Section 3
Dealing with High Water Production During Primary Production

- Water shut-off treatments using gelled polymers
  - General information
  - Candidate selection
  - Treatment sizing
  - Preparation prior to pumping
  - Placing treatment
  - Case studies

General Information

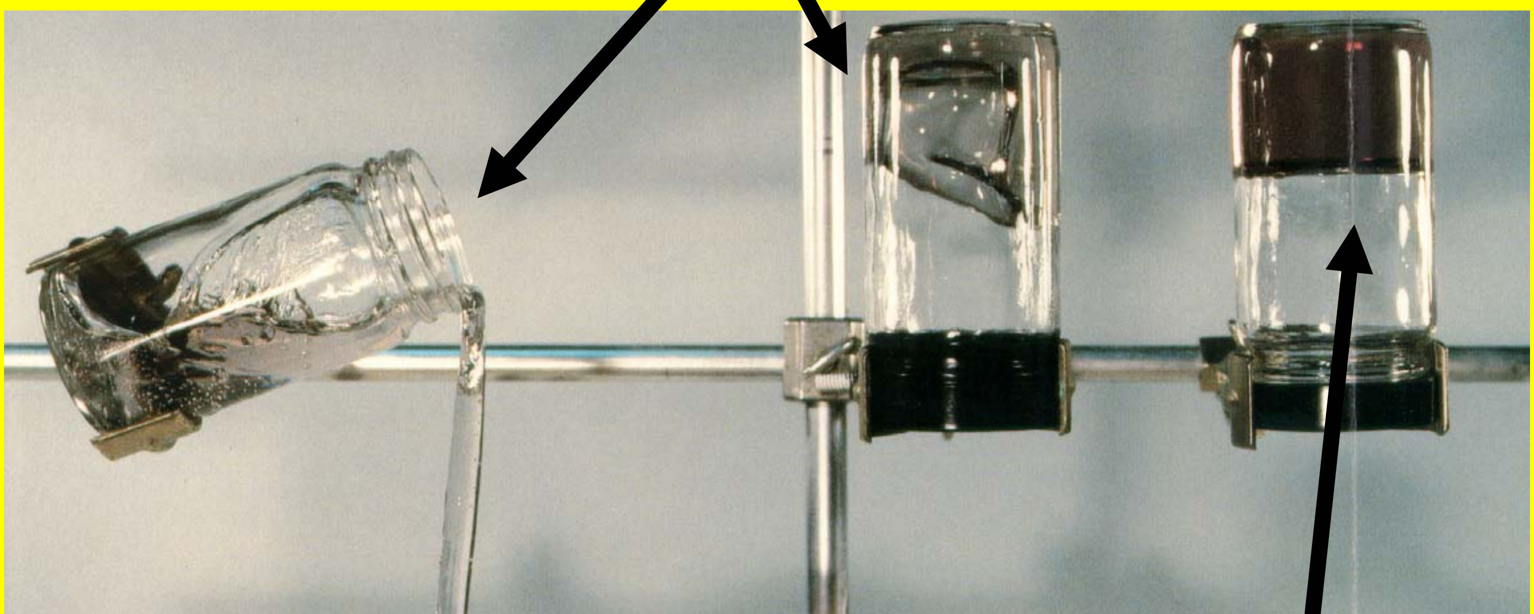
- Majority of polymer treatments to control water production in producing wells are performed in fractured carbonate/dolomite formations associated with natural water drive
- Gelled polymers created when dry polymers is mixed in water and crosslinked with a metal ion (usually chromium triacetate or aluminum citrate
- Gelation is controllable, ranging from a few hours to weeks
- Slower gelation time allows for more volume and deeper placement

General Information (cont.)

- Different polymer systems available from different service providers
- Recent successful treatments in the midcontinent have used the MARCIT^{sm} technology developed by Marathon Oil Company
- MARCIT^{sm} is acronym for MARathon Conformance Improvement Treatment
- Service company experience seems to be dominant factor in estimating how a particular formation in a given area will respond to gelant injection

MARCIT Technology Gels

Flowing **MARCIT-CT**
for Areal Conformance



MARA-SEAL
for near wellbore shut-off

MARATHON

Applications

Near wellbore matrix gels

MARA-SEAL

- Chemical Liner to Seal Open-Hole
- Zone Abandonments
- Behind Pipe Channels
- Casing Leak Repairs

Far wellbore fracture gels

MARCIT-CT

- Injection Wells Improved Sweep (*in naturally fractured or vuggy reservoirs)*
- Producing Well for Reducing Water (*in naturally fractured or vuggy reservoirs)*

MARCIT^{SM} Technology

- Cr(III)carboxylate/acrylamide-polymer
- Chromium acetate the preferred crosslinker in most applications but **not chromium 6**
- Developed by Marathon in mid 1980's

✓ ***over $30 million spent in development***
✓ ***over 162 ++publications on the technology***

Advantages of the MARCIT^{SM} Technology

- Cr(III) is not a serious problem to safety and environment, unlike Cr(VI)
- Not a sequentially pumped process
- Single Clear fluid
- Insensitive to interferences in chemistry due to produced water and other contaminant
- Gel QC is highly manageable

Licensed Service Providers

- Gel Technologies Corporation
- TIORCO Inc.
- Schlumberger Well Services

General Information (cont.)

- Be prepared to alter original design based on ability of a formation to accept a viscous fluid
- Formation injectivity test is important
- Creating a pressure response is most important indicator of potentially successful treatment
- Treatment monitored using Hall plot
- Slow steady pressure increase during pumping indicates
  - Formation is reaching fill-up
  - Reservoir temperature is causing polymer to crosslink and build viscosity

General Information (cont.)

- Pressure response is product of
  - Polymer volume
  - Injection rate
  - Gel strength
- Altering any or all of these factors can improve success if reservoir resistance is not seen during pumping
- Injection rates increased at beginning of treatment to determine how easily formation accepts viscous fluid
  - Research and field experience show higher pump rates improve effectiveness of treatments in carbonates exhibiting secondary permeability and porosity
  - Also reduces field time which means lower cost

General Information (cont.)

- Increasing gel strength typically used at midpoint of treatment and is accomplished by
  - Accelerating crosslinking
  - Increasing polymer concentration
  - Using higher molecular weight polymer
- Accelerated crosslinking accomplished in the MARCIT^{sm} system by adding chrome chloride to the chromium triacetate
  - Can form mature gels in 4-6 hrs compared to normal time of 16-18 hrs at 90^{o}F
  - Advantage is less gel volume (lower cost)
  - Disadvantage is may cause gel to prematurely set in or near the wellbore

General Information (cont.)

- Increasing polymer concentration
  - Improves gel strength
  - 4000 ppm gel contains 1.4 lbs of polymer per barrel of mix water
  - Increasing concentration to 5,500 ppm adds 0.52 lbs per barrel which is nominal chemical cost
  - Advantage is stronger gel that crosslinks quicker
- Molecular weight important part of gel strength
  - Most treatments utilize medium molecular weight (4-8 million) polyacrylamides, can be used in high perm matrix and small fracture systems

General Information (cont.)

- Increasing polymer volume
  - Typically recommended by service companies if Hall plot shows slight increase of pressure near end of treatment
  - Advantage is greater in-depth reservoir penetration
  - Disadvantage is increased treatment costs due to longer pump times and additional chemicals

Candidate Selection

- Best candidates are shut-in wells or wells producing at or near their economic limit
  - Benefit most from a successful treatment
  - Little at risk if treatment fails (other than treatment cost)
- Significant remaining mobile oil in place
- High water-oil ratio
- High producing fluid level
- High initial productivity

Candidate Selection (cont.)

- Wells associated with active natural water drive
- Structural position
- High permeability contrast between oil and water-saturated rock (i.e., vuggy and/or fractured reservoir)
- Successful treatments have been conducted in both cased and open hole completions

Treatment Sizing

- Only empirical methods exist at this time
- Experience in a particular formation is beneficial
- In many instances larger volume treatments appear to decrease water production for longer periods of time and recover more incremental oil
- Rules-of-thumb
  - Two times the wells daily production rate as a minimum
  - Daily production capacity at maximum drawdown
  - Daily production rate as minimum in lower fluid level wells

Preparation Prior to Pumping

- Ensure wellbore is clean
- Acidize if necessary (typically 350-500 gal 15% acid, pump away with water)
- Establish maximum treating pressure
- Run step rate test to determine parting pressure, if necessary
- Select acceptable source of water to blend and pump treatment

Preparation Prior to Pumping (cont.)

- Have service company test water’s compatibility to form desired gels
- Select polymer-compatible biocide for the mix water (typically 5-10 gal per 500 bbls of mix water)
- Set tubing and packer above zone to be treated

Placing the Treatment

- Use stages of increasing polymer concentration
- Inject at similar to the normal producing rate
- Keep treating pressure below parting pressure
- Changing conditions during treatment may warrant design changes during pumping
- Over displace treatment with water or oil
- In some instances a rapid pressure response early in the treatment is a danger sign the treatment may not be successful

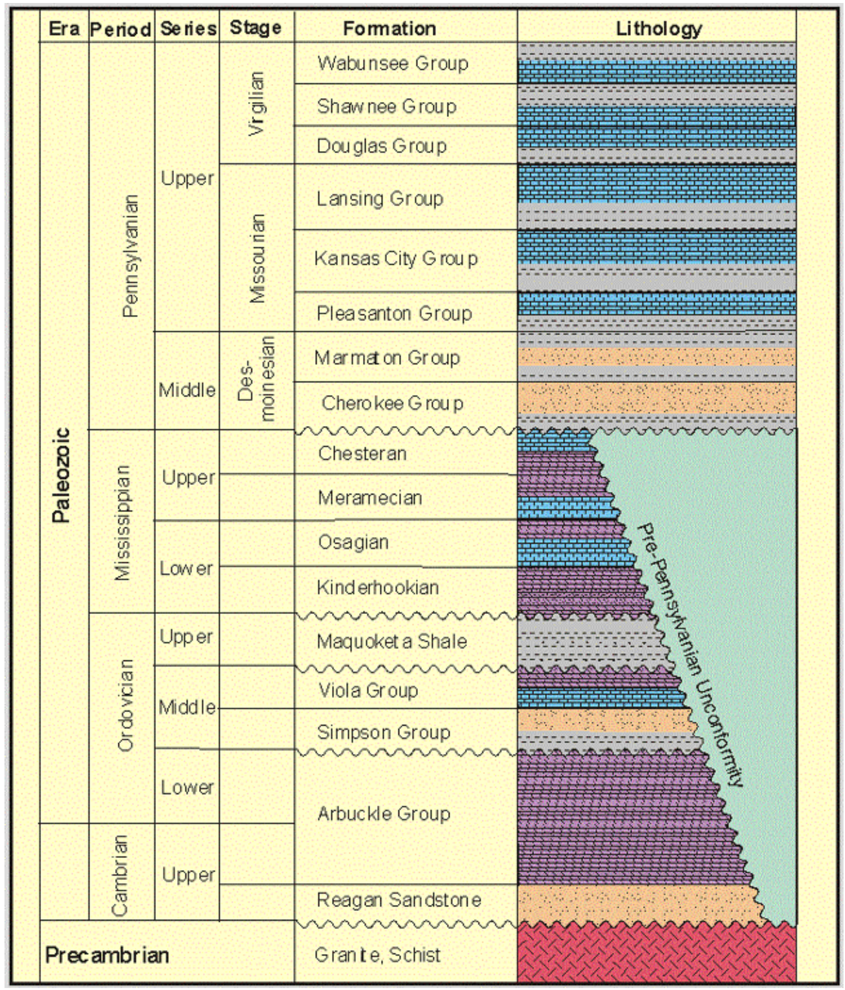
Case Studies

- Arbuckle treatments in Kansas
  - Approx. 200 MARCIT technology polymer jobs pumped in Arbuckle since 2001
- Oklahoma treatments

Common Perceptions About Arbuckle Strata in Kansas

- **Predominantly shallow-shelf dolomites**
- **Fracture-controlled karstic reservoirs with porosity and permeability influenced by basement structural patterns and enhanced by prolonged subaerial exposure**
- **Process of dolomitization also enhanced porosity**
- **Most of the oil and gas zones are contained in the top 25 ft.; some down to 50 ft.**
- **Reservoirs typically visualized as an oil column on top of a strong aquifer**

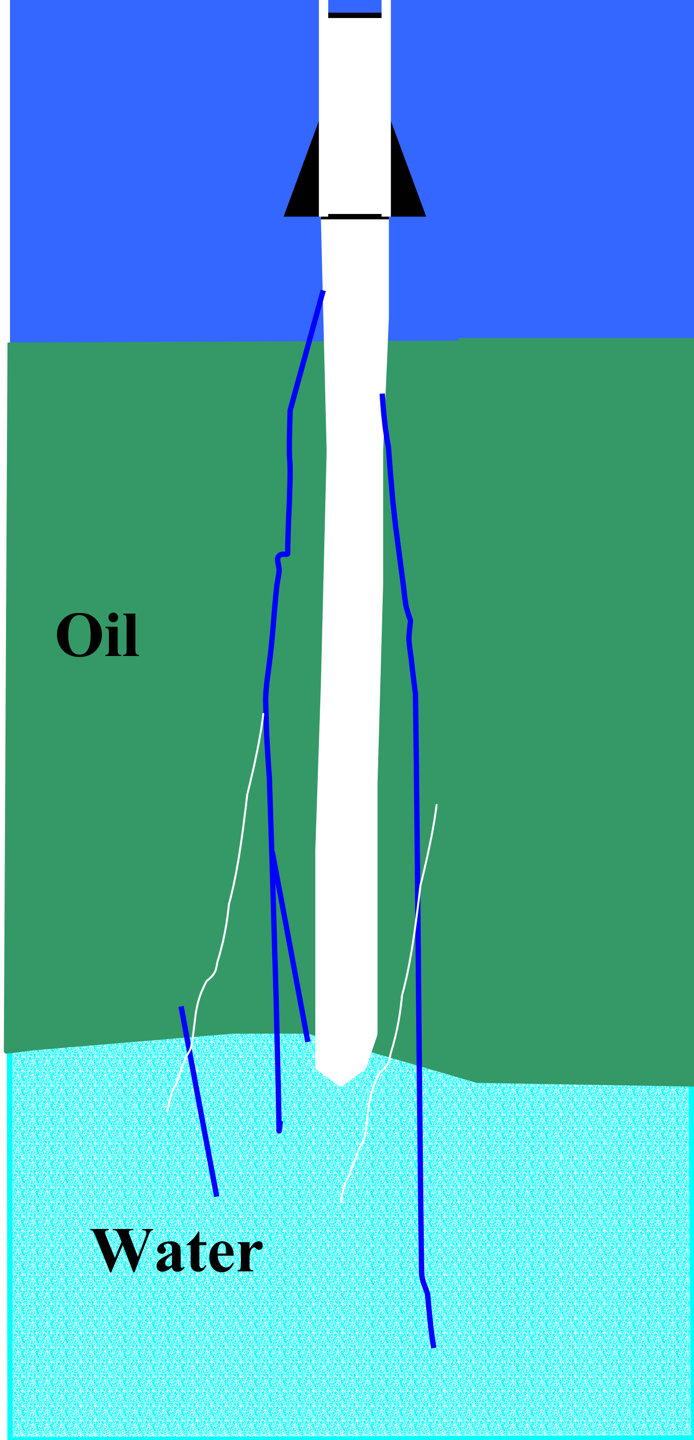
Stratigraphic Column

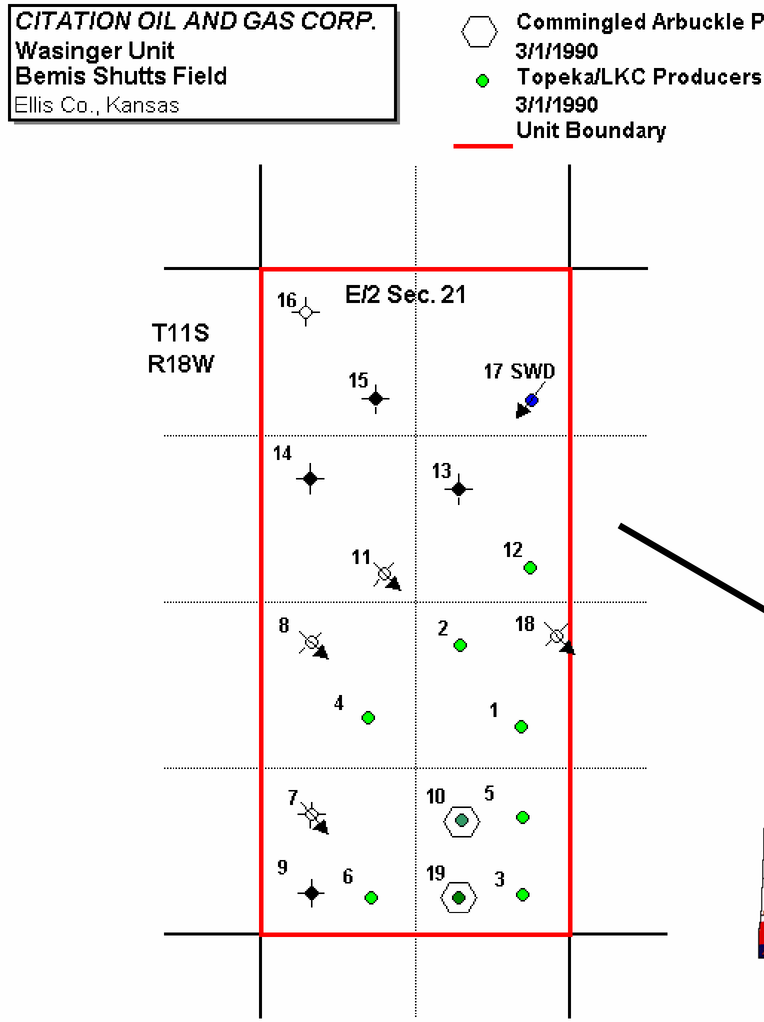


Typical Water Problem

With fractures or high perm connection to underlying aquifer

- Very high WOR wells
- Opportunity for greater draw-down
    - Increase oil from matrix
    - Downsize equipment
    - Reduce water handling costs
- Stimulation after treatment

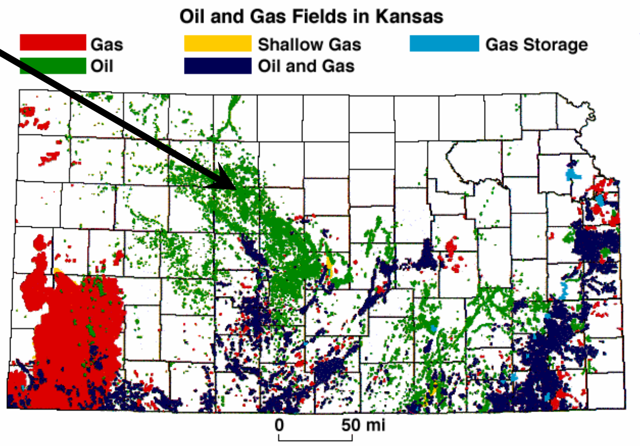




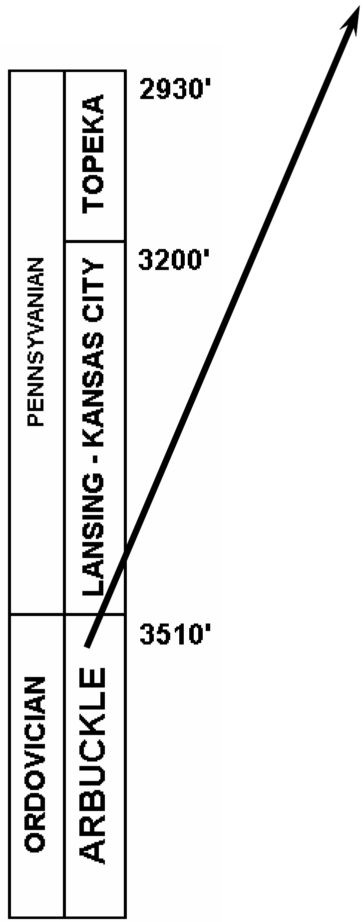
Discovered in 1948. Citation purchased in October, 1987.
In early 1990, 2 wells produced from the Arbuckle. 7 wells produced from the Topeka/LKC section.

Lease Prod.: 59 BOPD 5899 BWPD
Oil Cut 0.99%

Arbuckle: 35 BOPD 5709 BWPD
Top/LKC: 24 BOPD 190 BWPD



Citation Oil & Gas Corp.



TARGET FORMATION - ARBUCKLE
ORDOVICIAN DOLOMITE - 100 -200' THICK

Description in Cores:

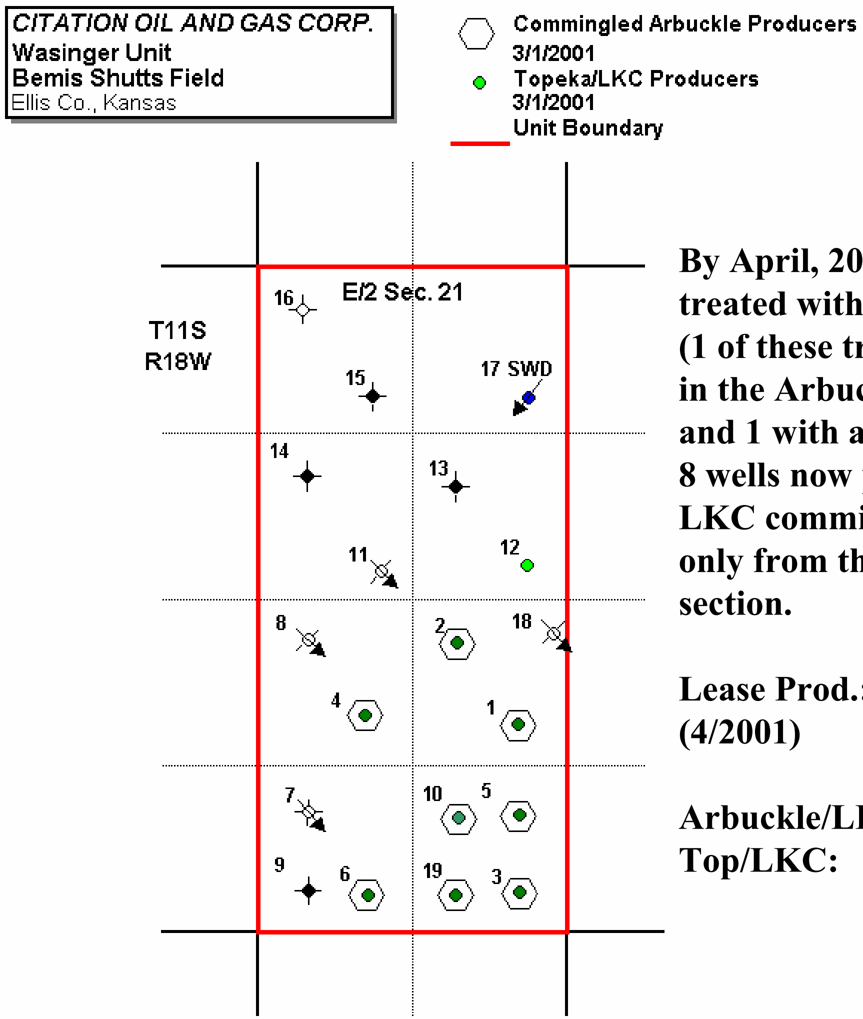
Sandy and crystalline dolomite with chert. Some shale streaks. No fractures described in cores or while drilling. Vugular porosity.

Productive Structure on Lease:

Subsea tops from -1523 to -1511'
Effective Oil/Water Contact (Cores) -1545'
Produces under a strong waterdrive.
Completions: Open Hole in top 4' to 6'

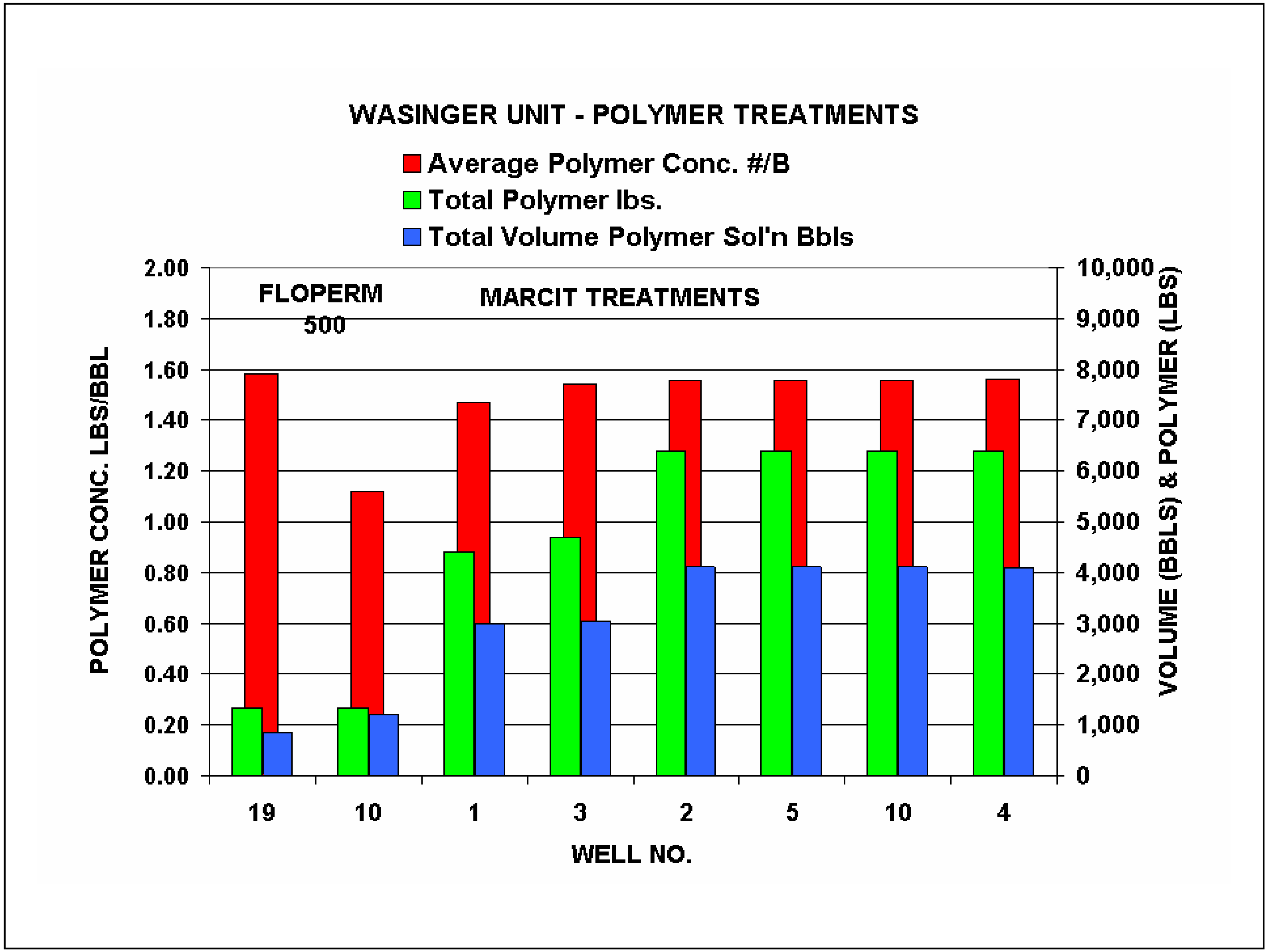
Characteristics:

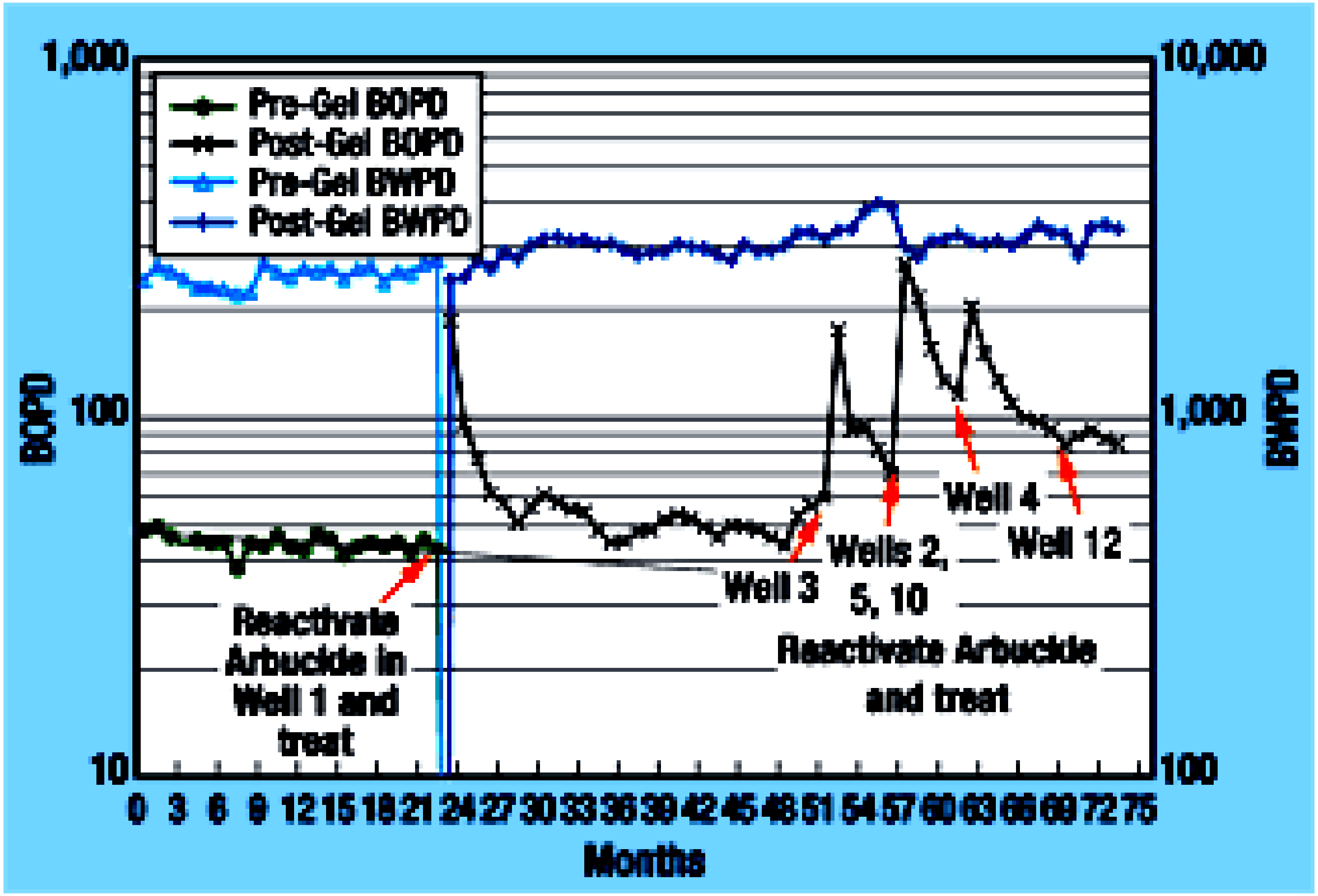
Porosity	9.5 to 20%
Permeability	20 to 500 md
Oil Gravity	27 Deg. API
Solution GOR	175 cf/STB
Initial Pressure	1020 psig
Temperature	112 Deg. F.

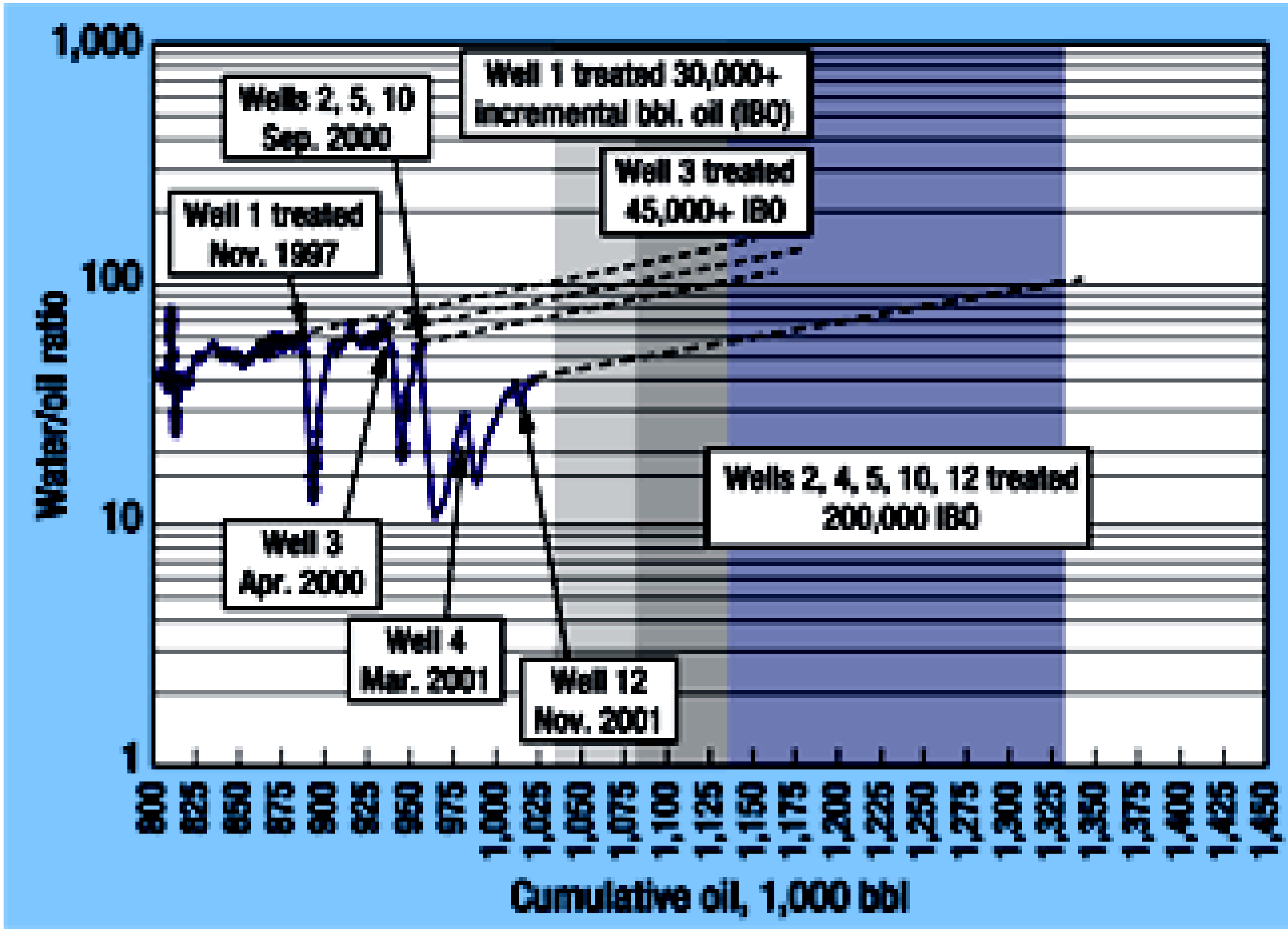


By April, 2001, 2 wells had been treated with polymer in the Arbuckle, (1 of these treated twice), 5 wells reactivated in the Arbuckle and treated with polymer and 1 with a cement/polymer treatment. 8 wells now produce from the Arbuckle/ LKC commingled and 1 well produces only from the Topeka/LKC section.

Lease Prod.: (4/2001)	**153 BOPD 3055 BWPD Oil Cut 4.8%**
Arbuckle/LKC:	**150 BOPD 3018 BWPD**
Top/LKC:	**3 BOPD 37 BWPD**


WASINGER UNIT - POLYMER TREATMENTS
Average Polymer Conc. #/B
Total Polymer lbs.
Total Volume Polymer Sol'n Bbls
FLOPERM 500
MARCIT TREATMENTS
POLYMER CONC. LBS/BBL
VOLUME (BBLS) & POLYMER (LBS)
2.00
1.80
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
19
10
1
3
2
5
10
4
WELL NO.


1,000
100
10
10,000
1,000
100
BOPD
BWPD
Pre-Gel BOPD
Post-Gel BOPD
Pre-Gel BWPD
Post-Gel BWPD
Reactivate Arbuckle in Well 1 and treat
Well 3
Wells 2, 5, 10
Well 4
Well 12
Reactivate Arbuckle and treat
0 3 6 9 12 15 18 21 24 27 30 33 36 39 42 45 48 51 54 57 60 63 66 69 72 75
Months


1,000
100
10
1
Water/oil ratio
Wells 2, 5, 10
Sep. 2000
Well 1 treated 30,000+
incremental bbl. oil (IBO)
Well 3 treated
45,000+ IBO
Well 1 treated
Nov. 1997
Wells 2, 4, 5, 10, 12 treated
200,000 IBO
Well 3
Apr. 2000
Well 4
Mar. 2001
Well 12
Nov. 2001
800
825
850
875
900
925
950
975
1,000
1,025
1,050
1,075
1,100
1,125
1,150
1,175
1,200
1,225
1,250
1,275
1,300
1,325
1,350
1,375
1,400
1,425
1,450
Cumulative oil, 1,000 bbl

Citation Oil & Gas Corp.

RESERVES DEVELOPED AND ESTIMATED COST

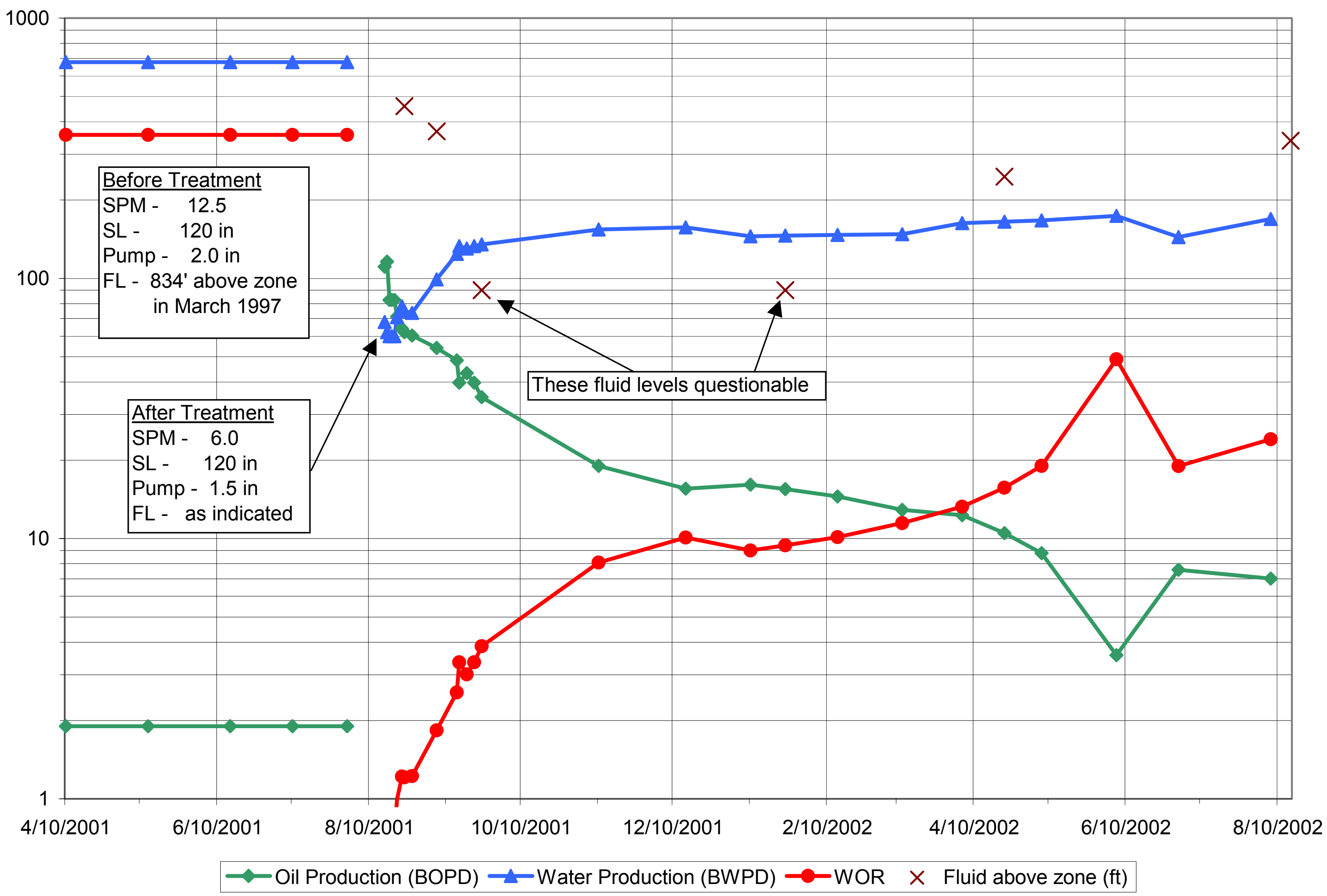
Estimated Reserves 4/1/1990 (Prior to Treatments)	119.7 MBO
Cumulative Production 4/1/90 - 4/30/01	245.0 MBO
Reserves Estimated at 4/1/01 with Treatments	283.5 MBO
Reserves at 4/1/1990 with Treatments	528.5 MBO
Change in Reserves	408.8 MBO
Estimated Costs of Treatments, Reactivations and Changes in Artificial Lift	940 M$
Cost per Gross Bbl. Added Reserves	$2.30/BO

Citation OIL & GAS CORP.

POTENTIAL SAVINGS IN WATER HANDLING:

Cumulative Oil Production from 4/1/90 - 4/30/01	245.0 MBO
Cumulative Water Production 4/1/90 - 4/30/01	12,498 MBW
Potential Water Production if Oil Cut had stayed at 1.0% as at April, 1990	24,255 MBW
Potential Decrease in Water Production 4/1/90 - 4/30/01	11,757 MBW
Potential Savings in Water Handling ($0.12/BW)	1,411 M$

(1621 bbls gel, 97% of job treated on a vacuum, 51 psig max treating press)



Petroleum Technology Transfer Council

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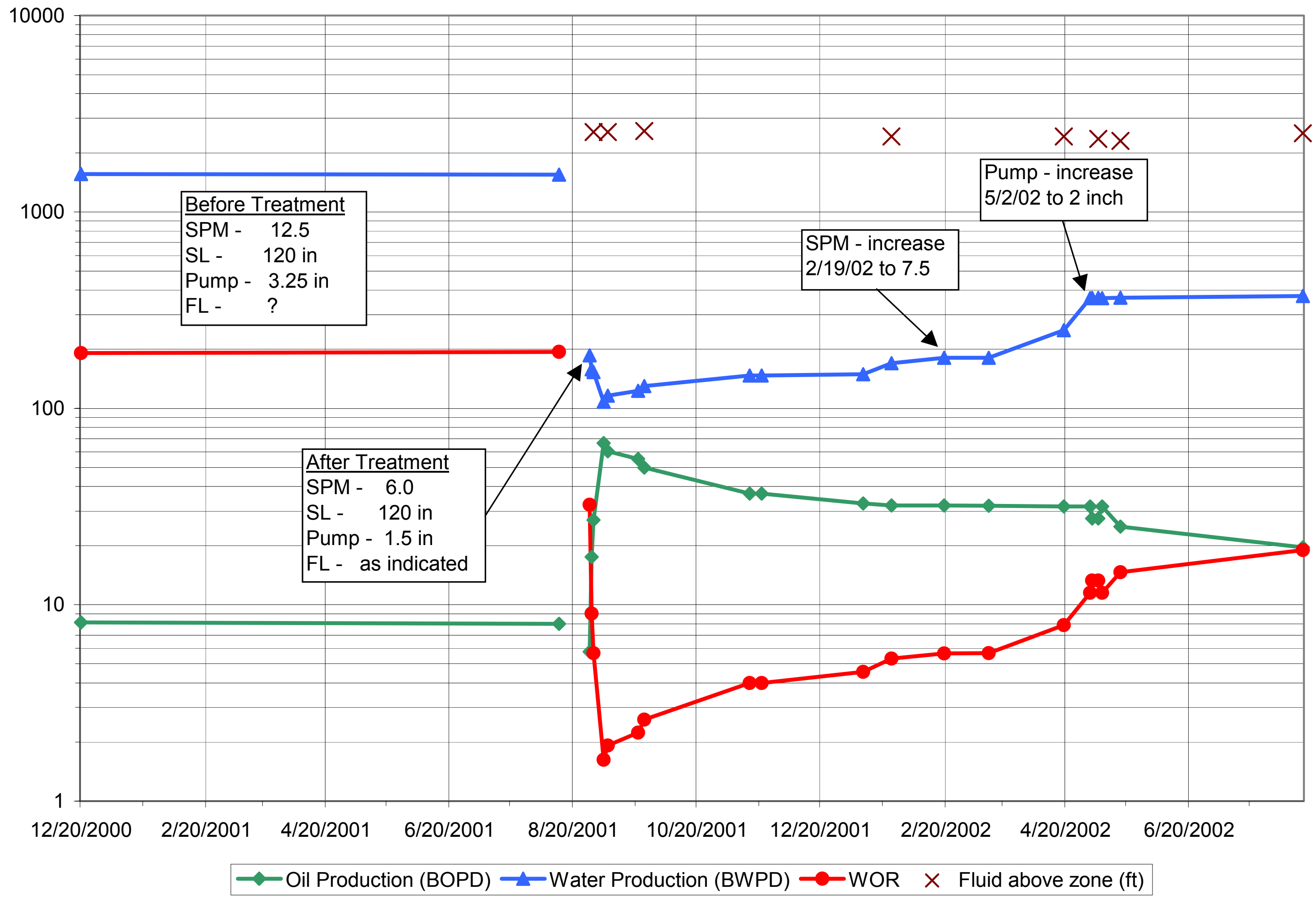
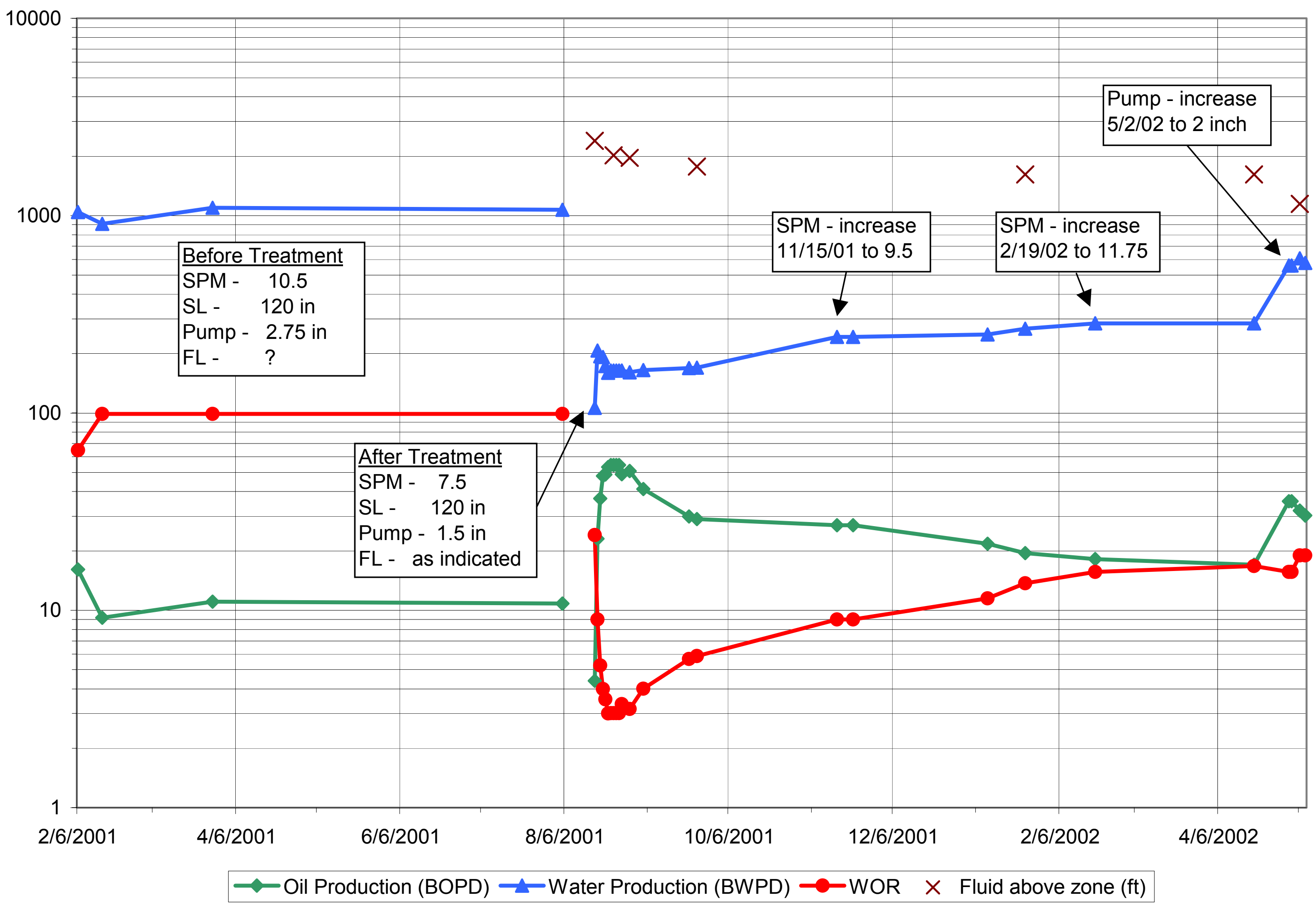
PTTC TECHNOLOGY CONNECTIONS

(3806 bbls gel, 100% of job treated on a vacuum, 0 psig max treating press)



(3805 bbls gel, 58% of job treated on a vacuum, 102 psig max treating press)



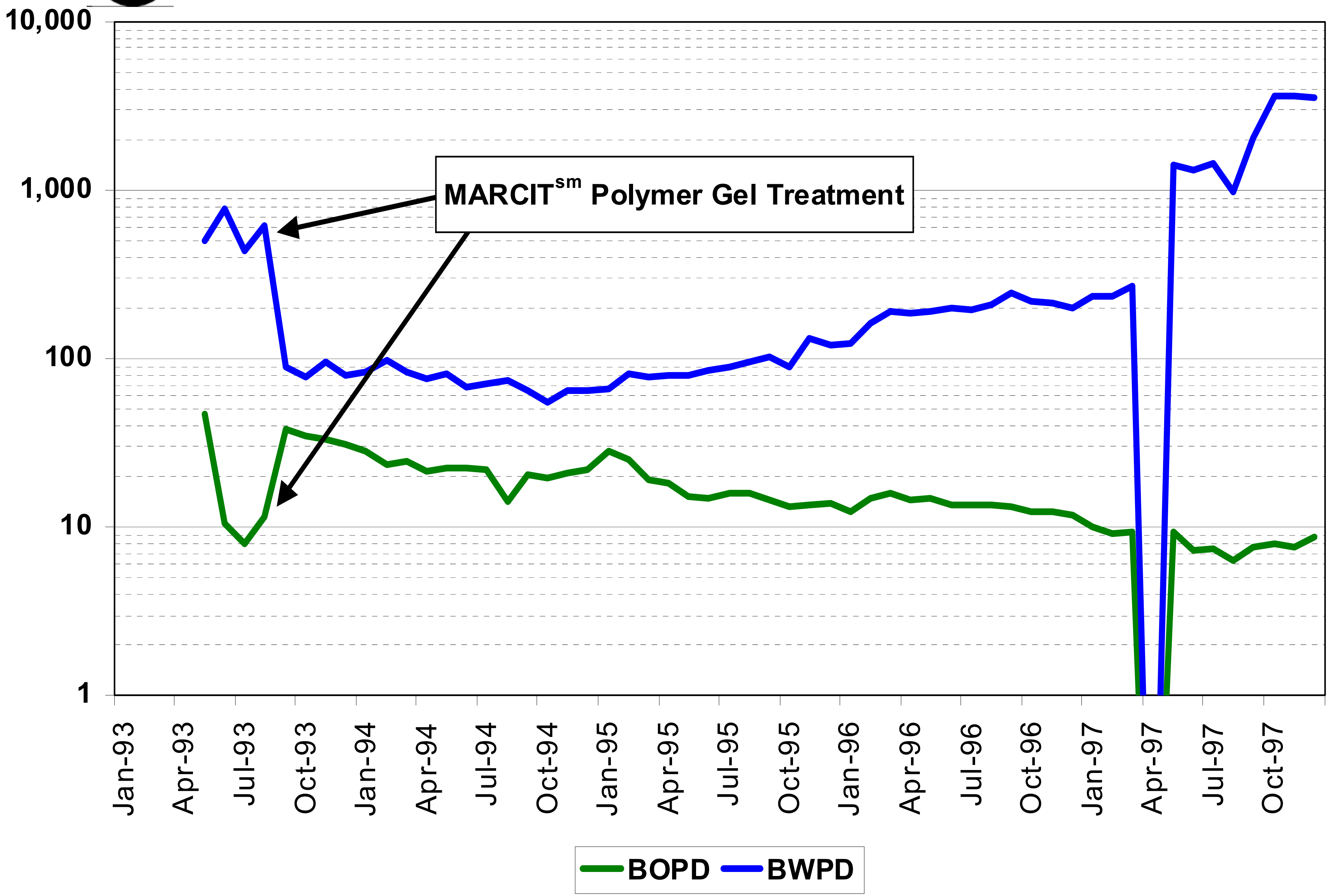
Hunton Dolomite Formation - Woods Co., OK
Background Information

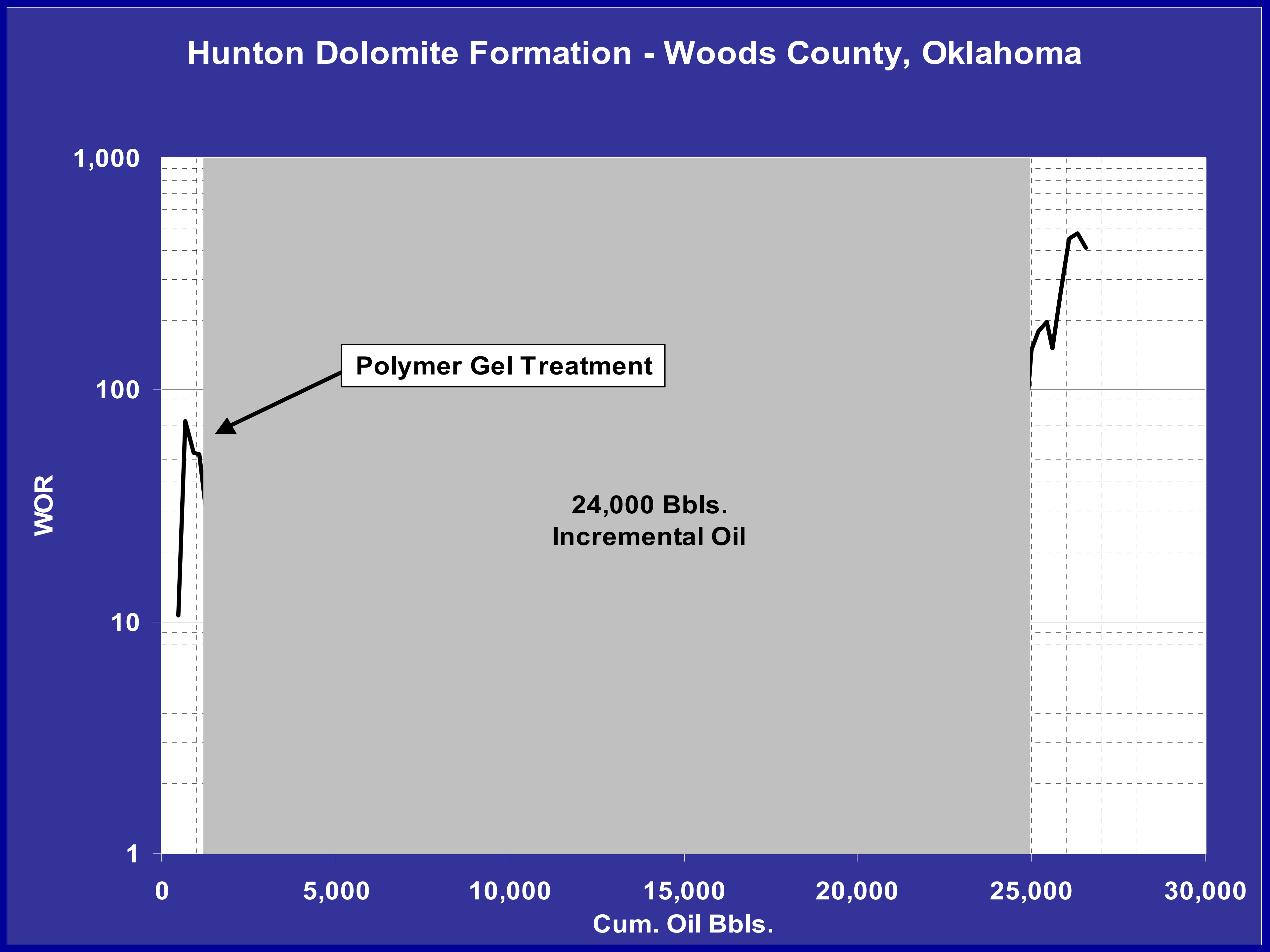
- Problem Description: Natural waterdrive reservoir. Excessive water production from vertical fractures connecting the wellbore to an underlying aquifer.
- Reservoir Depth: 6,200 ft.
- Perforated Interval: 6,190-6,194 ft. (4 ft.)
- Reservoir Temperature: 150° F
- Average Porosity: 7.6%
- Average Permeability: 127 md
- Oil Gravity: 36° API

Hunton Dolomite Formation - Woods Co., OK
Treatment Design & Job Specifics

- 990 Bbls. gelled polymer
- 3,000 - 6,000 ppm polymer
- 100 Bbl. water overflush
- 2 days to inject (0.35 bpm treating rate)
- Beginning Pressure: 0 psi
- Ending Pressure: 700 psi

Hunton Dolomite Formation - Woods County, Oklahoma




Hunton Dolomite Formation - Woods County, Oklahoma
1,000
100
10
1
WOR
Polymer Gel Treatment
24,000 Bbls.
Incremental Oil
0
5,000
10,000
15,000
20,000
25,000
30,000
Cum. Oil Bbls.

Hunton Dolomite Formation - Woods Co., OK
Treatment Economics

- **Time to payout: 45 days**
- **Incremental oil: 24,000 bbls.**
- **Job cost: $0.50 per incremental barrel of oil**

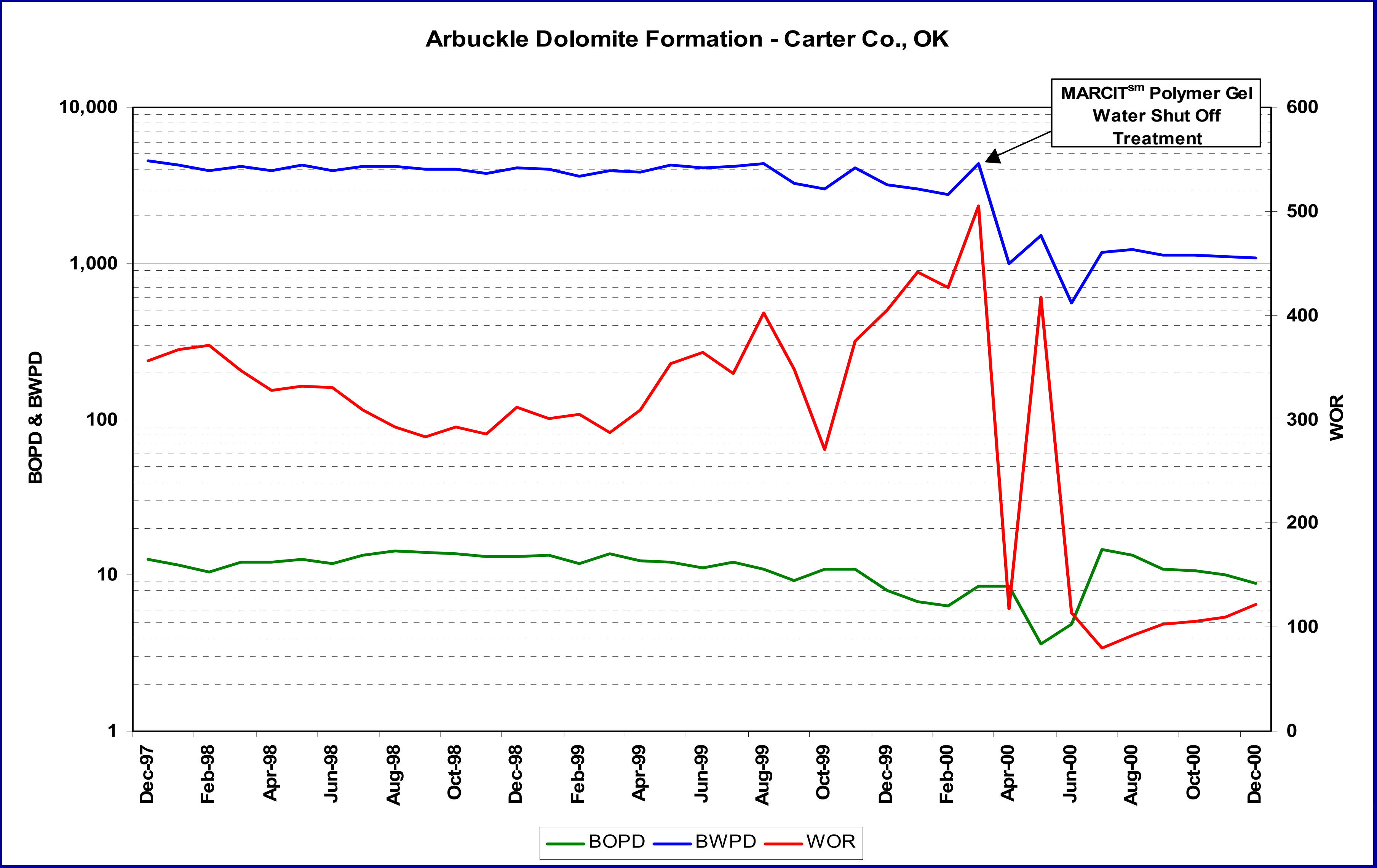
Arbuckle Dolomite Formation - Carter Co., OK
Background Information

- Problem Description: Natural waterdrive reservoir. Excessive water production from vertical fractures connecting the wellbore to an underlying aquifer.
- Reservoir Depth: 3,400 ft.
- Perforated Interval: 3,406-3,568 ft. (162 ft.)
- Reservoir Temperature: 99° F
- Average Porosity: 6%
- Average Permeability: 149 md
- Oil Gravity: 38° API

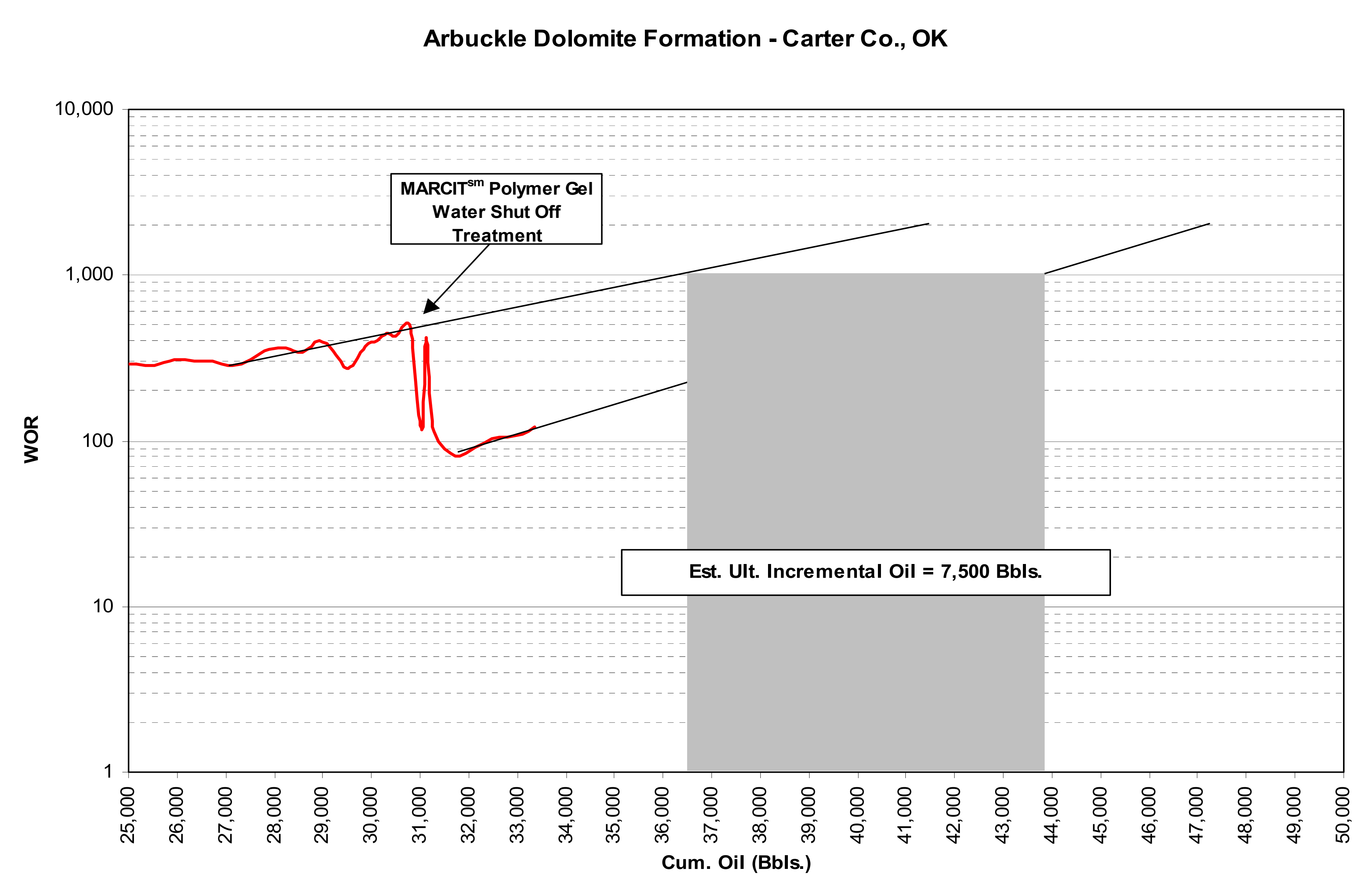
Arbuckle Dolomite Formation - Carter Co., OK
Treatment Design & Job Specifics

- 2,000 Bbls. gelled polymer
- 4,000 - 7,000 ppm polymer
- 86 Bbl. water overflush
- 2.5 days to inject (0.6 bpm treating rate)
- Beginning Pressure: 0 psi
- Ending Pressure: 185 psi

Arbuckle Dolomite Formation - Carter Co., OK
Rate vs. Time



Arbuckle Dolomite Formation - Carter Co., OK
Cum. Oil vs. WOR



Arbuckle Dolomite Formation - Carter Co., OK
Treatment Economics

- Time to payout: 6 months
- Estimated Ultimate Incremental oil: 7,500 bbls.
- Job cost: $2.53 per incremental barrel of oil