
Cumulative test production: 1400 MCFD, 7259 BW
Operational problems: Stuck unit above most of Barnett perfs due to casing abnormality. Decision was made to set unit at top part of Barnett zone, just above abnormality. Setting above perfs was not preferential, in a gassy environment. Had problems with gas-locking, and downhole cycling of fluid in recirculation pump system.

SOUTHERN WELL –
Pre-test condition: Dead (loaded, non-flowing for 12 months, Year 2000 well)
Initial 'co-production' test rates: 80 MCFD, 450 BWPD
Estimated Design PI (bbl/day/psi drawdown) = 0.2
Actual PI (bbl/day/psi drawdown) = 4.0 – 5.0 ! (very high for a Barnett well)
Cumulative test production: 260 MCFD, 3240 BW
Operational problems: Set unit below perfs. ESP would not move consistent fluid, even with over 7000' of fluid in wellbore and a very high initial PI. ESP appeared to move

solids, may have had casing failure. Well test cut short by producing large sand volumes, even with a gradually increased drawdown using a variable-speed drive. ESP teardown showed solids damage, even using Centrilift's best "super sand pump".

With good / complete well tests, the reservoir probably would have responded favorably – given the well PI's and the gas well history from the Southern well (prior cum 143 MMCF, IP 1200 MCFD).

Results (Plunger lift and Rod Pump Methods)

- Overall, pro-active Co-Production dewatering has been a success for Republic Energy in the Barnett Shale:
    - Since early 2001, 12 gas wells have required aggressive lifting.
    - Gas well dewatering has produced approx. 209.3 MMCF, 500 BC and 46,713 BW since early 2001 (12 wells).
    - Approx. undiscounted gross revenues from this approach ($3.00 gas, 82% NRI, $1 bbl disposal) are $477,000.
    - Capital investment has been approx. $202,000 total from (2) ESP tests, 3 rod pumps and 7 plunger lift systems.
    - Incremental EUR's are over 330 MMCF / well for the rod pumped wells (3), and approx. 90 MMCF for the plunger lifted wells (7) on average*.

(*Note incremental production and EUR estimates are subject to judgemental factors).

While these methods also have operational challenges (especially with solids & corrosive fluids on rod wells), aggressive conventional dewatering is successful at improving well revenue and EUR. This is especially true taking non-flowing (loaded and dead) Barnett wells and improving EUR's in the 200-450 MMCF* range with rod pumps.

Conclusions & Recommendations

This is the first comprehensive Barnett Shale project which provides a model for other area operators, developing the link between: Rock characteristics, Fieldwide flowback, flowing pressure and chlorides trends, and the effect of conventional & high-rate dewatering on well performance. Republic Energy has had good success with their dewatering program in terms of improving production and EUR, but economics of high-rate dewatering are best supported by a + $3.00/mcf gas price environment, due to associated costs of liquid handling and downhole challenges (especially rod and ESP). The project had three objectives:

- Focus on improving gas recovery in wells that don't have benefit of well-connected natural fracture system.
- Characterizing mechanisms that control gas & water recovery in the reservoir at the *pore level* – using reservoir core.
- Testing reservoir drawdown limits and effect of maximum water removal, known as gas/water 'Co-Production' using Electric Submersible Pump (along w/ other lift methods like plunger lift and rod pump).

These objectives were achieved using three separate phases: Laboratory, Flowing Pressure Analysis, and Field Operations Design and Testing.

Barnett rock has an extremely tight matrix, often naturally fractured, and is not (surprisingly) extremely water sensitive. It shares fracture and cleating characteristics with some coals, and has an apparent tertiary production mechanism (methane molecule desorption) at low reservoir pressure when properly dehydrated. Two commercial products were shown to enhance loadwater recovery and gas permeability recovery on core in the laboratory.

A sizeable percentage of Barnett wells suffer from liquid loading problems and poor fracture dehydration. Analysis of fieldwide flowing pressures, flowback and produced water trends, as well as chlorides trends show this to be the case. There is strong evidence that the source of high liquids production is bounding Viola or Ellenberger zones.

Aggressive and pro-active Co-Production dewatering improves wells that don't behave like a typical flowing, troublefree gas wells. Dewatering with rod pump has been shown to improve EUR's roughly 330 MMCF / well, and plunger lift 90 MMCF / well, on average (for the 12 wells tested in this project)*.

High ESP-style drawdowns are required to properly remove water from high PI wells, to liberate trapped gas as shown successful in other gas/water basins. Even with detailed pre-planning, we encountered operational ESP problems and well tests were not adequate to prove / disprove the concept of liberating trapped gas within pore spaces and lowering reservoir pressure (at least in our two candidate wellbores). Gas was recovered with this method, but in uneconomic proportions.

Recommendations

- Fracturing wells with clean freshwater appears non-damaging, but further evaluation of alternatives high-volume (+1 MM gal.) waterfracs in marginal rock quality areas is recommended.
- Field tests should be conducted with the two best-performing commercial loadwater recovery additives, to enhance early-time fracture dehydration.
- In areas of marginal rock quality to be drilled or areas where far-field communication (vertical & lateral) is suspected, operator should prepare to move high water volumes very early in the life of the gas well to maximize EUR and performance of the asset.
- The choice of dewatering method is best suited to a case-by-case basis, regarding which artificial lift method performs best to maximize gas.
- Regarding ESP, the extreme approach of downhole sand-control combined with "super sand pump" ESP is probably required for permanent installations with high drawdowns. Economics of sand-control + variable-speed controlled ESP are marginal at < $3.00 / mcf gas price.

Acknowledgments

Thanks to all personnel at Republic Energy, Inc. (Dallas, Texas) for allowing me the opportunity to developed a project that will benefit not only Republic, but hopefully other Shale Gas operators who are constantly trying to maximize production from unconventional reservoirs. Thanks also to David Burnett (GPRI), Texas A&M, Dan Crow and Jeff Knight of Centrilift, Mike Conway and Ron Himes of StimLab (Duncan, Ok.). Thanks to Craig Barbour, Mike Murphy, Jim Sizemore and Julie Connor of Champion Chemical (Healdton, OK.) for their expertise, as well as countless samples and data points run in their lab and in the field. Thanks to the Texas Bureau of Economic Geology for allowing access to Barnett core.

Thanks for the gracious support and funding from Joel Morrision of Penn State University, the U.S. Dept. of Energy, and the entire Stripper Well Consortium for supporting this integrated and ambitious project. Jason Lacewell, 817-946-7753, Lacewell@1scom.net

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Table 1
Sample List, Test Assignments and Groupings

Southern well — **3" plugs cut vertically into slabbed core**
(Can't visually distinuish A-E zones on Lower)
Well near Denton / Tarrant Co. border

Depths (top)	Depths (bottom)	Barnett Zone	Thin Sec Prep	Thin Sec Analysis	XRD	CST	Good Plugs	Additive Study
7107	7107	Upper	X	X	X	X		
7119	7119	Forestburg	X					
7124.1	7124.3	Forestburg						
7124.7	7124.9	Forestburg	X					
7128	7128	Forestburg	X	X	X	X		
7135	7135	Forestburg	X					
7141	7141	Forestburg	X	X				
7147	7147	Forestburg	X					
7154	7154	Lower	X					
7161	7161	Lower	X					
7168	7168	Lower						
7177	7177	Lower	X	X	X	X		7 Screening Tests Performed with Combined Samples
7184	7184	Lower	X	X				
7188	7189	Lower	X	X				
7197	7197	Lower	X	X				
7201	7201	Lower	X	X				
7210	7210	Lower	X	X				
7218	7218	Lower	X	X				
7222	7223	Lower	X	X	X	X		

Northern Well — **3" plugs cut as rotary sidewall plugs**

Well approx. 18 mi. north of Southern Well

Depths (top)	Barnett Zone	Descript.	Thin Sec Prep	Thin Sec Analysis	XRD	CST	Good Plugs	Additive Study
7349.5	Upper		X	X				
7370	Upper		X	X	X	X[a]	X	
7374.5	Upper	dense	X	X			X	
7710	Lower A	did not recover						
7720	Lower A	hot GR in A	X	X	X	X		
7860	Lower B	mid B	X	X	X	X		Two Tests
7900	Lower C	mid C	X	X	X	X		
7937	Lower D	normal D zone, no fault	X	X		X[b]		
7947	Lower D	main fault D zone	X	X	X		X	
8005	Lower E	mineral filled fractures	X	X			X	Two Tests
8023	Lower E	small fault & central E	X	X	X		X	
8055	Lower E	another E lobe	X	X			X	
8071	Lower E	open E fractures	X	X	X	X		
8085	Viola	karsted Viola (very top)	X	X	X-N/C			
8184	Viola	karst breccia	X	X	X	X		

a - combine samples to have enough material

b - 7937 similar to 7947, CST on one and XRD on other for enough material

Stim-Lab

Table 2

Brine Formulations Used in CST And Flow Studies

Component	5,000 ppm	5,000 ppm + 1% KCl	50,000 ppm	150,000 ppm
	Concentration (g/L)			
NaCl	6.19	6.19	61.9	184.8
$CaCl_2 - 2H_2O$	1.85	1.85	18.5	55.5
$MgCl_2 - 6H_2O$	0.77	0.77	7.7	23.1
KCl	0	10	0	0

Table 3

Routine Air Permeability And He Porosity Analysis of Northern Well Rotary Sidewall Samples

Sample I.D.	Depth feet	Helium Porosity %	Permeability (800psi) Air md	Permeability (800psi) Klinkenberg md	Grain Density g/cm	Lithology
14	7370.0	*	<0.001	<0.001	*	Upper
13	7374.5	*	<0.001	<0.001	*	Upper
9	7900.0	*	0.005	0.002	2.46	Lower C
7	7947.0	*	<0.001	<0.001	*	Lower D
6	8005.0	*	<0.001	<0.001	*	Lower E - fractures?
5	8023.0	3.4	0.010	0.004	2.50	Lower E
4	8055.0	*	<0.001	<0.001	*	Lower E
2	8085.0	4.7	0.103	0.081	3.03	Viola Fm. - Pyrite Clast

* unable to measure

Table 4

Capillary Suction Time (CST) Results

Southern Well

Depth (ft)	Interval	Fluid	Blank Time (no sample)	Sample (sec)	CST Ratio
7107	Upper	150,000 ppm Brine	9.30	37.4	3.0
		50,000 ppm Brine	8.40	26.2	2.1
		5000 ppm + 1%KCl	8.20	26.7	2.3
		5000 ppm Brine	8.20	27.9	2.4
		Freshwater	8.10	29.6	2.7
7128	Forestburg	150,000 ppm Brine	12.20	39.2	2.2
		50,000 ppm Brine	10.60	31.5	2.0
		5000 ppm + 1%KCl	10.50	28.1	1.7
		5000 ppm Brine	10.50	28.1	1.7
		Freshwater	10.20	32.8	2.2
7177	Lower	150,000 ppm Brine	12.20	24.2	1.0
		50,000 ppm Brine	10.60	29.0	1.7
		5000 ppm + 1%KCl	10.50	26.1	1.5
		5000 ppm Brine	10.50	16.0	0.5
		Freshwater	10.20	29.8	1.9
7222/7223	Lower	150,000 ppm Brine	12.20	39.2	2.2
		50,000 ppm Brine	10.60	28.2	1.7
		5000 ppm + 1%KCl	10.50	19.6	0.9
		5000 ppm Brine	10.50	24.0	1.3
		Freshwater	10.20	25.1	1.5

Northern Well

Sample #		Fluid	Blank Time (no sample)	Sample (sec)	CST Ratio
7349.5/7370	Upper	150,000 ppm Brine	11.90	56.1	3.7
		50,000 ppm Brine	10.70	48.3	3.5
		5000 ppm + 1%KCl	9.70	39.3	3.1
		5000 ppm Brine	9.70	51.1	4.3
		Freshwater	9.60	54.5	4.7
7720	Lower A	150,000 ppm Brine	11.90	48.7	3.1
		50,000 ppm Brine	10.70	49.6	3.6
		5000 ppm + 1%KCl	9.70	41.8	3.3
		5000 ppm Brine	9.70	38.1	2.9
		Freshwater	9.60	39.2	3.1
7860	Lower B	150,000 ppm Brine	11.90	23.5	1.0
		50,000 ppm Brine	10.70	21.5	1.0
		5000 ppm + 1%KCl	9.70	23.8	1.5
		5000 ppm Brine	9.70	19.9	1.1
		Freshwater	9.60	18.3	0.9
7900	Lower C	150,000 ppm Brine	11.90	57.3	3.8
		50,000 ppm Brine	10.70	55.3	4.2
		5000 ppm + 1%KCl	9.70	48.9	4.0
		5000 ppm Brine	9.70	43.2	3.5
		Freshwater	9.60	85.2	7.9
7937	Lower D	150,000 ppm Brine	11.90	29.5	1.5
		50,000 ppm Brine	10.70	22.1	1.1
		5000 ppm + 1%KCl	9.70	21.2	1.2
		5000 ppm Brine	9.70	20.0	1.1
		Freshwater	9.60	28.4	2.0
8071	Lower E	150,000 ppm Brine	9.30	29.2	2.1
		50,000 ppm Brine	8.40	24.2	1.9
		5000 ppm + 1%KCl	8.20	19.3	1.4
		5000 ppm Brine	8.20	22.8	1.8
		Freshwater	8.10	24.1	2.0
8184	Viola	150,000 ppm Brine	11.90	24.1	1.0
		50,000 ppm Brine	10.70	17.9	0.7
		5000 ppm + 1%KCl	9.70	14.9	0.5

TABLE 5 - Chemicals To Aid Dewatering of Barnett Shale Following Fracture Stimulation

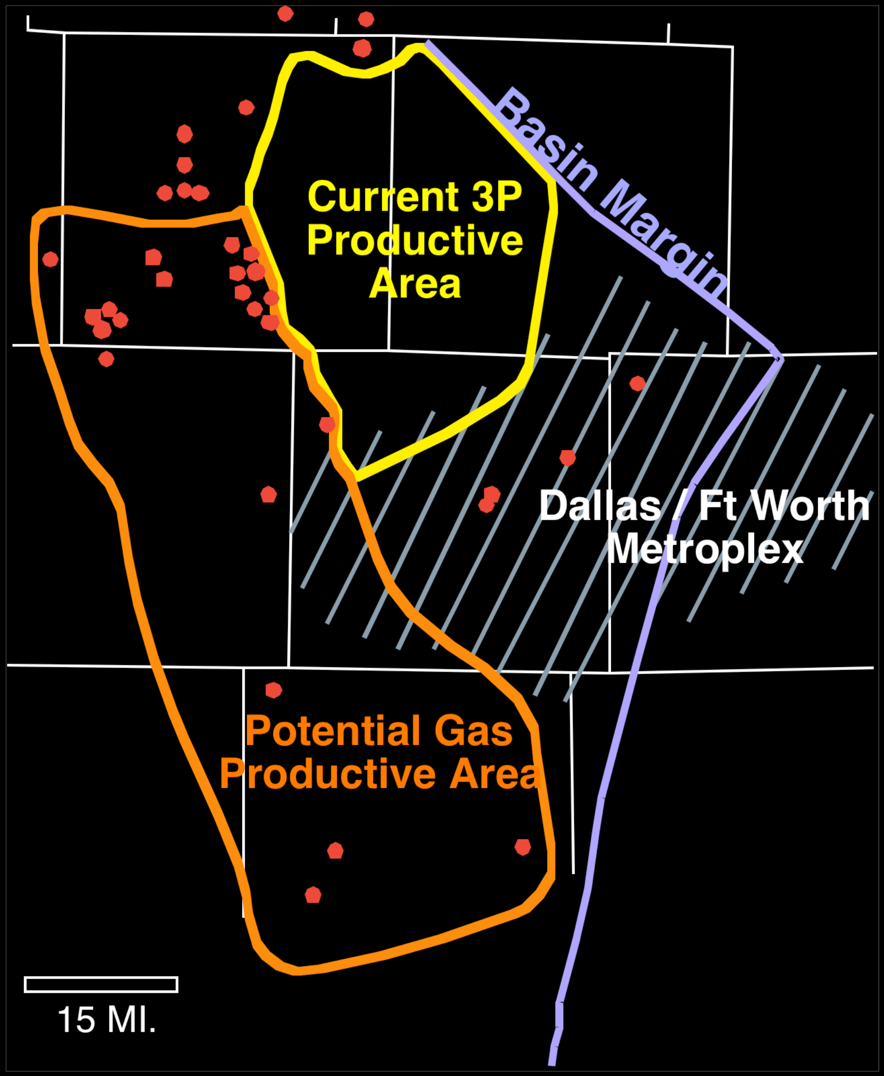
Sample	Treatment in 50000ppm Cl brine	Supplier	Pack Weight Wet (g)	Dried Pack Weight (g)	Pack Water Remaining (g)	Sw Estimate From Control (%)	Time to Max. Recovery (min)	Time to Equivalent (min)	Gas Data				Comment
									Time to Max. Recovery (min)	Kg before (md)	Kg After (md)	Increase in Kg (%)	
Southern Well' Lower Barnett	.5gal/1000gal Plexsurf WRS-C	Chemplex, Snyder, TX					28.2	N/A*	24.2	4691	4514	-3.77	
	2gal/1000gal Plexsurf WRS-C	**Chemplex, Snyder, TX**	**34.921**	**34.731**	**0.190**	**2.2**	**24.2**	**24.0**	**47.3**	**4514**	**5637**	**24.88**	
	1gal/1000gal CESI Chemical LB-1327	CESI, Duncan, OK	35.318	34.894	0.425	5.0	31.2	28.0	29.2	3906	3981	1.92	
	1gal/1000gal CESI Chemical LB-1325	CESI, Duncan, OK	35.168	34.876	0.292	3.4	12.1	12.0	12.0	6938	6994	0.81	30-100 mesh
	1gal/1000gal Prosurf I plus 0.5gal/1000gal Prosurf II	**American Energy Services**	**35.189**	**34.917**	**0.273**	**3.2**	**21.0**	**17.5**	**23.0**	**4496**	**4698**	**4.49**	
	2gal/1000gal Inflo 45S	**BJ Services**	**31.939**	**31.763**	**0.177**	**2.1**	**29.2**	**40.0**	**46.3**	**6377**	**7009**	**9.91**	
	2gal/1000gal Inflo 102 Experimiental	BJ Services	35.298	34.728	0.570	6.7	49.4	N/A	44.3	8283	8160	-1.48	
	1gal/1000gal Cat-Foam**	Clearwater, Inc., Pittsburgh, PA	33.175	33.010	0.165	1.9	31.3	N/A	37.2	6922	5509	-20.41	Foamed
	2gal/1000gal SSO-21M	Halliburton Energy Services	36.503	34.750	1.753	20.6	32.3	N/A	27.2	6092	782.9	-87.15	Foamed
Northern Well' Lower A,B	2gal/1000gal Inflo 45S Aborted and Repeated	BJ Services	35.893	34.754	1.139	13.4	27.0	21.0	27.0	5740	6069	5.73	
	1gal/1000gal Prosurf I plus 0.5gal/1000gal Prosurf II	American Energy Services	35.593	34.040	1.554	18.3	20.2	N/A	15.1	7413	7316	-1.31	
Northern Well' Lower C,D,E	2gal/1000gal Inflo 45S	BJ Services	35.688	34.894	0.794	9.3	10.1	12.0	14.1	5933	6288	5.98	
	1gal/1000gal Prosurf I plus 0.5gal/1000gal Prosurf II	American Energy Services	35.866	34.952	0.913	10.8	13.1	9.0	10.0	6224	6295	1.14	
	1 gal/1000 gal Cudd RFF-1	Cudd Pumping Services	34.931	34.873	0.058	0.7	17.2	43.3	54.4	6039	6693	10.83	Foamed
Control	Control No Gas, Caswell 2 Lower		42.937	34.441	8.496	100.0							
	Control After Gas, Caswell 2 Lower		36.391	34.697	1.693	19.9							

*Did not reach equivalent permeability value

**Primary product TR-A1 precipitated in brine, secondary product CatFoam used

Bold = Best performing products upon testing

Figure 1 - Barnett Shale Development Upside



Acreage Position within Potential Gas Productive Area

Wise	75,000
Parker	25,000
Johnson	75,000
Montague	?
Total	175,000

* 35 wells outside this area

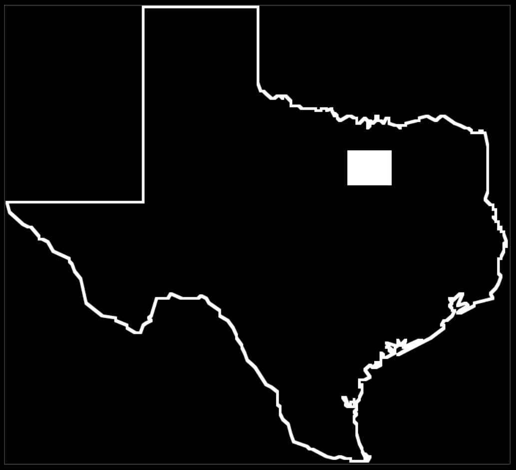
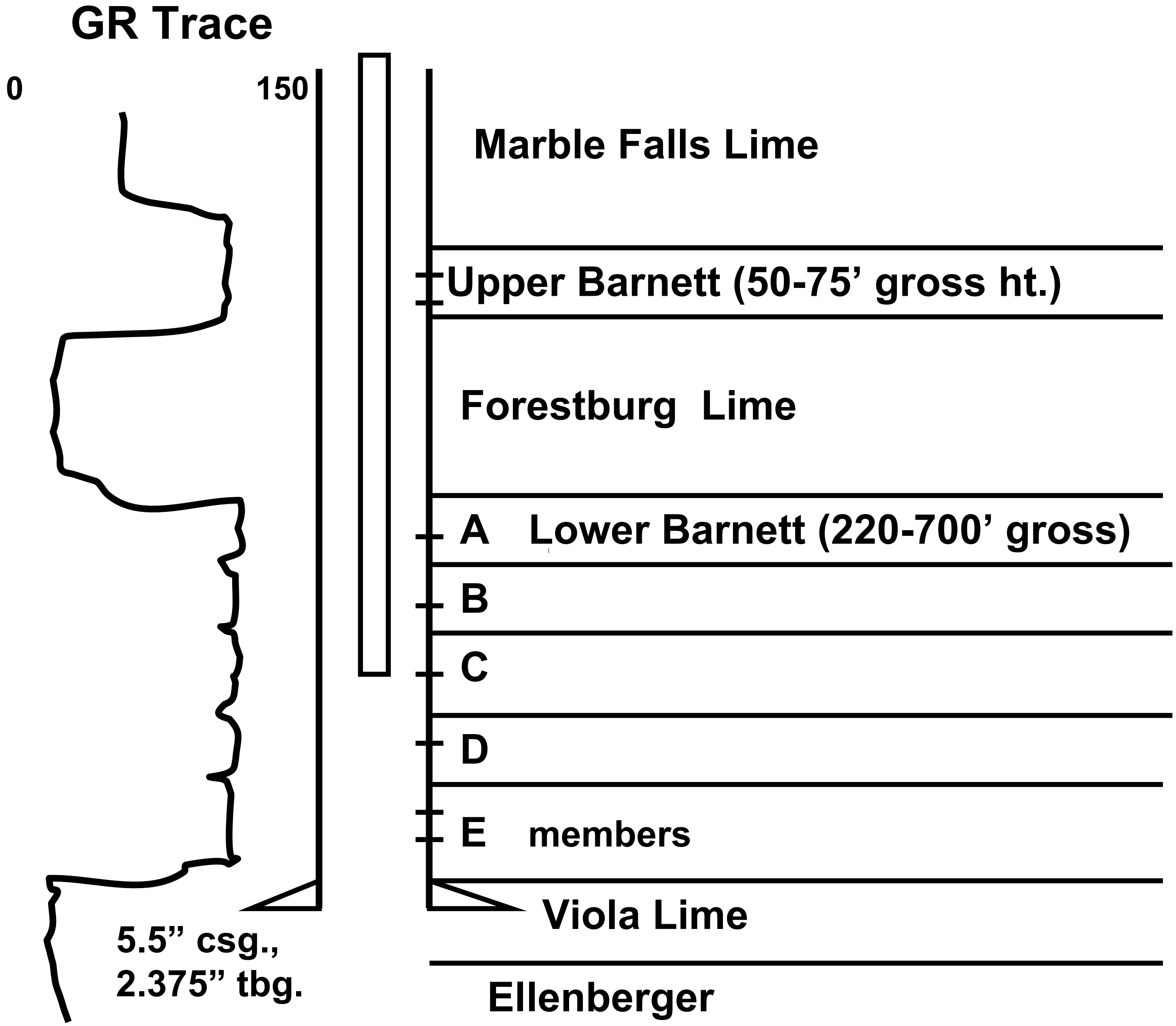


Figure 2 - Stratigraphic Column & Completion



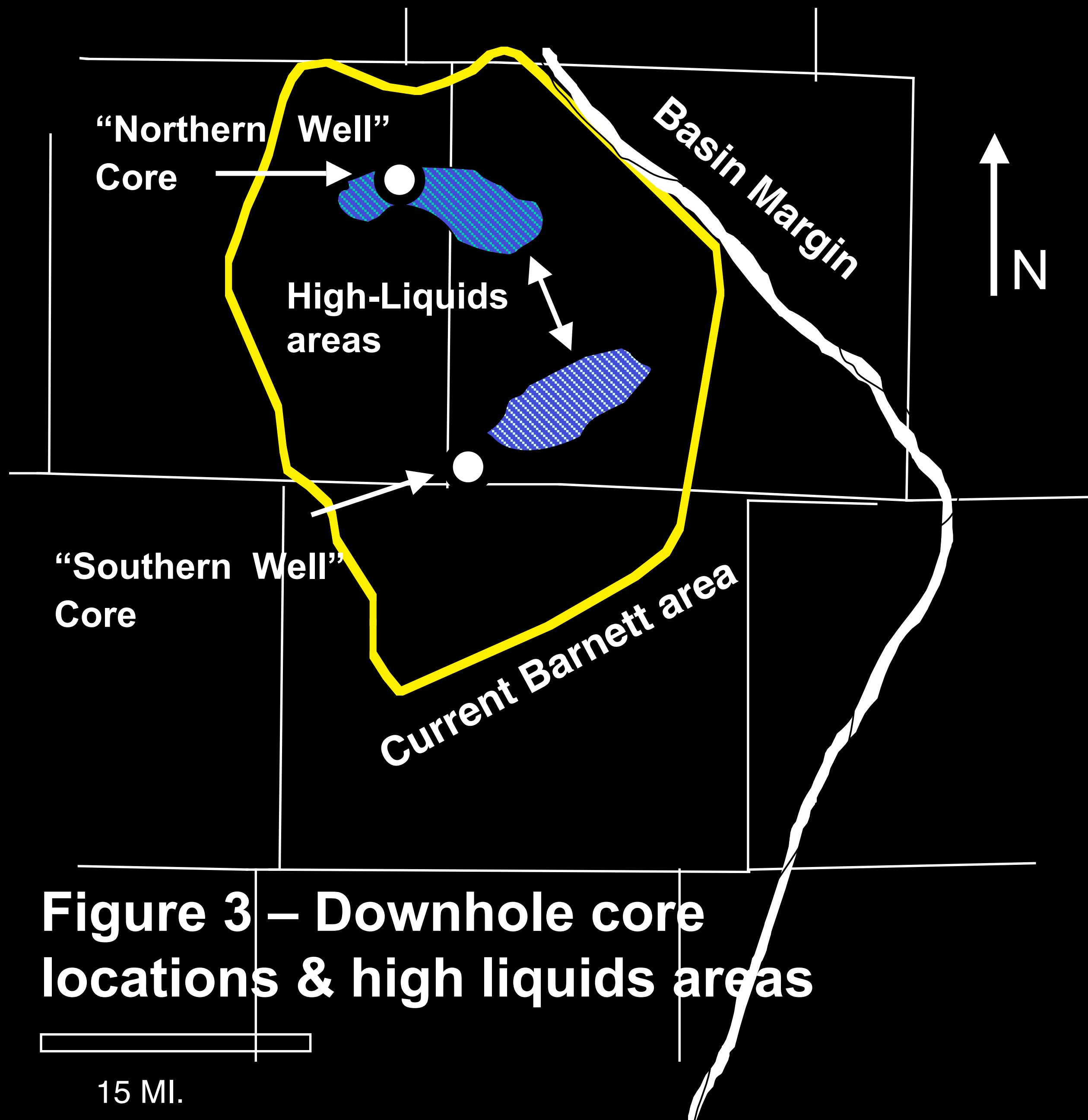


Figure 3 – Downhole core locations & high liquids areas

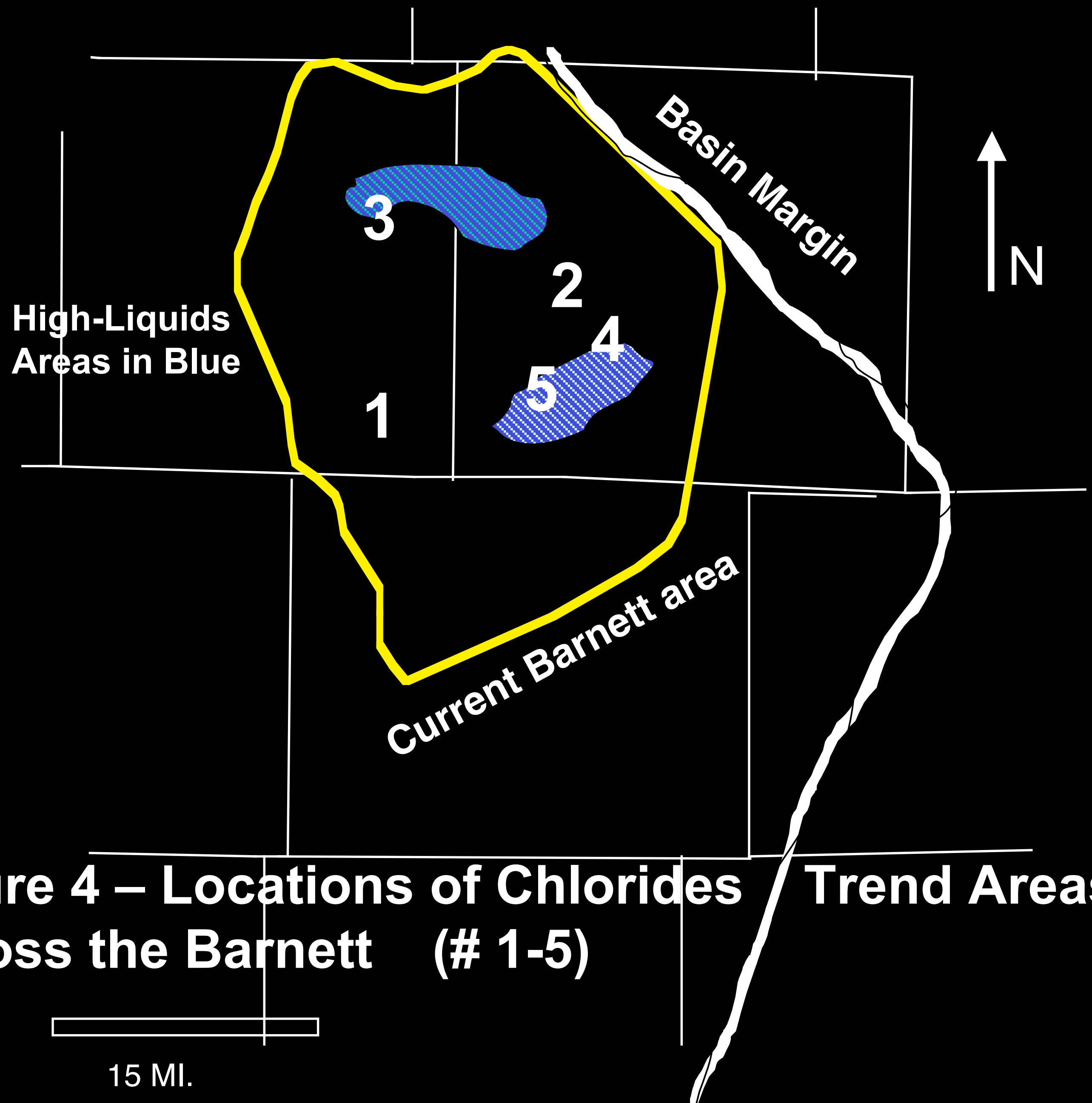


Figure 4 – Locations of Chlorides Trend Areas Across the Barnett (# 1-5)

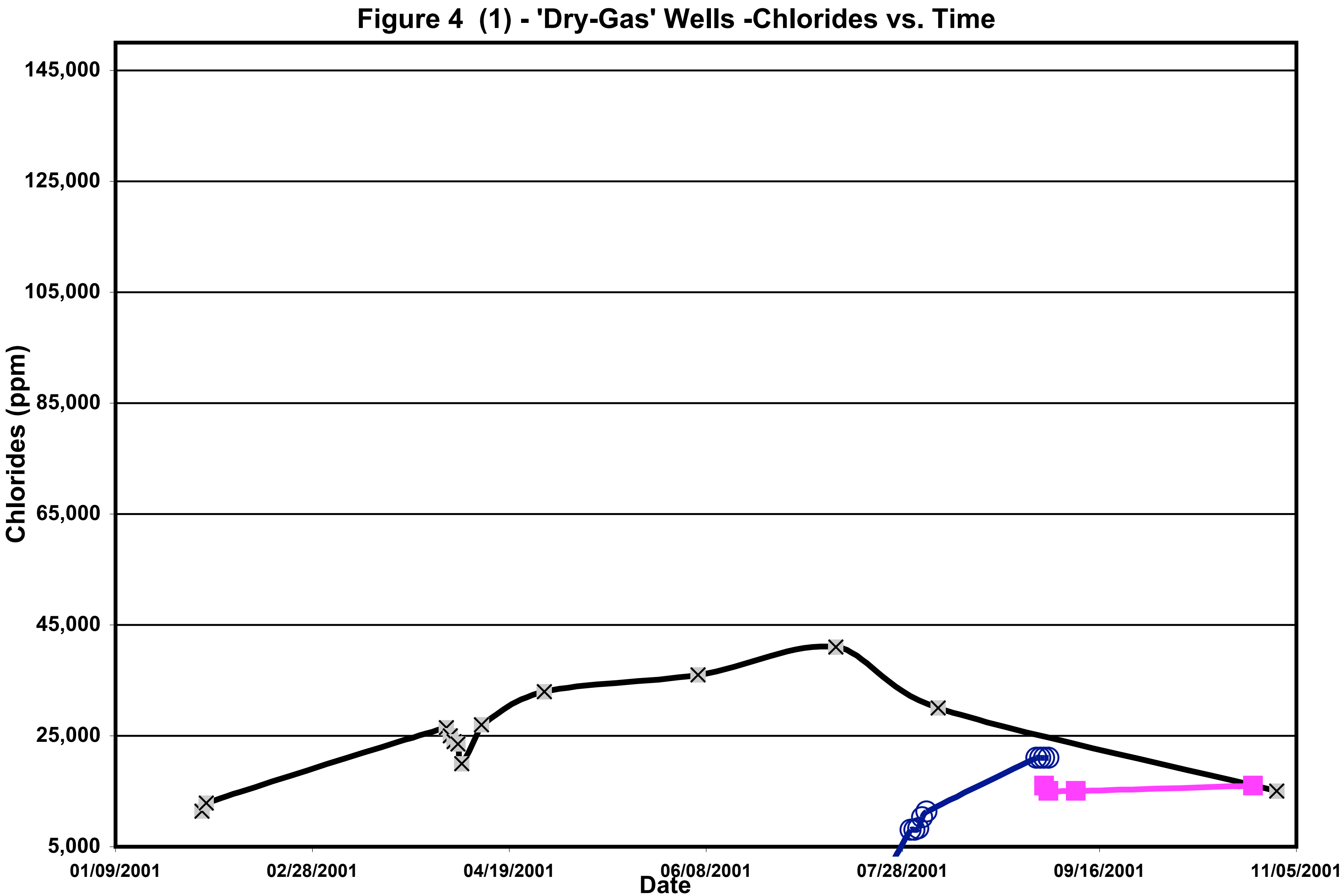


Figure 4 (1) - 'Dry-Gas' Wells -Chlorides vs. Time
145,000
125,000
105,000
85,000
65,000
45,000
25,000
5,000
Chlorides (ppm)
01/09/2001
02/28/2001
04/19/2001
06/08/2001
07/28/2001
09/16/2001
11/05/2001
Date

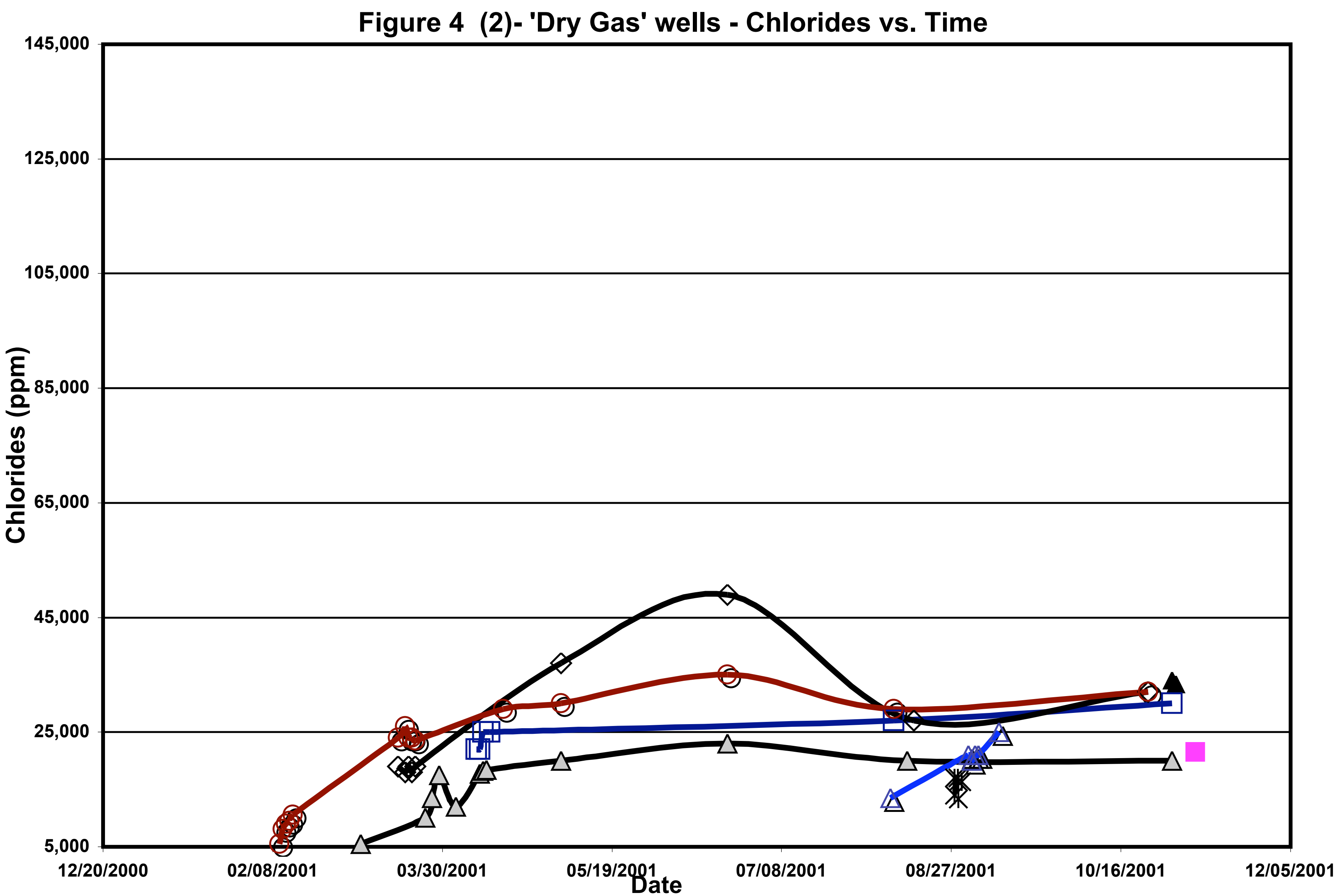


Figure 4 (2)- 'Dry Gas' wells - Chlorides vs. Time
Chlorides (ppm)
145,000
125,000
105,000
85,000
65,000
45,000
25,000
5,000
12/20/2000
02/08/2001
03/30/2001
05/19/2001
07/08/2001
08/27/2001
10/16/2001
12/05/2001
Date

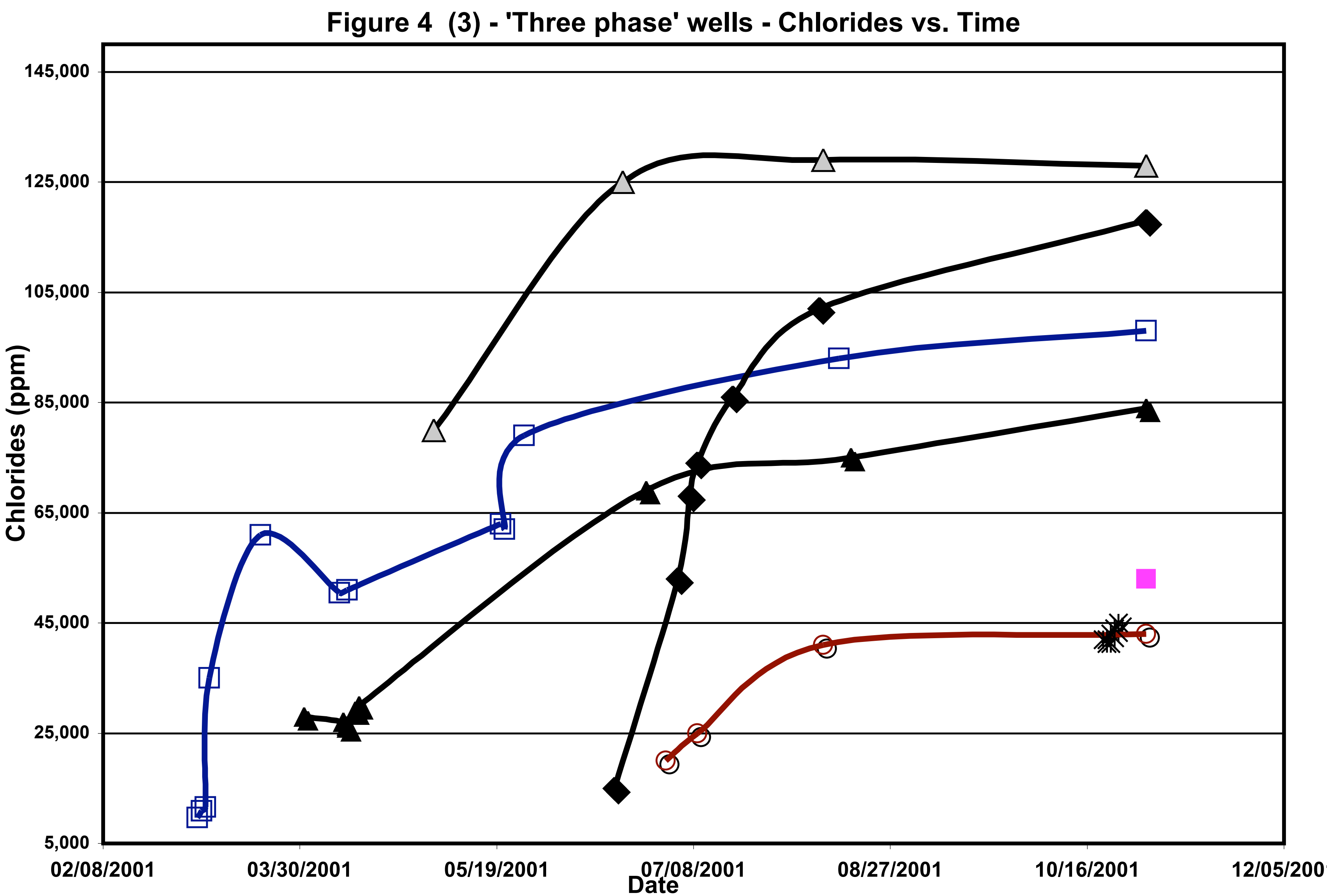
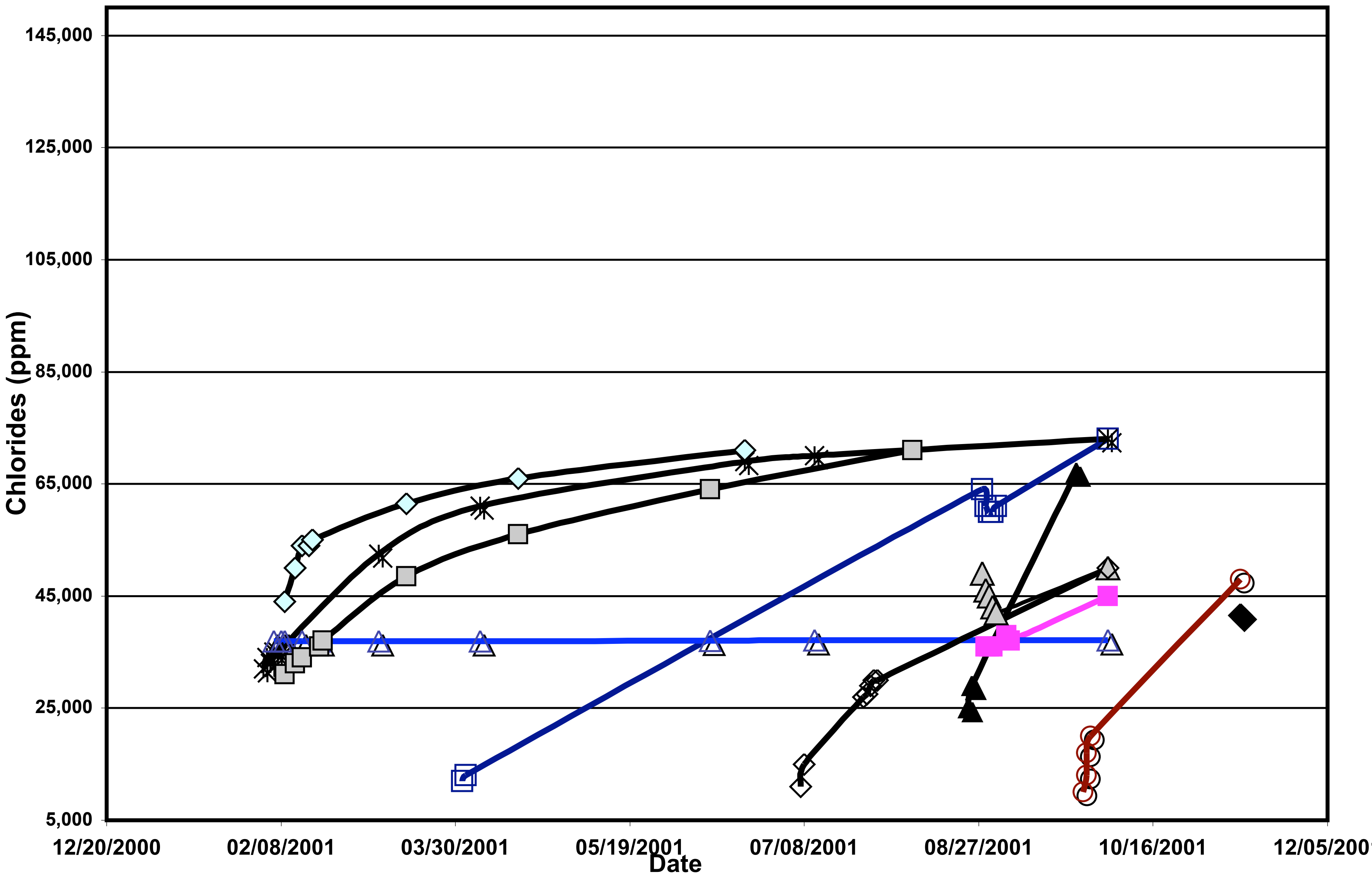


Figure 4 (3) - 'Three phase' wells - Chlorides vs. Time
Chlorides (ppm)
145,000
125,000
105,000
85,000
65,000
45,000
25,000
5,000
02/08/2001
03/30/2001
05/19/2001
07/08/2001
08/27/2001
10/16/2001
12/05/2001
Date

Figure 4 (4) - 'High Chlorides' wells - Chlorides vs. Time



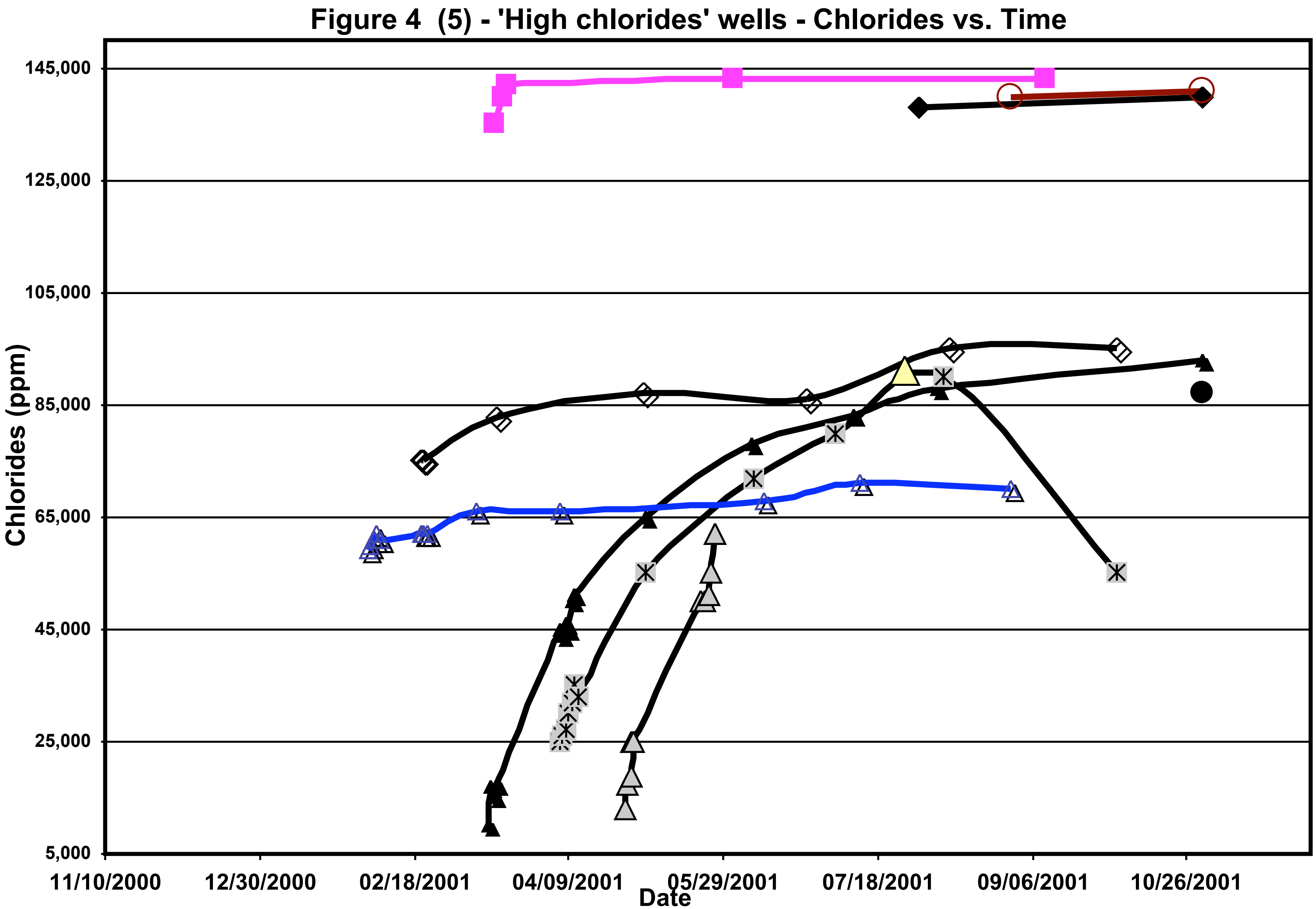


Figure 4 (5) - 'High chlorides' wells - Chlorides vs. Time
Chlorides (ppm)
145,000
125,000
105,000
85,000
65,000
45,000
25,000
5,000
11/10/2000
12/30/2000
02/18/2001
04/09/2001
05/29/2001
07/18/2001
09/06/2001
10/26/2001
Date

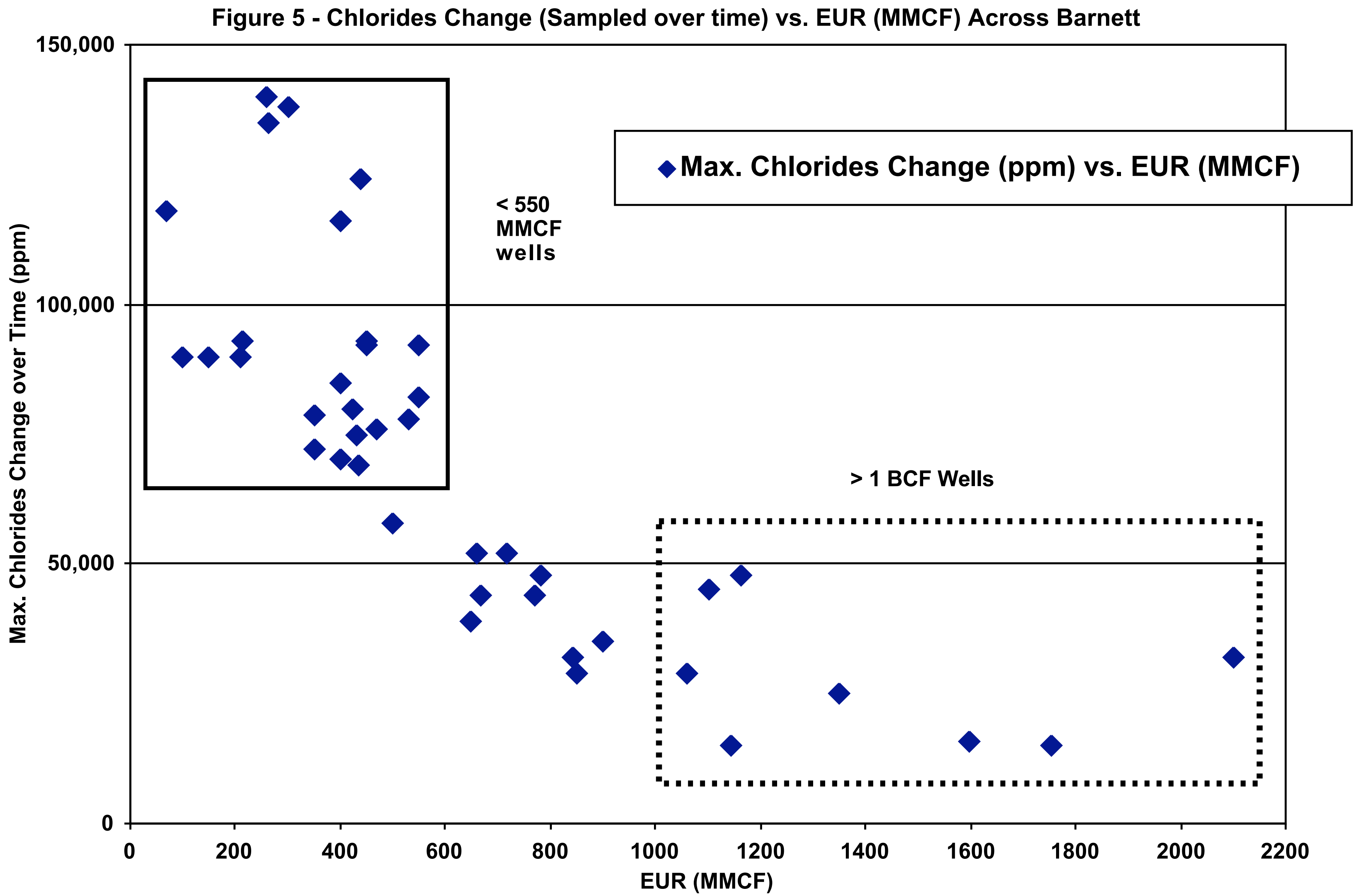


Figure 5 - Chlorides Change (Sampled over time) vs. EUR (MMCF) Across Barnett
Max. Chlorides Change (ppm) vs. EUR (MMCF)
< 550 MMCF wells
> 1 BCF Wells
150,000
100,000
50,000
0
0
200
400
600
800
1000
1200
1400
1600
1800
2000
2200
EUR (MMCF)
Max. Chlorides Change over Time (ppm)

Figure 6- Frac Flowback Water (bbl) vs. EUR (MMCF)

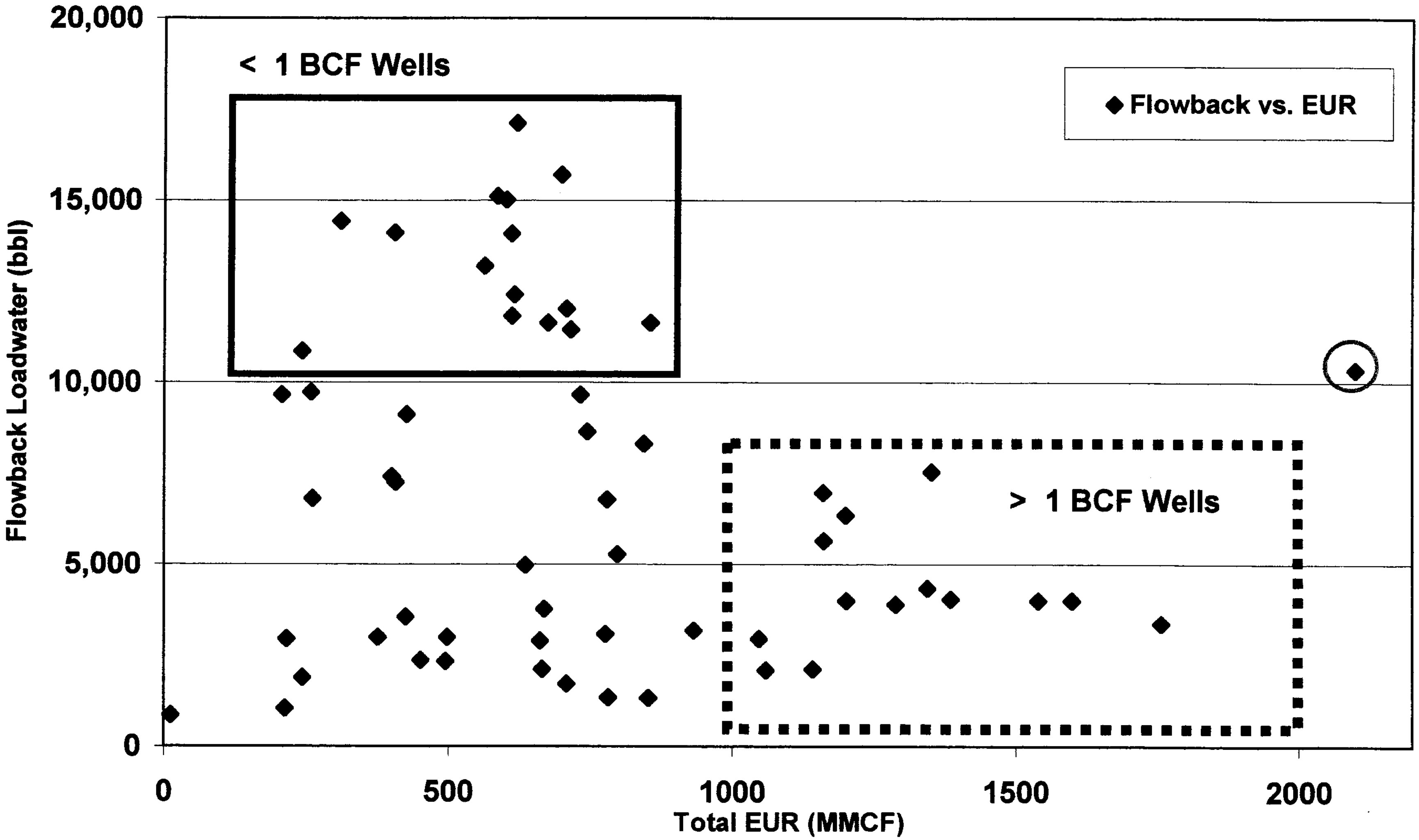
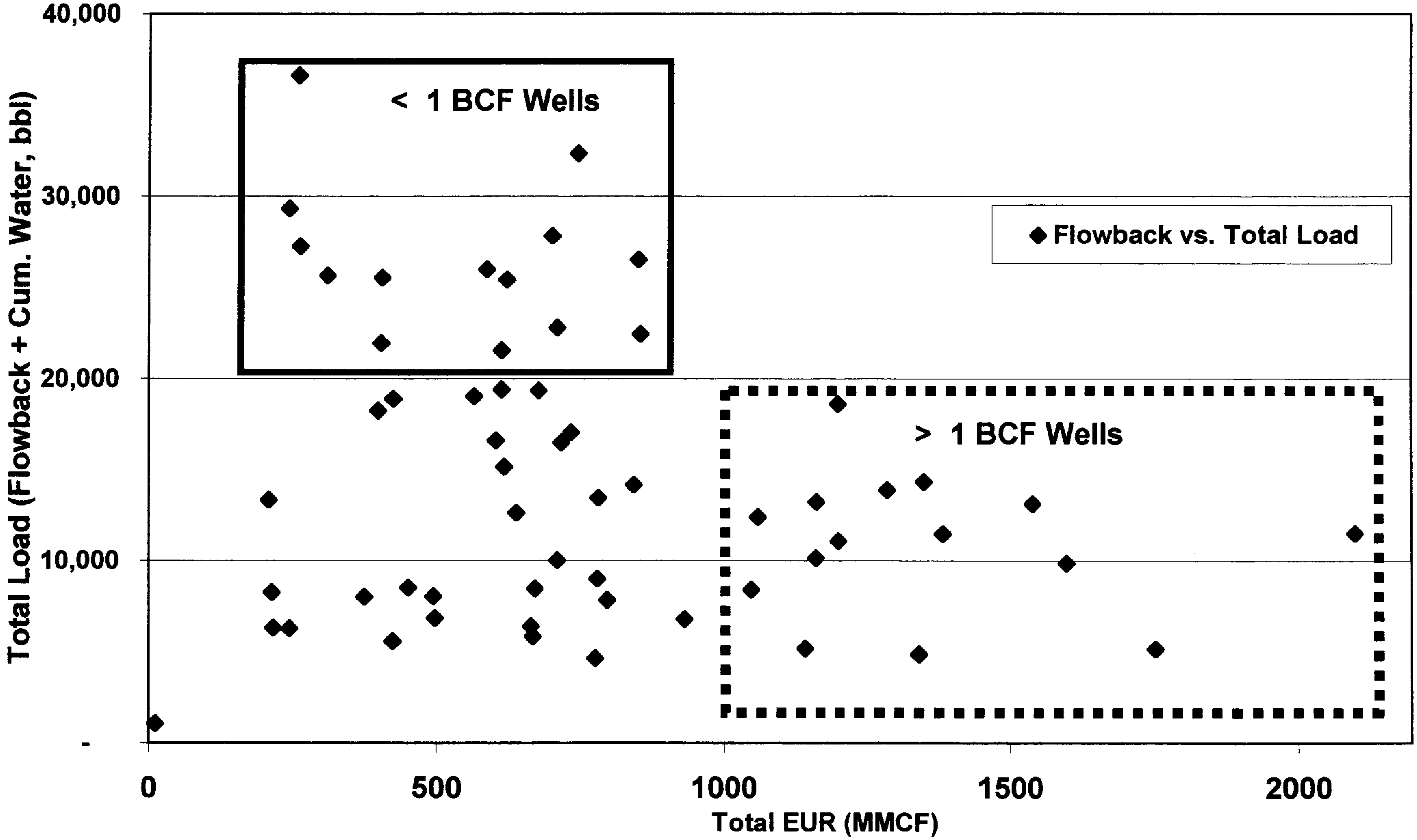


Figure 7 - Total Loadwater (Flowback + Cum. Water, bbl) vs. EUR (MMCF)



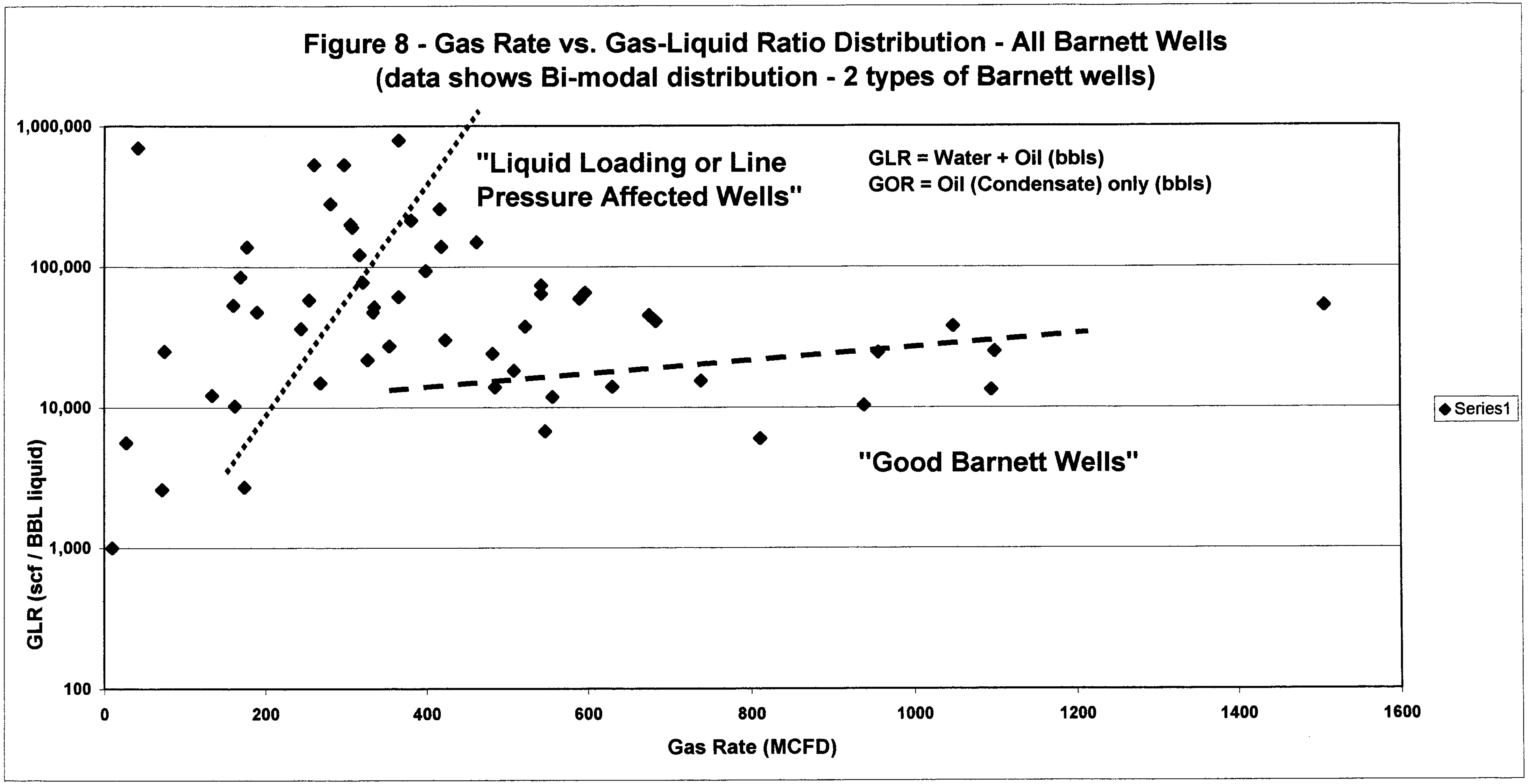


Figure 8 - Gas Rate vs. Gas-Liquid Ratio Distribution - All Barnett Wells
(data shows Bi-modal distribution - 2 types of Barnett wells)
"Liquid Loading or Line Pressure Affected Wells"
GLR = Water + Oil (bbls)
GOR = Oil (Condensate) only (bbls)
"Good Barnett Wells"
Series1
GLR (scf / BBL liquid)
Gas Rate (MCFD)
1,000,000
100,000
10,000
1,000
100
0
200
400
600
800
1000
1200
1400
1600

Figure 9 - Correlation between Days to Blowdown
(Line Pressure - #400 normalized) vs. EUR

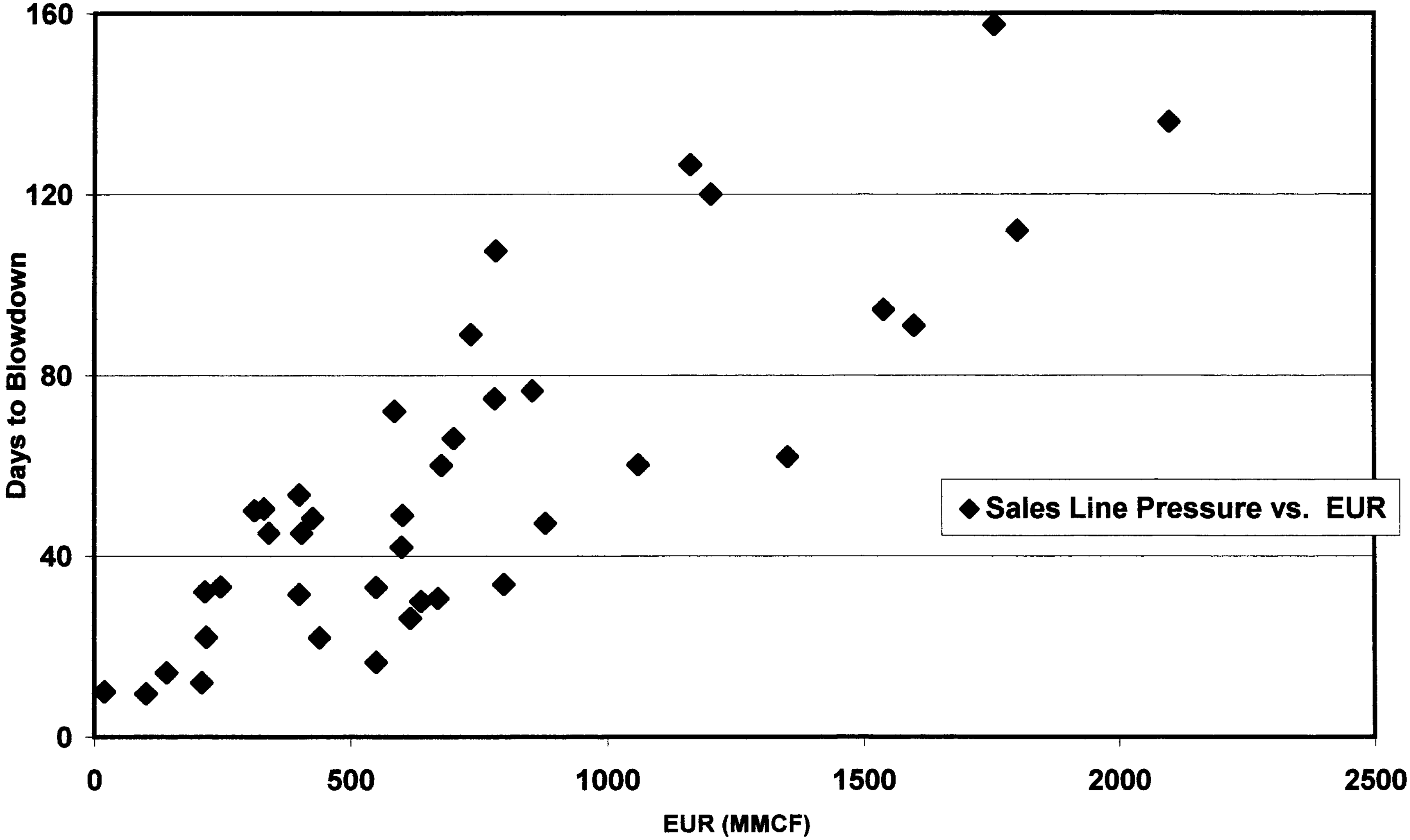


Figure 10 - ESP Co-Production, Testing Dewatering Below-Perfs

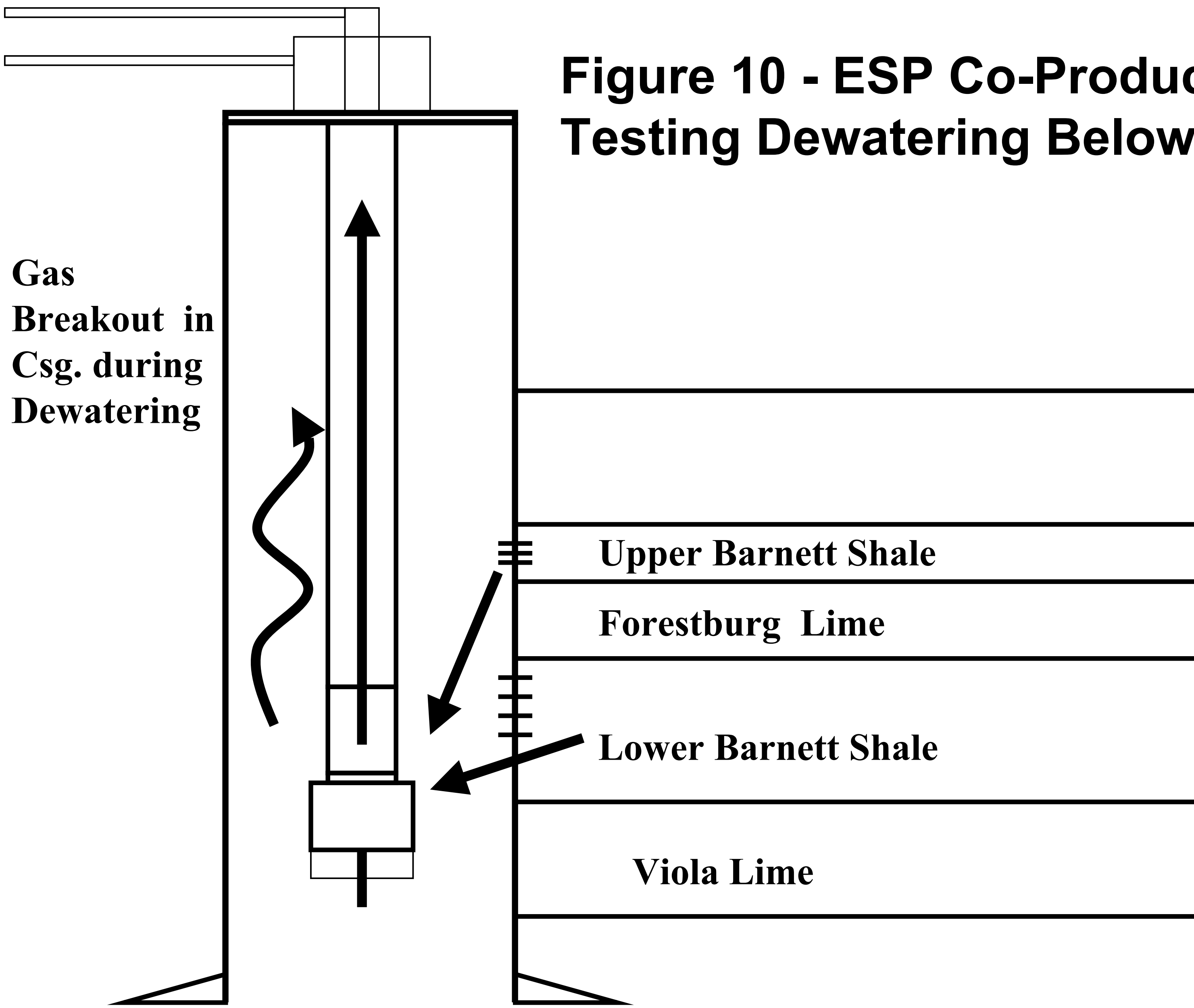
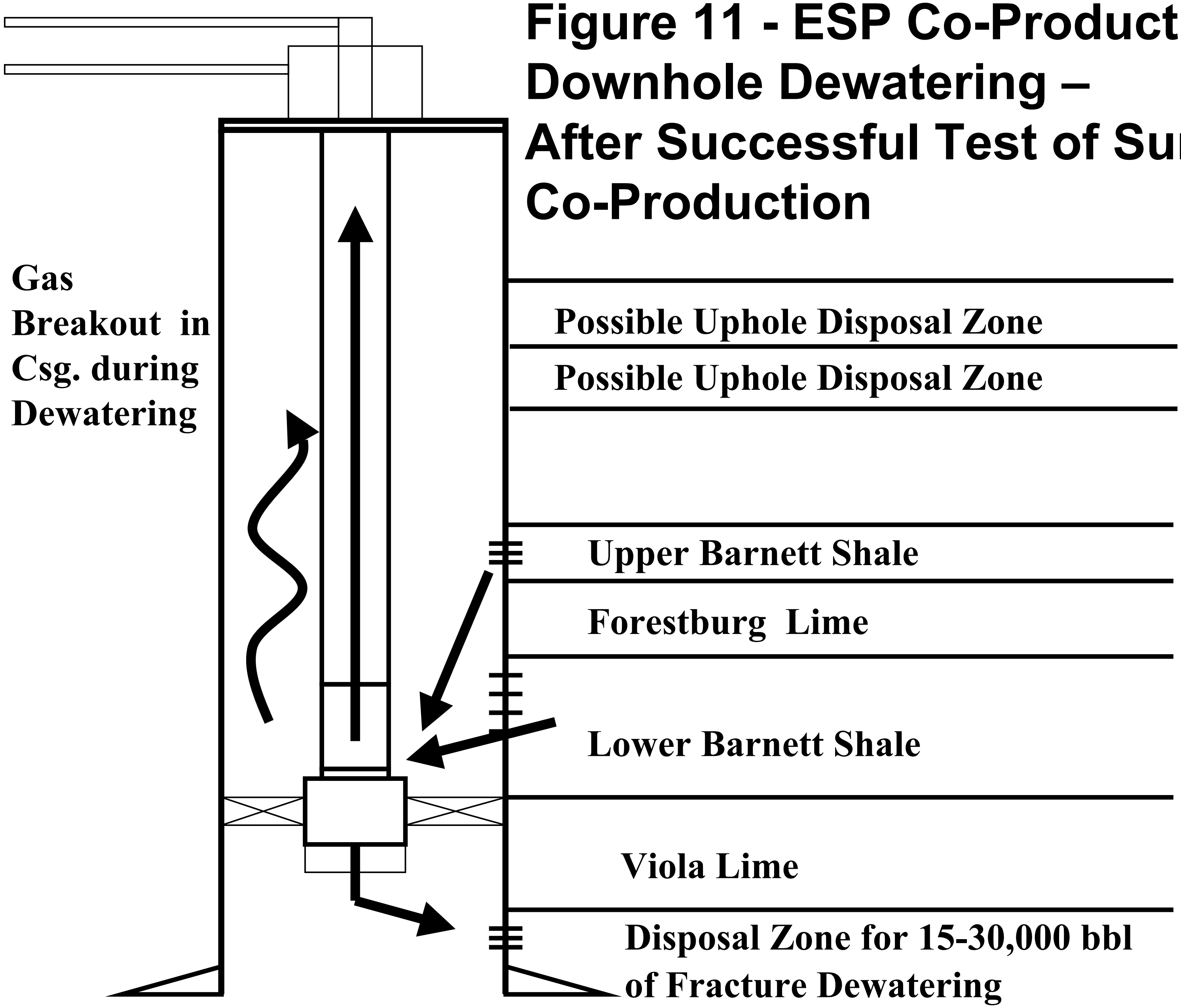


Figure 11 - ESP Co-Production Using Downhole Dewatering – After Successful Test of Surface Co-Production



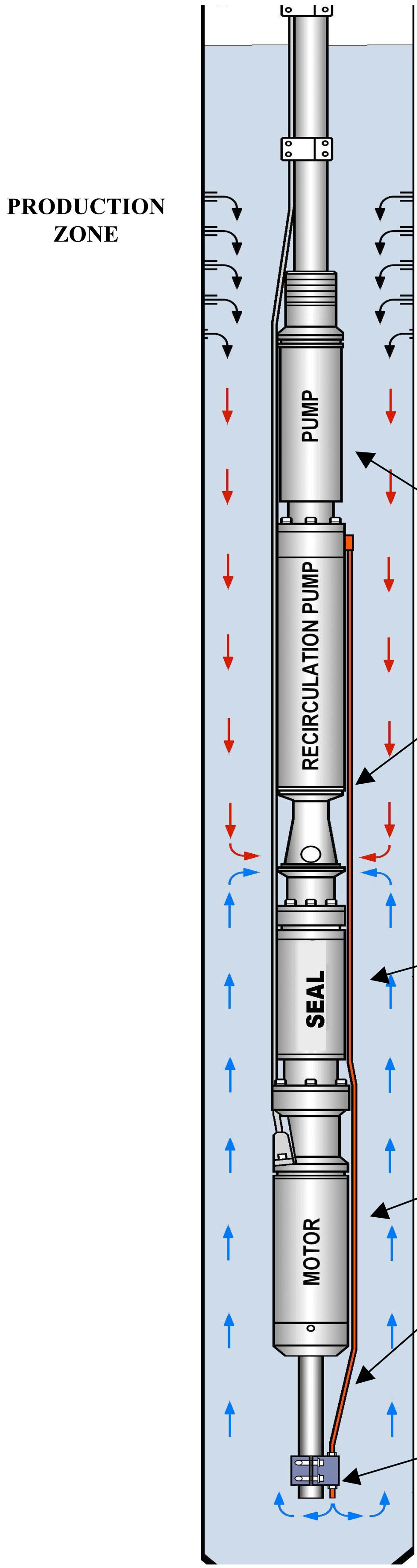


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FIGURE 12 – RECIRCULATION PUMP APPLICATION

PATENTED

PUMP
•SIZE LIKE A NORMAL INSTALLATION
•STANDARD OPTIONS CAN BE USED

RECIRCULATION SYSTEM
•INTAKE FOR BOTH PUMPS

SEAL
•CONVENTIONAL

MOTOR

RECIRCULATION TUBE

TUBING CLAMP

Recirculation Pump System used to:

- maximize well drawdown
- minimize gas interference
- improve motor cooling in low volume wells
- provide an alternative to slim line equipment

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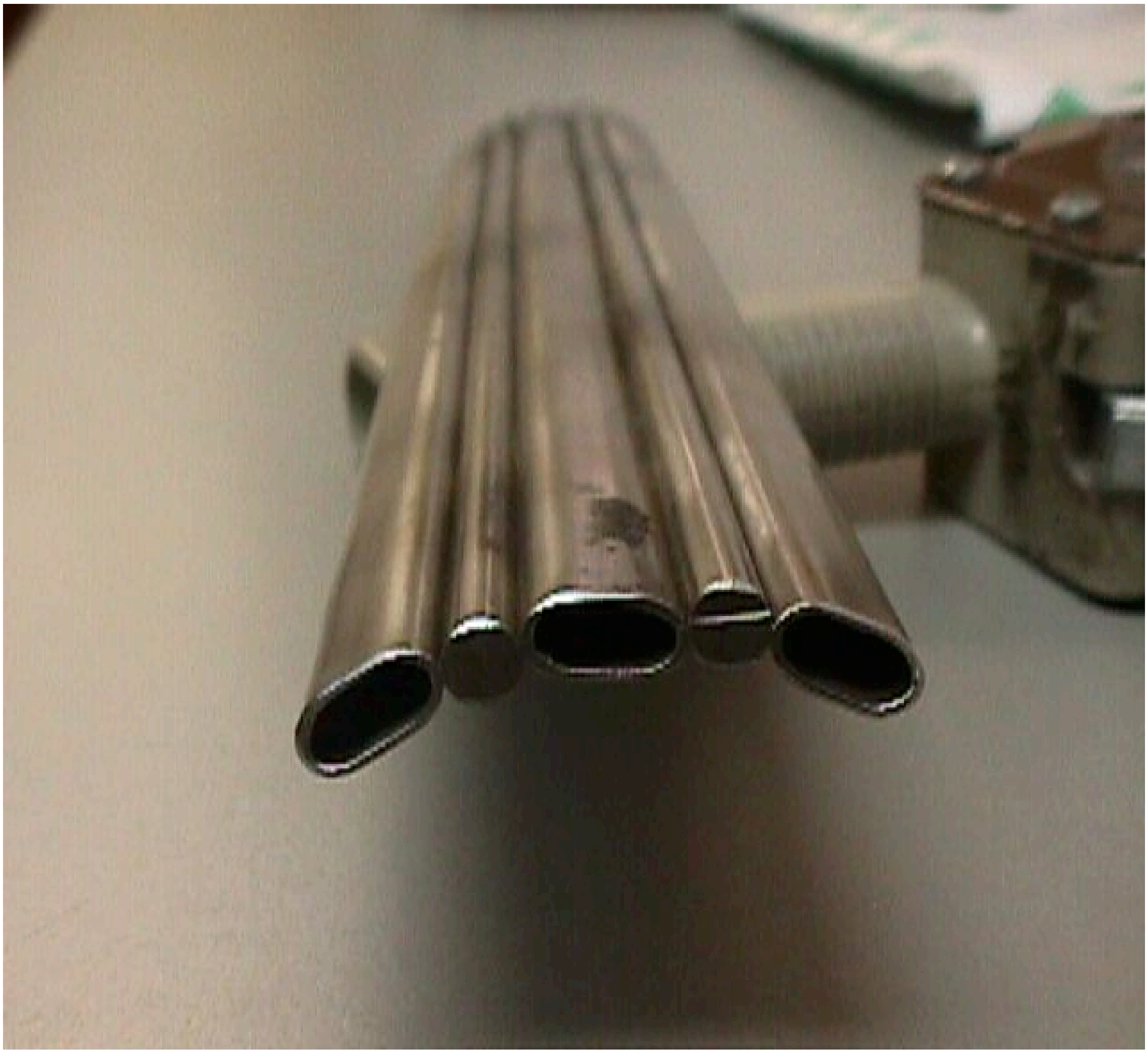


Figure 13
Confinement Cell Used For Flow Studies - Stim-Lab[tm]

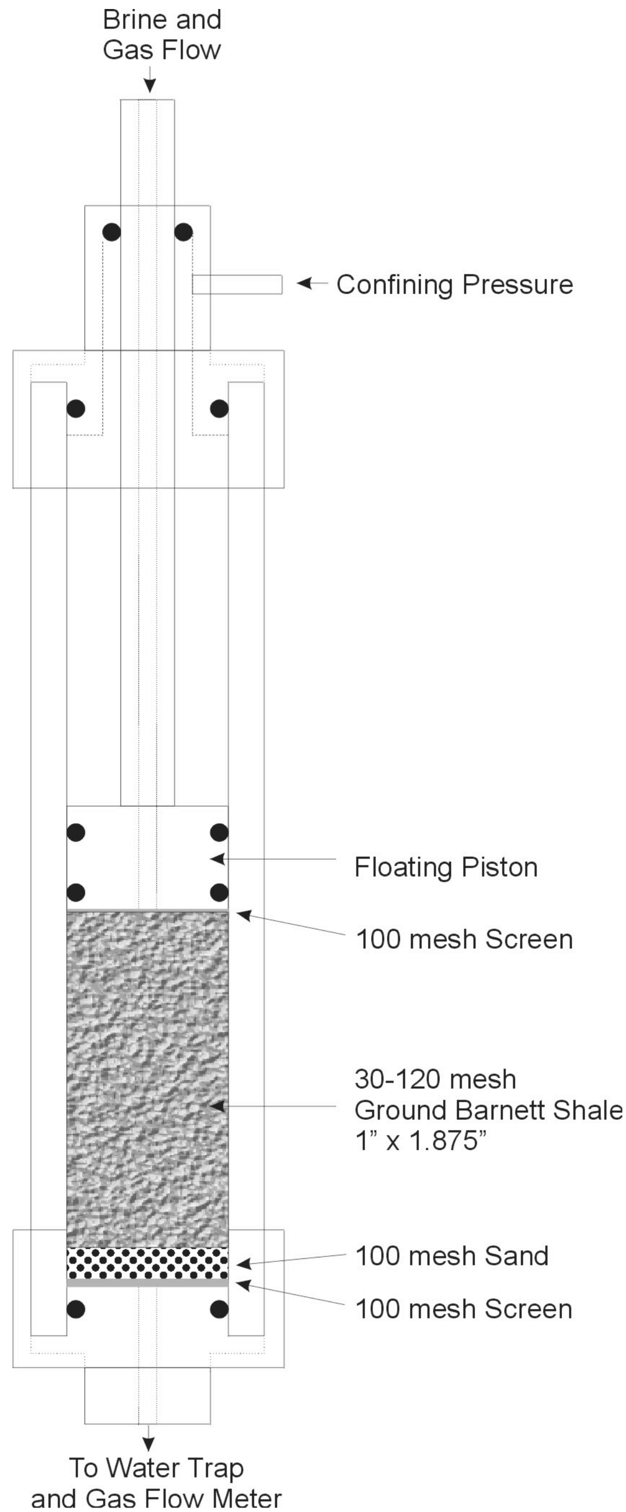
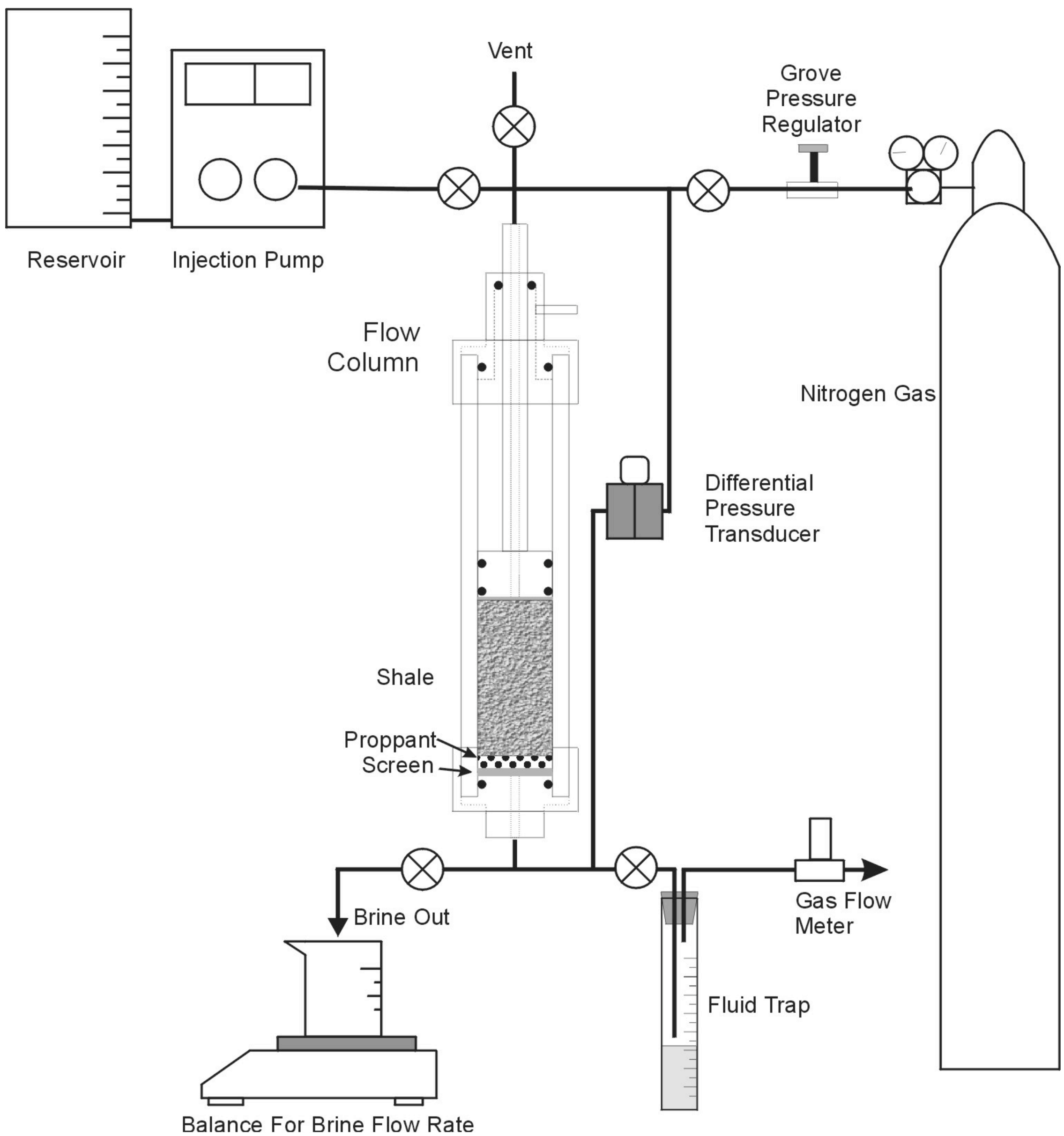


Figure 14
Equipment Flow Diagram for Flow Studies - Stim-Lab™



Appendix I

Capillary Suction Time Tests

Capillary suction time (CST) tests are performed using the Fann model 44000 CST timer. CST tests measure the retention of fluid by a slurry of the ground formation rock in the fluid to be evaluated. The slurry is placed in a funnel atop a chromatography paper. The timer measures the time for the fluid to be extracted from the slurry by adsorption into the chromatography paper. Sensors start the timer when the fluid reaches approximately 0.25" from the funnel and stop the timer at a distance of 1" from the funnel. Fluids that disperse clays in the formation slurry form a clay colloid (mud), which resists extraction of the fluid, and give long CST times. Fluids that do not form a colloid are easily extracted and give short CST times. A correction is made in the measurement for the viscosity of the fluid and fluid/paper interactions for comparison of fluids with the same core material. This is done by measuring the time for the fluid alone without formation material to be adsorbed. This is called the blank time. Three CST times are measured for each rock/fluid combination and averaged. The data is presented as a ratio of the CST time minus the blank time divided by the blank time. High CST ratios indicate increased colloid formation and more potential formation damage. Value differences for CST ratio of less than about 0.5 are usually within experimental error and are not considered significant. Magnitude of the value for CST ratio will vary depending on grain size distribution, and the amount of clay and silt within the rock sample. Therefore, the values cannot be compared between rock samples except in relative terms to two control fluids. These are usually a high saline solution, such as 6% KCl, and freshwater.

Formation samples are prepared by crushing the rock to less than 70 mesh in size. The crushed rock is then mixed with the fluid to be tested at a ratio of 1 gram to 20 ml. The slurry is mixed rapidly for 15 -20 minutes. A 5 ml portion of the slurry is extracted and placed into the CST funnel with a new sheet of paper. The CST time is recorded and the measurement made two more times with fresh paper for each measurement. The times are averaged. A blank time is measured for each fluid in triplicate for each box of chromatography paper. The blank time is then used in the calculation of the CST ratio.

Flow Back Additive Studies

Barnett shale matrix permeability is too low to allow for flow studies. Primary production is believed to be from natural fractures. While fracture flow studies are possible, more core material is required to conduct these type studies than what was available. Therefore, flow studies were conducted using ground material sieved to 35 –120 mesh size range and packed into a confined flow chamber as shown in **Figure 13**. To allow for sufficient comparison tests with the various products, core samples from the Southern Well were combined to give a composite sample. Table 1 gives the samples that were combined. All samples were from the Lower Barnett. Additional samples from the A and B sub zones of the Lower Barnett from the Northern Well were combined as well as samples from the C, D and E sub zones. These were used following the initial screening with the Northern Well samples to verify the applicability of the best performing products to shale samples from a different area. The material from each sample was ground with a mortar and pestle and placed on a sieve stack of a 35 mesh sieve over a 120 mesh sieve over a pan. Material that would not pass through the 35 mesh sieve was returned to the mortar and reduced further. Material passing the 120 mesh sieve was retained and used for x-ray diffraction analysis.

Packing was conducted by filling _ of the chamber with 50,000 ppm (Cl^-) brine. The brine was selected based on typical produced water used in water fracs in the Barnett. The brine formulation is given in Table 2. In the bottom of the chamber was a 100 mesh stainless steel screen. 5 grams of 80-120 mesh sand was added and the chamber tapped to settle the sand. On top of the sand was added 30 grams of the Barnett shale mixture. The chamber was again tapped to settle the ground shale. The plunger was placed in the chamber and the top cap affixed. The piston was then pressured to 50 psi to confine the pack. The pack was then allowed to set overnight to hydrate the shale and stabilize.

The flow chamber was plumbed to the flow system diagramed in **Figure 14.** The pack was flooded with the 50,000 ppm brine from the top downward at 10 ml/min until the differential pressure, as measured by the differential pressure transducer, stabilized indicating that the pack was settled and stabilized. An electronic balance at the exit was used to verify flow rate.

Brine flow was stopped and the vent valve at the top of the pack was opened and the brine allowed to drain from the pack into a trap. Methane gas was then flooded through the pack at constant pressure of 3 psi and the gas flow rate monitored with a mass flow meter on the other side of the water trap. Gas flow was conducted until the flow rate at 3 psi was constant. Gas flow was then stopped. The gas permeability was then calculated and the amount of water produced measured.

The brine and gas flow were then repeated with the flow-back enhancement additive placed into the brine solution at the supplier's recommended concentration. The amount of water produced with gas flow and the gas permeability following the additive treatment were measured and compared to gas displacement without additive.

Finally the flow chamber was opened and the sand/shale pack extruded into a tared weigh boat. The weight of the material was measured. The pack material was then placed in a 200 ºF oven to dry. The dry weight was then measured. The weight difference gave the amount of water remaining in the pack. These weights were then compared between products and a control where no treatment was performed.