PARAFFIN TREATMENT TECHNIQUES: A CASE STUDY

Gregory A. Hicks
Texaco USA

ABSTRACT

A study was initiated to establish a uniform method of removing paraffin from wells completed in the San Andres formation in Hockley and Cochran Counties, Texas. Several methods of paraffin removal, including hot-oiling, batch treating with chemical, paraffin inhibitor squeezes, and batch treating with paraffin-eating bacteria, were evaluated and the results reported.

Each year thousands of dollars are spent removing paraffin from tubing and flow lines in San Andres wells. The best methods for optimizing paraffin removal while minimizing lease expense will be discussed.

INTRODUCTION

The north and west sectors of the Levelland Area produce from the San Andres formation at an average depth of 5,000 feet. The north sector consists of the following leases: Montgomery Estate-Davies, Medarby, I. P. Deloache, Coble "A" and "B," Cunningham, Ham, Thruston, Whirley, and Wrenchy. The west sector consists of the C. S. Dean "A", XIT, and Southwest Levelland Units. Within these sectors are leases with Texaco working interests ranging from 28 to 100 percent. The two sectors combined produce 5,811 BOPD and 17,099 BWPD from 427 wells. The combined hot-oiling expense for 1988 was $233,148 or $546 per well. For this discussion hot-oiling will be defined as pumping hot water down the casing and hot oil down the flow line.

CRUDE OIL CHARACTERISTICS

Analysis of the crude showed an oil with a 24 to 30 degree API gravity containing 2 to 18 percent paraffin and 2 to 9 percent asphaltene residue as shown in Figure 1. The paraffin is a combination high molecular weight and branched microcrystalline wax as verified by gas chromatography analysis. The paraffin deposits analyzed contained a wax composed mainly of carbon number 40-50. The cloud point or temperature at which paraffin begins to precipitate ranged from 24 to 75 degrees Fahrenheit. The pour point or temperature at which the oil will not flow ranged from -55 to 5 degrees Fahrenheit. The melting point of the crude ranged from 160 to 168 degrees Fahrenheit.

METHODS EVALUATED

Several different types of paraffin removal were analyzed to determine the most effective and economical method of removing paraffin. The methods analyzed included hot-oiling, batch treating with chemical down the annulus, paraffin inhibitor squeezes, and batch treating with a paraffin-eating bacteria.

The north and west sectors had paraffin treating schedules in place at the time of this evaluation. These schedules were similar in type of fluids pumped but different in method of application. It was necessary to evaluate these different methods to develop a uniform paraffin treatment. First, different volumes were used on wells in the west sector and the results compared. Second, each lease's individual paraffin treating schedule was evaluated. Third, the recommended paraffin removal method was initiated on the XIT Unit and the results evaluated. Fourth, different chemicals were tested to determine the type and amount of hot-oiling chemical necessary to maximize paraffin removal.

INITIAL EVALUATION

Annular and flow-line volumes were varied for twelve wells on the C. S. Dean "A" and XIT Units and the results recorded. These results are tabulated in Figure 2. Three different types of treatments were analyzed in four well groups. The first included pumping 50 barrels of water down the casing and 10 barrels of oil per 1,000 feet of flow line. The second included pumping 75 barrels of water down the casing and 10 barrels of oil per 1,000 feet of flow line. The third consisted of pumping 75 barrels of water down the casing and 75 barrels of oil down the flow line. The motor's high and low amperage readings did not show a significant change between the three treatments. Flow-line pressures also showed little change between the three. Therefore, it was determined that the first type of treatment would be field tested on the XIT Unit.

FIELD TEST RESULTS

A field test was conducted on the XIT Unit with the recommended paraffin removal method. This method consisted of pumping 50 barrels of water mixed with 2.5 gallons of a non-ionic surfactant down the casing and pumping 10 barrels of oil per 1,000 feet of flow line. Wells on this lease were hot-oiled based on a schedule set for each individual well by the lease foreman. The wells were initially set up on a quarterly schedule. As the well was due for scheduled work, the check valves at the wellhead and satellite were visually inspected for paraffin deposition and compared to the wellhead pressure. If the inspection indicated that hot-oiling could be postponed, the treatment was delayed until the following month. The same procedure was repeated until it was deemed necessary to hot-oil. This procedure was repeated for each well until an optimum schedule was developed. Initiation of this paraffin removal method resulted in an average treating cost of $362 per well per year as shown in Figure 3. This was the lowest paraffin treating cost per well in the Levelland Area in 1988.

OTHER HOT-OILING METHODS

The west sector also utilized another type of paraffin removal on the C. S. Dean "A" and Southwest Levelland Units. These wells were hot-oiled with 75 barrels of water down the casing and 75 barrels of oil down the flow line. The water is also mixed with three gallons of a non-ionic surfactant. These two leases differ from any other leases evaluated in that most of the flow lines are either two- and three-inch steel and are on the surface. The wells drilled after 1976 are the only wells producing through buried fiberglass lines. This causes problems due to the size of the flow line and effects of cold weather. The Dean "A" and Southwest Levelland Units hot-oiling expenses for 1988 were $41,121 ($534/well) and $21,154 ($587/well), respectively. These numbers are tabulated in Figure 3. These are very low numbers considering the operating conditions.

The north sector utilizes a single method of paraffin removal. The majority of the wells on the lease are hot-oiled every quarter with 50 barrels of water down the annulus and 25 barrels of oil down the flow line as shown in Figure 2. Each load of fluid is mixed with five gallons of paraffin dispersant. Many of the wells are hot-oiled with 75 barrels of oil down the flow line in the second and fourth quarters as shown in Figure 4. This is to prepare the flow lines for winter in the fourth quarter and remove any buildup resulting from the cold winter months in the second quarter. This is not necessary in the west sector as lines are hot-oiled as needed as is shown in Figure 5. The north sector spends $135,688 on hot-oiling and hot-oiling chemicals per year. This equates to a cost of $625 per well per year as shown in Figure 3.

CHEMICAL EVALUATION

Chemical companies in the Levelland Area were requested to evaluate our paraffin and oil and submit their best product. These chemicals were tested with oil and paraffin from both the north and west sectors. Emulsion tendencies were also checked between the chemicals and the oils. The procedure for testing the chemicals is shown in Figure 6.

A non-ionic surfactant was selected as the chemical to be mixed in the water based on its ability to keep the cooled paraffin separated. A chemical to mix in the water was determined to be necessary to prevent any solids from being pumped into our formation. A surfactant is a good water-wetting chemical for formations. Many wells will go on a vacuum due to the low bottom-hole pressures encountered. A water-wetting chemical will benefit production over the life of the waterflood in this situation. Also this non-ionic surfactant is very good at carrying solids which will aid in removing iron sulfide and other plugging agents from the wellbore. The results of this test are shown in Figure 7.

Two chemicals were selected to mix with the oil when pumped down the flow lines or tubing. A paraffin solvent was selected to be used on the west sector while a paraffin dispersant was selected for the north sector. One gallon of each chemical was determined to adequate for any amount of oil pumped during hot-oiling. The test conducted on one gallon increments of these chemicals showed little increase in paraffin removal between one and five gallons. Using these chemicals will increase paraffin removal and decrease gunbarrel interface problems. The results of this test are shown in Figure 8.

After the chemicals were determined for hot-oiling, an emulsion tendency test was run. This consisted of obtaining three 100 cc samples and adding the appropriate amount of each chemical to each sample. The samples consisted of 25 percent, 50 percent, and 75 percent oil. An emulsion was not detected in any of the samples.

OTHER PARAFFIN REMOVAL METHODS

Other methods of paraffin removal were either tested or evaluated with little success. For a method to be tested, its treating cost had to be as a good as or better than the current treating cost. This eliminated the paraffin inhibitor squeezes and the paraffin-eating bacteria. The paraffin inhibitor squeezes had a recommended cost of $1,500 per well and had a forecast squeeze life of one year or less. The paraffin-eating bacteria had a recommended cost of $200 per well per month or a yearly cost of $2,400. These costs did not include any trucking or labor costs. These two methods were not tested as they did not meet economic criteria.

Batch treating with chemical down the annulus was tested with two different types of chemical. Two paraffin dispersants were tested on the XIT and Southwest Levelland Units. These chemicals were used in five of the problem wells on each lease. Treatments consisted of five gallons of chemical pumped down the annulus of each well and followed with five barrels of fresh water. Treatments were scheduled twice monthly at a cost of $30 per treatment or $60 per month. Two of the wells on each lease were pulled within two months after the project began to visually inspect for paraffin buildup on the rods. Paraffin was found no lower than 1,000 feet on the XIT and no lower than 1,200 feet on the Southwest Levelland. Paraffin accumulations were slight on the XIT and very heavy on the Southwest Levelland. All of these wells were discontinued as they had to be hot-oiled within six months of project initiation. Forecast cost for this type of treatment was $720 per year which is 24 percent greater than the current average hot-oiling cost.

RECOMMENDATIONS FOR INSTALLATION

A uniform paraffin removal method was developed after all methods had been evaluated. The following hot-oiling procedure was recommended:

1. Treat each producer with 50 barrels of fresh water down the annulus and ten barrels of oil per 1,000 feet of flow line. Temperature of all fluids will be 220 degrees Fahrenheit. Two gallons of a non-ionic surfactant will be added to the water while one gallon of either a paraffin solvent or paraffin dispersant will be added to the oil.

2. Monitor paraffin accumulation in the check valves at the wellhead and satellites/batteries and monitor flow-line pressures.

3. Adjust or establish hot-oiling schedules for each well.

4. Make hot-oiling schedules available to all field personnel.

5. Post schedules and update as work is done.

6. Update and evaluate hot-oiling schedules annually.

Installing the hot-oiling procedure as recommended will reduce expenditures and eliminate duplication of work.

DISCUSSION

The number of times a well will require hot-oiling is dependent on two factors. These are the cloud point and pour point of the oil the well is producing and the location, length, and pressure of the flow line the oil is moving through. The cloud point and pour point are not controllable and must be monitored through chemical companies. The flow lines can be monitored and controlled. Flow-line location, length, and pressure are key factors in determining when a well should be hot-oiled. The capacity of a three-inch line is 8.75 barrels per 1,000 feet. This means 25 barrels of oil is fine for a line 2,500 feet long. A line 5,000 feet long will require 44 barrels of oil to completely heat the entire line. Under the north sector's current procedure the 5,000-foot line will get 25 barrels of oil. This will heat only half of the line. This forces the foreman to come back to the well to hot-oil the flow line only before and after winter due to the buildup in the flow line. By using the recommended procedure, the return trip to the well would be eliminated, thus reducing expenses. With the flow lines being buried on the north sector, the rapid changes in surface temperature will have little effect on the oil. It will be necessary to install a flow-line valve on each well if the wellhead accumulation is to be monitored. Monitoring the flow-line pressures and wellhead accumulations will be the key to initiating this project on the north sector.

The west sector will need to reduce the amount of fluid pumped down both the casing and flow line. The average well on the west sector produces an average of 50 barrels of fluid per day. Pumping 75 barrels only increases the time until the well returns to its original production. Two-inch flow lines on the surface increases the foremen's operational problems. The capacity of a two-inch flow line is 3.9 barrels per 1,000 feet. Using the recommended 10 barrels per 1,000 feet will more than double the volume of the flow line. The problem with the Dean "A" Lease is that some wellhead pressures are difficult to monitor due to back pressure valves installed on the flow line. This increases the need to pull check valves at the wellhead and satellite to monitor paraffin accumulation. The Southwest Levelland Unit is in the same condition as the Dean "A." The west sector has also been experiencing an increase in paraffin accumulation since the installation of gunbarrels on the Dean "A" and XIT Units. Adding a paraffin solvent to the oil pumped down the flow lines will increase the paraffin removal from the system. In the past, paraffin solvent has not been added to the oil, allowing the paraffin to precipitate after it was removed from the flow lines. This causes operational problems such as thick interfaces in the gunbarrels. Reducing gunbarrel problems will allow the pumper and foreman to have more time for other tasks.

ECONOMICS

Both sectors currently have good hot-oiling programs. However, with a small adjustment to the recommended procedure, the area's hot-oiling expenses will be reduced by $26,163 (11.2 percent). This reduction is based on hot-oiling each well on the north and west sector an average of four and three times per year, respectively. The north sector will reduce hot-oiling by $7,498 and chemical usage by $10,202. The west sector will reduce hot-oiling by $10,544 but will increase chemical usage by $2,081. The increase in chemical is a result of the west sector's not adding chemical to the oil in the past. The savings in hot-oiling is a minimum that will be realized. As each well's schedule is established, the savings will be even greater. These calculations are shown in Figure 9.

CONCLUSIONS

Initiation of a uniform hot-oiling program will help maximize lease profit, minimize paraffin problems, and reduce duplication of work. Establishing hot-oiling schedules will promote communication between foremen and field personnel and maximize the efficiency of field operations.

OIL COMPOSTION

LEVELLAND NORTH AND WEST SUB-AREAS

LEVELLAND NORTH SUB-AREA LEASE AND WELL NO.	DATE DRILLED	BOPD	BWPD	MCFPD	API GRAVITY	CLOUD POINT	POUR POINT	PER-CENT PARAFFIN	PER-CENT ASPHALTENE
I. P. Deloache #9	9-15-80	79	2	42	29.0	24	-55	9.2	3.7
I. P. Deloache #12	10-31-81	29	3	15	29.8	36	-35	9.9	4.2
Montgomery Estate Davies NCT-2 #126	9-05-84	5	11	2	30.3	29	-50	3.3	1.6
Montgomery Estate Davies NCT-2 #127	9-22-84	28	1	11	30.3	33	5	8.6	2.6
LEVELLAND WEST SUB-AREA LEASE AND WELL NO.									
S.W.L.U. #2	4-02-51	28	6	9	29.9	65	-4	5.3	7.3
S.W.L.U. #48	7-13-49	5	38	2	24.2	75	5	5.5	2.8
S.W.L.U. #111	4-08-82	24	18	7	30.1	55	-25	5.7	6.3
XIT Unit #72	2-03-51	30	5	14	28.6	74	5	17.9	2.7
XIT Unit #164	5-05-78	8	2	4	26.4	68	2	15.1	4.9

Melting Point for all Crudes was 160-168°F

Figure 1

HOT OILING TEST
VARYING RATES
XIT AND C.S. DEAN "A" UNITS
LEVELLAND WEST SUB-AREA

LEASE AND WELL NO.	PRODUCTION OIL BPD	WATER BPD	GAS MCFPD	HOT OIL TREATMENT CSG	FL	FLOWLINE LENGTH TYPE	FLOWLINE TYPE MEASURMENT	BEFORE	AFTER	READINGS WEEKS AFTER TREATMENT: 1	2	4	6	10
XIT #87	18	17	7	50	25	741' 3" FG Buried	Amperage Hi/Lo Line Pressure	18/10 25	16/10 25	15/7 23	14/7 18	15/7 18	16/8 18	16/8 18
XIT #94	6	52	2	50	25	2562' 3" St. Buried	Amperage Hi/Lo Line Pressure	27/12 26	23/12 25	23/12 25	22/12 25	22/12 25	23/12 25	26/12 25
XIT #154	27	71	7	50	35	3244' 3" FG Buried	Amperage Hi/Lo Line Pressure	52/22 22	55/22 20	47/22 20	47/22 20	48/22 20	49/22 20	50/22 20
XIT #183	21	10	11	50	25	1396' 3" FG Buried	Amperage Hi/Lo Line Pressure	25/10 25	25/10 20	25/10 20	25/10 20	25/10 20	25/10 20	25/10 20
Dean A #129X	7	38	5	75	25	2000' 2" St. Surface	Amperage Hi/Lo Line pressure	37/13 95	34/13 95	37/15 95	34/13 95	35/13 95	34/13 95	35/13 95
Dean A #137	22	114	11	75	35	3400' 2" St. Surface	Amperage Hi/Lo Line Pressure	52/22 115	47/22 105	47/22 105	47/22 105	47/22 105	49/22 110	47/22 110
Dean A #158	15	30	6	75	25	1900' 2" St. Surface	Amerage Hi/Lo Line Pressure	40/34 80	37/14 80	37/14 80	37/14 80	37/14 80	38/14 80	39/14 80
Dean A #164	26	79	15	75	25	200' 2" St. Surface	Amerage Hi/Lo Line Pressure	35/17 85	33/15 80	31/15 80	31/15 80	31/15 80	31/15 80	33/15 80
XIT #187	11	29	4	75	75	4625' 3" FG Buried	Amperage Hi/Lo Line pressure	34/14 35	37/14 25	36/14 30	34/14 30	34/14 30	34/14 30	34/14 32
Dean A #24X	22	12	8	75	75	2100' 2" St. Surface	Amperage Hi/Lo Line Pressure	40/16 80	40/16 70	40/16 70	40/16 70	40/16 70	40/16 70	40/16 70
Dean A #140X	14	7	4	75	75	2700' 2" St. Surface	Amperage Hi/Lo Line pressure	47/17 95	43/17 90	43/17 90	43/17 90	45/17 90	45/17 95	45/17 95
Dean A #173	17	60	9	75	75	3400' 2" St. Surface	Amperage Hi/Lo Line Pressure	27/18 75	37/18 75	35/18 80	35/18 75	33/18 75	30/18 75	27/18 75

Figure 2

1988 HOT-OILING EXPENSE SUMMARY

NORTH AND WEST SECTORS

LEASE OR UNIT	NUMBER OF WELLS	NUMBER OF TREATMENTS	HOT-OILING VOLUME	HOT-OILING COST	CHEMICAL VOLUME	CHEMICAL COST	TOTAL HOT-OILING COST	YEARLY COST PER/WELL	NUMBER TREATMENTS PER/WELL	COST PER TREATMENT	CHEMICAL PER TREATMENT
C. S. Dean A	77	174	24,570	37,879	655	3,242	41,121	534	2.26	236	3.8
S.W.L.U.	36	93	13,370	20,560	120	594	21,154	587	2.58	227	1.3
XIT	97	185	19,641	31,318	692	3,867	35,185	362	1.91	180	3.7
WEST AREA	210	452	57,581	89,757	1,467	7,703	97,460	464	2.15	216	3.3
W.E.D.	111	424	36,735	57,524	2,335	13,987	71,511	644	3.82	168	5.5
Wedarby	35	128	10,205	16,302	580	3,534	19,836	566	3.65	155	4.5
Deloache	34	159	12,620	20,027	738	4,420	24,447	719	4.68	154	4.6
Coble A & Others	37	139	11,340	17,840	343	2,054	19,894	537	3.76	143	2.5
NORTH AREA	217	850	70,900	111,693	3,996	23,995	135,688	625	3.92	159	4.7

Figure 3

HOT OIL TREATMENTS

Sub-Area: West

Casing and Flowlines
Quarter Totals

LEASE	NO. OF PRODUCERS	% OIL CUT	FIRST	SECOND	THIRD	FOURTH	YEARLY TOTAL
********	*********	*****	*****	******	*****	******	*******
Dean A	77	21	38	42	48	35	163
S.W.L.U.	36	21	5	40	25	21	91
XIT	97	28	48	43	50	37	178
West TTL	210	24	91	125	123	93	432

Sub-Area: West

Flowline Only
Quarter Totals

LEASE	NO. OF PRODUCERS	% OIL CUT	FIRST	SECOND	THIRD	FOURTH	YEARLY TOTAL
********	*********	*****	*****	******	*****	******	*******
Dean A	77	21	9	0	1	1	11
S.W.L.U.	36	21	1	0	1	0	2
XIT	97	28	4	0	3	0	7
West TTL	210	24	14	0	5	1	20

Figure 4

HOT OIL TREATMENTS

Sub-Area: North

Casing and Flowlines
Quarter Totals

LEASE	NO. OF PRODUCERS	% OIL CUT	FIRST	SECOND	THIRD	FOURTH	YEARLY TOTAL
********	*********	*****	*****	******	*****	******	*******
MED NCT-2	111	35	94	77	82	95	348
Medarby	35	11	26	25	24	23	98
Deloache	34	45	35	19	41	21	116
Other	37	28	23	37	37	30	127
North TTL	217	27	178	158	184	169	689

Sub-Area: North

Flowline Only
Quarter Totals

LEASE	NO. OF PRODUCERS	% OIL CUT	FIRST	SECOND	THIRD	FOURTH	YEARLY TOTAL
********	*********	*****	*****	******	*****	******	*******
MED NCT-2	111	35	5	26	0	45	76
Medarby	35	11	5	12	3	10	30
Deloache	34	45	1	21	2	19	43
Other	37	28	3	3	3	3	12
North TTL	217	27	14	62	8	77	161

NOTE: The Other catagory contains small leases such as the W. T. Coble A & B, and small 3 and 4 well leases.

Figure 5

Hot-Watering Chemical Test
North and West Sector
Methods of Testing

Hot-Watering Chemical

1) Gather sample of fresh paraffin from rods and flowline.
2) Smear paraffin on inside of wide mouth beaker.
3) Fill beaker with 200 cc of tap water.
4) Add 0.19 cc of chemical to beaker.
5) Heat beaker to 220 degrees farenheit and visually inspect.
6) Drop magnetic stir rod into beaker. Stir at low speed and visually inspect.
7) Remove beaker from heat and place in room temperature water bath.
8) Repeat for each chemical and record all results.

Hot-Oiling Chemical

1) Weigh beaker. Smear paraffin on bottom and sides of beaker. Reweigh beaker.
2) Pour 50 cc of oil in beaker. Add 0.02 cc of chemical. Heat to 220 degrees farenheit and visually inspect.
3) Remove from heat and place in room temperature bath. Visually inspect. Let cool to 75 degrees farenheit and pour out excess oil. Reweigh beaker.
4) Repeat for each chemical and record all results.

Figure 6

Hot-Watering Chemical Test

North and West Sectors

Chemical	Results of Melted Paraffin Inspection
Company A Chem 1	No large chunks of paraffin. Smooth oil on top.
Company A Chem 2	No large chunks of paraffin. Some small chunks remained.
Company B Chem 1	Not water soluble. Small chunks remained.
Company C Chem 1	Good dispersion of oil.
Company D Chem 1	Dispersed paraffin before water heated to 190 degrees fahrenheit.

Chemical	Results of Stirring Fluid
Company A Chem 1	Began sticking to glass when stirred.
Company A Chem 2	Began sticking to glass when stirred.
Company B Chem 1	Thick clump of paraffin caused very little sticking to glass.
Company C Chem 1	Good dispersion of large clumps. Very little sticking to glass.
Company D Chem 1	Paraffin did not stick to glass. Kept paraffin in small dispersed chunks.

Chemical	Results of Cooling
Company A Chem 1	At 148 degrees fahrenheit, smaller chunks began sticking together.
Company A Chem 2	Chunks began sticking together at 140 degrees fahrenheit.
Company B Chem 1	Chunks began sticking to glass at 150 degrees fahrenheit.
Company C Chem 1	Began sticking to glass at 140 degrees fahrenheit. Still had small chunks exhibiting good surface tension reduction at 125 degrees fahrenheit.
Company D Chem 1	Some sticking to glass. Chunks would not stick together at 120 degrees fahrenheit. Exhibited good surface tension reduction.

Figure 7

Hot-Oiling Chemical Test

North and West Sectors

Chemical	Cost per Gal.	Initial Paraffin Weight Grams	Paraffin Removed Grams	Comments
Company A PD	8.45	2.5	1.3	Thin paraffin-type residue remained.
Company C PD	7.91	2.5	2.0	Crystal residue left in beaker.
Company C PD	5.99	2.5	2.1	Very litte residue left in beaker.
Company B PS	5.63	2.5	2.1	Very little residue left in beaker.
Company D PS	5.95	2.5	1.6	Paraffin-type residue left in beaker.
Company D PS	5.95	2.5	1.6	Small crystal residue left in beaker.
Blank No Chemical		2.5	0.9	Paraffin and crystals remained in beaker.

Chemical	Vol Gals	Initial Paraffin Grams	Paraffin Removed Grams	Comments
Paraffin Solvent	1	4.0	2.7	Good paraffin removal.
	2	4.0	2.2	Large crystals remained.
	3	4.0	2.1	Large crystals remained.
	4	4.0	2.5	Good paraffin removal.
	5	4.0	2.8	Good paraffin removal.
	Blank	4.0	1.7	Paraffin and crystals remained.

Figure 8

Hot-Oiling Expense Reduction
North and West Sectors

North Sector

Hot-Oiling Savings

1988 Hot-Oiling Cost	$ 111,694
Estimated Yearly Hot-Oiling Cost	104,196
Yearly Hot-Oiling Savings	$ 7,498

Estimated yearly hot-oiling savings was based on the current quarterly hot-oiling schedule but with different volumes.

Chemical Savings

Cost per treatment:
(2 gals. NIS x $4.95) + (1 gal. PD x $5.99) = $15.89
Total Yearly Cost:
4 treatments/well x 217 wells x $15.89/treatment = $13,793
Current Chemical Costs: $23,995
Total Chemical Savings = $23,995 - 13,793 = $10,202

Total North Sector Savings = $7,498 + $10,202 = $ 17,700

West Sector

Hot-Oiling Savings

1988 Hot-Oiling Cost	$ 89,757
Estimated Yearly Hot-Oiling Cost	79,213
Yearly Hot-Oiling Savings	$ 10,544

Estimated yearly hot-oiling cost based on an average of three treatments per well per year.

Chemical Savings

Cost per treatment:
(2 gals. NIS x $4.95) + (1 gal. PS x $5.63) = $15.53
Total Yearly Cost:
3 treatments/well x 210 wells x $15.53/treatment = $9,784
Current Chemical Cost: $7,703
Increase in Chemical Expense = $9,784 - 7,703 = $2,081

Total West Sector Savings = $10,544 - $2,081 = $8,463

Total North and West Sector Savings = $17,700 + $8,463 = $26,163

Reduction in Expenses: $26,163/$233,148 = 11.2%

Figure 9