FILE : VIRDEN FIELD - GENERAL CORRESPONDENCE

CHEVRON CANADA RESOURCES
Eastern Business Unit, Virden Asset

POLYACRIMIDE GEL TREATMENT ECONOMIC EVALUATION

Prepared by: C. ULICKI

INTRODUCTION

A series of Marcit^{SM} polymer gel treatments were undertaken on 12 producing wells in 3 fields in the Virden area in 1993 and 1994. Two of these treatments were undertaken in the Roselea field and were unsuccessful at shutting off any water production, probably due to the presence of large fractures and a strong water drive (one of the wells was still flowing at 60 m3/day 100% water after pumping over 1000 bbls of gel). These wells are considered a technical failure and will not be discussed further in this paper. The three wells in Scallion and the seven wells in Routledge were technically successful when considered as a group; individual well responses varied. The economic value of these treatments will be examined in further detail.

Several months after the 1994 treatments, corrosion problems began appearing in or around the wells that had been treated with polymer gel, especially in the Scallion field. Test coupons that had shown little corrosion before the treatments were now showing excessive corrosion in a matter of weeks. Given that the watercut had decreased significantly in all the wells, this increase in corrosion created some confusion. However, as a series of rod breaks, tubing leaks, header leaks, and flowline leaks occurred, all in polymer wells, a connection between the polymer treatments and the increased corrosion was suspected. An examination of the wells treated in 1993 also showed increased corrosion, although not to the extent that any link between these occurrences and the polymer was evident.

Now that the polymer treatments had been identified as a possible cause of the corrosion, an investigation into the cause was undertaken by Chevron Canada Resources corrosion specialists, Baker Performance Chemicals alliance representatives, and Gel-Technologies Corporation (sales representative for the MARCIT^{SM} gel systems). It was determined that the polymer gel and the corrosion inhibitor (Cronox 338) were anionic and cationic, respectively. Thus, the differentially charged chemicals were attaching to each other and forming a spaghetti-like residue on the tubulars. This contributed to the corrosion in two ways; coating the tubulars so the inhibitor could not reach the metal, and consuming a large portion of the inhibitor in the reaction.

The question now remained as to how the polymer was being re-introduced into the wellbore. Gel-Technologies Corporation representatives assured us that it was unlikely that our pumping systems had enough drawdown to mobilize the gel in the reservoir, and suggested that the problem started when the tubulars were exposed to the polymer during the initial pumping of the gel. Yet on several occasions entire rod strings were replaced only to break due to corrosion the next month, evidence that the polymer was entering the well during normal production.

Two actions were taken to fix the corrosion problems caused by the polymer. First, the affected wells and associated flowlines in Scallion were treated with a bleach and surfactant solution. This solution was circulated through the tubulars for several hours at the rate of 50 litres per minute, allowing for a contact time of approximately one hour on any given section. This solution broke down and removed any residue created by the chemical reaction. The wells were then immediately treated with corrosion inhibitor and put back on production. Second, Baker Performance Chemicals used another inhibitor called Cronox P-30 that did not react with the polymer as severely. Additionally, treatment frequency had to be doubled to attain reasonable inhibition. Thus, all Scallion polymer wells and one Routledge well are now being treated with this chemical, and test coupons in Routledge are better than before the commencement of Cronox P-30. However, the coupons still show some deep corrosion along the edges, and are not as good as they were before the polymer squeezes. Since the bleach treatments and change of chemical two tubing leaks have occurred on one of the Scallion wells. Unfortunately, as the tubing string was not changed out at the time of the bleach job, it cannot be determined if this leak was the result of continuing corrosion, or if the tubing was already corroded before the bleach jobs began. This string has subsequently been replaced and no further leaks have occurred.

An economic analysis of the polymer project was undertaken in November 1994, before most of the corrosion problems began. The wells were examined in three groups: Scallion 1994 (three wells), Routledge 1993 (four wells), and Routledge 1994 (three wells). The analysis at that time showed that the polymer treatments in Scallion 1994 and Routledge 1993 added significant value to the wells, and that Routledge 1994 added marginal value. The following paper updates this analysis to include the cost of the corrosion problems, and takes into account revised production and price forecasts.

OPERATING COSTS

Operating costs include both fixed costs per well and variable costs per m^3 fluid. Operating costs generally increase by 3% per year. In the Scallion field a decrease in operating costs occurs in 1998 because one well would reach the economic limit and be abandoned. It is assumed that the water will return to pre-treatment levels by 1998 (approximately three years). A $10 000 increase in operating costs for the post-treatment scenario in Scallion is due to increased chemical costs needed to control the corrosion. In Routledge only one well is being treated with the new inhibitor, so incremental chemical costs are not large, and therefore not included.

Scallion 1994

Year	Without Polymer ($/year)	With Polymer ($/year)
1995	190000	59000
1996	197000	96000
1997	219000	157000
1998	132000	142000
1999	137000	147000
2000	143000	153000
2001	147000	157000
2002	151000	161000
2003	156000	166000
2004	160000	170000

Routledge 1993

Year	Without Polymer ($/year)	With Polymer ($/year)
1995	72700	46800
1996	55100	39100
1997	28500	35800
1998	29300	29300
1999	30200	30200

Routledge 1994

Year	Without Polymer ($/year)	With Polymer ($/year)
1995	50500	35900
1996	52800	41200
1997	55400	50300
1998	57900	57900
1999	60500	60500
2000	18200	18200
2001	18800	18800
2002	19300	19300

OTHER COSTS

Additional costs associated with the corrosion problems are shown below. Costs are classified as either tangible or intangible for taxation reasons.

Scallion 1994

	Tangible	Intangible
original job cost	72700	142300
6 rod breaks	0	18000
7 tubing leaks	0	28000
3 bleach jobs	0	21000
3 rod strings	12000	0
2 tubing strings	10000	0
2 header leaks	2300	2300
1 flowline leak	7800	3400
Total	104800	215000

Routledge 1993

	Tangible	Intangible
original job cost	5000	88000
3 rod breaks	0	9000
2 tubing leaks	0	8000
1 rod string	4000	0
Total	9000	105000

Routledge 1994

	Tangible	Intangible
original job cost	14400	93100

PRODUCTION FORECASTS

The production plots showing oil and water per day are attached in Appendix A. A decline analysis of the oil curves result in the numbers in the table below.

Scallion 1994

Year	Without Polymer (m3/year)	With Polymer (m3/year)
1995	3285	2860
1996	2920	2920
1997	2555	2555
1998	2190	2190
1999	1825	1825
2000	1460	1460
2001	1095	1095
2002	730	730
2003	365	365
2004	265	265
	incremental oil	-425

Routledge 1993

Year	Without Polymer (m3/year)	With Polymer (m3/year)
1995	2190	3285
1996	1460	2190
1997	1095	1460
1998	730	1095
1999	475	730
	incremental oil	2810

Routledge 1994

Year	Without Polymer (m3/year)	With Polymer (m3/year)
1995	2920	3285
1996	1825	1825
1997	1278	1278
1998	730	730
1999	438	438
2000	256	256
2001	146	146
	incremental oil	365

ECONOMIC INDICATORS

Chevron normally uses NPV_{12} as an economic indicator. However, the results are shown in the table below using the more common industry standard of NPV_{10}.

	NPV_{10} without polymer	NPV_{10} with polymer but not corrosion	NPV_{10} with polymer and corrosion	Incremental NPV_{10} without corrosion	Incremental NPV_{10} with corrosion
Scallion 1994	74000	189600	85100	115600	11100
Routledge 1993	177200	233600	218900	56400	41700
Routledge 1994	209700	184800	184800	-24900	-24900
Total				147 100	27900

CONCLUSIONS

The numerous corrosion problems experienced in Scallion drastically reduced the post-treatment value. Only marginal value was added ($11 000), even with the elimination of ESP equipment and an injection pump at a nearby battery and subsequent electricity and maintenance savings. The large incremental chemical costs over the remaining life of the wells affect the present value far more significantly than the initial equipment replacement and rig costs.

The revised economics for the Routledge 1993 program shows a greater than anticipated incremental value, largely because the increased oil production experienced after the polymer jobs has not fallen to pre-treatment levels. In fact, the post-treatment decline curve is the same slope as the pre-treatment curve, but approximately two m^3/day higher. These polymer treatments added about $40 000 value to the field, and saved a $150 000 battery upgrade, which was not directly included in the economics.

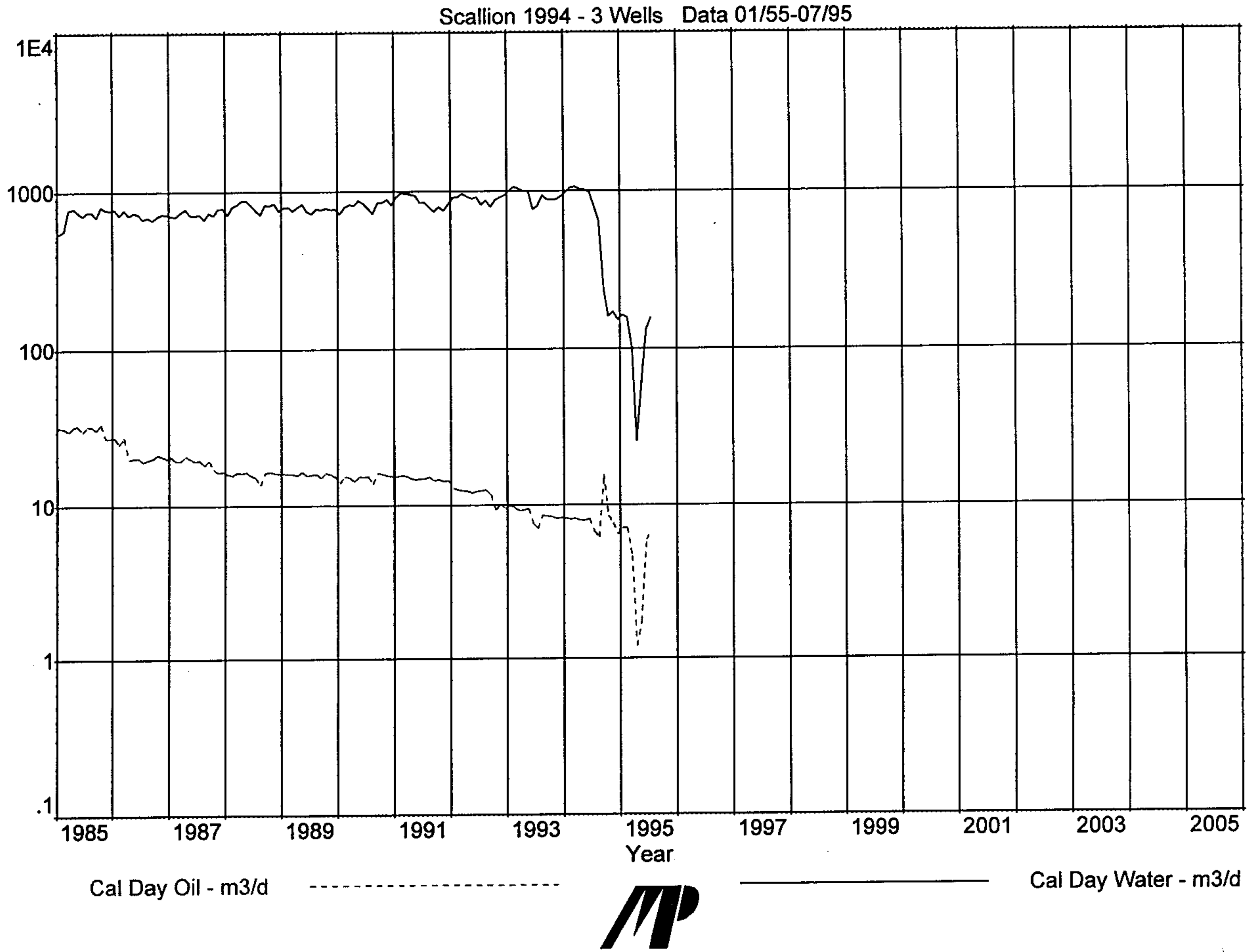
The production forecast used in the original analysis of the Routledge 1994 squeezes indicated higher than realized oil production due to a lack of post-treatment data. Therefore, using the most recent numbers results in a significantly lower value. These wells have not yet experienced any polymer related corrosion problems, but a lower than expected oil production means that the large expenditure for the treatments can not be recovered. The initial economics showed that this project was marginal at best, and the smaller than expected incremental oil the program in this field resulted in destroying about $25 000 of value.

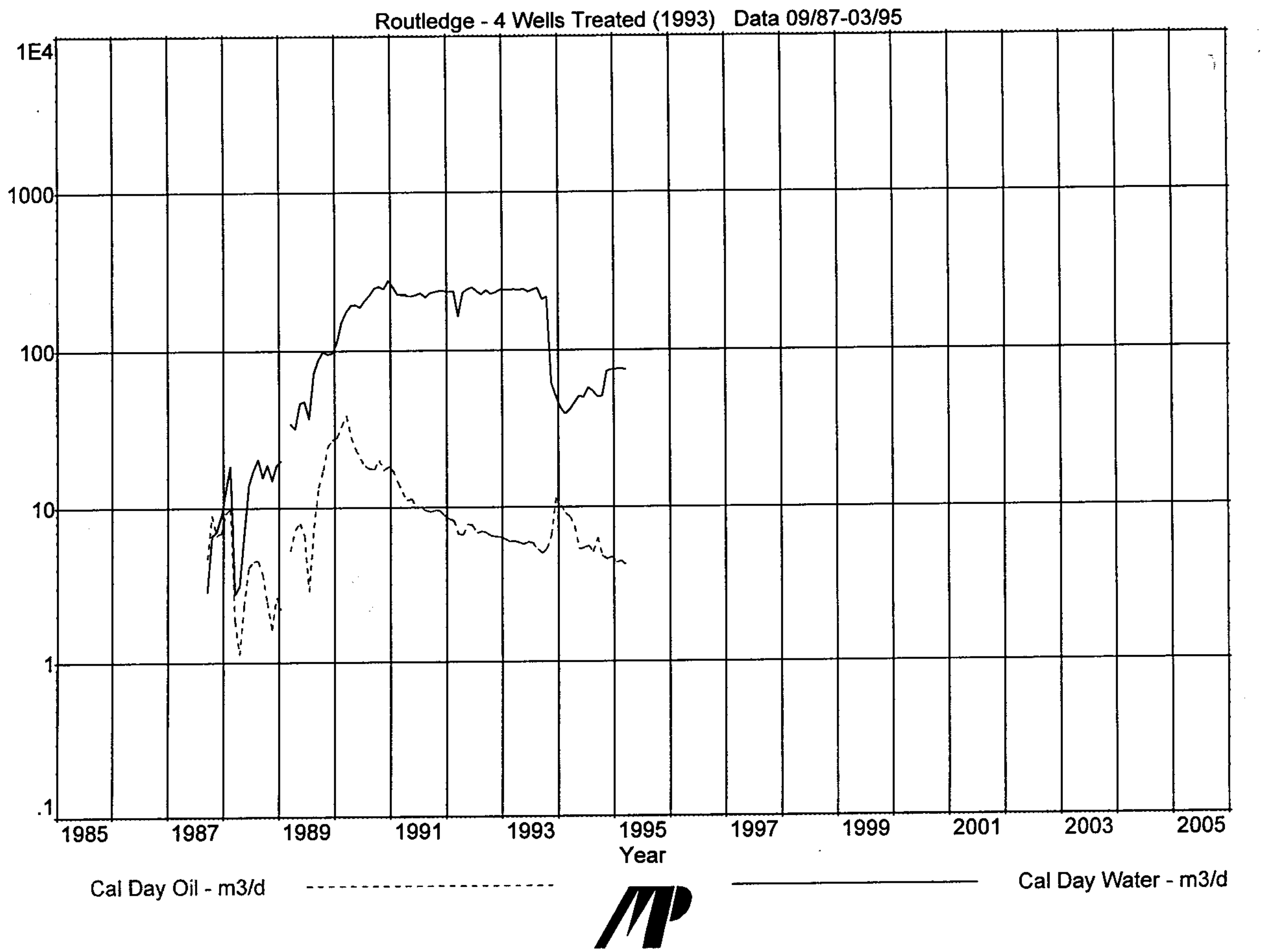
In general, the total program in all three fields increased value by approximately $28 000. Since the bleach treatments in Scallion, few corrosion problems have been experienced. However, it has only been a matter of months since the bleach was employed, and the problem may still occur again. Although the wells in Routledge were not bleached, the switch to the new inhibitor has shown positive results on the test coupons.

Polymer treatments on producing wells may still be a viable method of reducing operating costs. Although a solution to the corrosion problem has been found, it is still not known how to prevent the problem from occurring in the first place. Perhaps any future treatments should automatically be analyzed to include a bleach treatment, and proceed only if the results show that the treatment is still economic. However, the key point to adding value through polymer treatments is the careful selection of candidates. Using polymer with the primary intention of decreasing water production (as in the Routledge 1994 program) probably will not result in significant savings. However, using polymer to shut off water in conjunction with other considerations (preventing a battery upgrade or eliminating high cost equipment like ESPs and injection pumps) could add value to the field as a whole. Further monitoring of the corrosion situation should be undertaken over the next year. If no further problems occur, polymer may again be considered for use on producing wells in the Virden area.

APPENDIX A

Production Graphs


Scallion 1994 - 3 Wells   Data 01/55-07/95
1E4
1000
100
10
1
.1
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
Year
Cal Day Oil - m3/d
Cal Day Water - m3/d


Routledge - 4 Wells Treated (1993) Data 09/87-03/95
1E4
1000
100
10
1
.1
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
Year
Cal Day Oil - m3/d
Cal Day Water - m3/d

Routledge - 3 Wells Treated (1994) Data 03/88-03/95