

# Prolonged Experience Processing High Acid Crude

## Cross Oil & Refining Company

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### Abstract

Cross Oil operates a specialties hydrocarbon product extraction plant. Charge to the extraction plant is typically 20 API gravity crude with a TAN value of approximately 2.0 mg/gm. The refinery processed these high-acid crudes on a continuing basis since 1993 and evaluated a number of different suppliers and several different technologies to mitigate the corrosion potential of these high-acid crudes. Applying technologies like caustic and phosphate ester corrosion inhibitors were effective in controlling the naphthenic acid corrosion but resulted in fouling in the Crude, Vacuum, and Hydrotreater units. Application of the phosphate esters also resulted in Hydrotreater catalyst deactivation. This paper discusses the application of a sulphur-based corrosion inhibitor, which was applied to the refinery crude unit to eliminate the fouling seen with caustic and phosphate esters and still maintain adequate high temperature naphthenic acid corrosion control

### Cross Oil & Refining

Cross Oil & Refining Company is a quality supplier of naphthenic acid lubricating oils used in specialty applications and processes since 1930. Products include specialty base and process oils, electrical insulating oil, roofing asphalt, a full range of high quality military specification greases, lubricants, and metal working fluids. These products are used in diverse downstream applications such as blender

compounds, chemical intermediate, rubber extenders, inks, explosives, solvents, tires, and carpet fiber. In addition to producing the specialty products, the refinery also produces a full range of traditional petroleum based refined products such as naphtha, kerosene, and diesel fuels.

The refinery purchases a standardized and controlled blend of select naphthenic acid crudes and maintains uniform operating conditions so that the refinery can produce the consistent high quality products required by their customers. This tightly controlled scenario has provided a stable and consistent platform for comparing the efficacy of the treatment programs used over the last 10 years.

The refinery processes 7,000 bbl per day of naphthenic acid crudes through atmospheric and vacuum distillation. After the distillation, the various blended component feedstocks are further severely hydrotreated in a Hydro Desulphurization Unit to remove sulphur compounds, color bodies, unsaturated olefins, and acids and to produce the final blended sales products.

### Crude and Vacuum Units Metallurgy

The refinery metallurgy is mostly carbon steel with the exception of the following components, which were upgraded to 317 Stainless Steel:

- > Atmospheric Heater transfer line to atmospheric column replaced in 1999
- > Atmospheric column Flash Zone clad in 1999



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- > Piping from Atmospheric column to Vacuum Heater replaced in 2001
- > Vacuum Heater transfer line to vacuum column replaced in 2001
- > Vacuum column flash zone to 9 stream draw tray clad in 2001

Since most of the systems are carbon steel, the challenge of corrosion control of high acid crudes is more difficult and challenging.

## Processing History of Naphthenic Acid Crude

The history of chemical treatment of high-acid crude processing can be divided into four distinct and separate periods.

1. The first period, which started in mid-1993 and ended in mid-1998, involved caustic addition.
2. The second period included caustic addition enhanced by the injection of various phosphate ester based chemistries.
3. The third phase involved the removal of caustic and the addition of a combined sulphur and phosphate ester.
4. The fourth period, and the one still being used, is a GE Infrastructure Water & Process Technologies sulphur-based corrosion inhibitor. All four periods will be discussed briefly with the focus of the discussion on the improvements gained from the GE sulphur-based corrosion inhibitor over the combined sulphur phosphate ester program.

Prior to mid-1993, because the refinery purchased and charged crudes that had a whole crude TAN value of less than 0.5 mg/gm TAN, high temperature naphthenic acid corrosion was not a factor or concern. In 1993 it was recognized that there were crude sources available which would provide a significantly improved product yield structure over the normal crude slate. However, these crudes were high in TAN, with whole crude values ranging up to 2.0 to 3.0 mg/gm TAN and corresponding NAN values from 1.9 to 2.8 mg/gm. Even though these crudes represented a significant profit opportunity, there was a legitimate concern that processing these high acid crudes could result in significant high temperature corrosion of the refinery carbon

steel processing equipment. If this corrosion was not controlled, the failures could result in loss of containment, which would be both an environmental and a safety hazard. Corrosion failures could also result in production outages and reduction of crude charge. These problems could erase the opportunity profit differential and create a sizeable operating loss rather than a profit. It would be essential to control and monitor the corrosion in order to realize the potential profit gain from processing these high acid crudes.

## Crude Oil

In order to better understand the magnitude of the corrosion potential, it is necessary to provide a better definition of the crude oil and its acidic characteristics. For comparative purposes, two samples of the same crude charge were taken 10 days apart. Values of the acidic characteristics of these crude samples and side cuts are shown below in Table 1.

**Table 1**

Stream	Sample 1			Sample 2		
	TAN	NAN	NAN as a % TAN	TAN	NAN	NAN as a % TAN
Whole Crude	2.2	1.50	68.18	2.50	1.05	40.00
2 Stream.	0.69	0.48	69.57	0.57	0.27	47.37
4 Stream	2.86	2.10	73.43	2.65	1.66	60.38
6 Stream	3.08	1.50	48.70	3.02	1.90	62.91
7 Stream	2.75	2.20	80.00	2.92	1.96	65.52
9 Stream	2.72	1.96	72.06	2.08	1.65	82.50
10 Stream	2.80	1.90	67.86	2.99	0.97	32.44

TAN is the standard ASTM D664 analysis that is generally recognized as the global standard for identifying the acid content of the crude. Since this test and other TAN tests are subject to interference, GE developed a NAN test that is more specific for naphthenic acids. NAN is a proprietary test which separates the active carboxylic acid species from the other organic and inorganic acids like esters, phenols, lactones, resins, salts of heavy metals, additives and detergents. The resulting sample is then titrated with KOH to yield the NAN value, which is

technically a more accurate assessment of the potential corrosivity of the fluid.

The snapshot of the two separate values of the same crude from the table above not only underscores the high level of naphthenic acids being processed at Cross, but also demonstrates both the variability of acid distribution to the various product streams and the variability of the ratio of corrosive naphthenic acids (NAN) to the total acid (TAN). These variabilities add to the extremely complex nature of naphthenic acid corrosion and highlight that a treatment protocol based simply on a crude charge TAN would have a low probability of successfully controlling naphthenic acid corrosion.

Three key points about TAN, NAN and the data from the table should be noted:

- > TAN analyses are subject to interferences
- > Distribution of acid content can vary from within the same crude
- > Ratio of naphthenic acids NAN to TAN may not be consistent for the same crude

## Corrosion Detection and Monitoring

From the inception of processing high acid crudes, monitoring for corrosion was always a high priority. Through the years several different techniques were used. None of these techniques individually provided a complete picture of the range or degree of protection, but when all the techniques were used simultaneously, the data provided a higher level of assurance of program effectiveness. Recent developments by GE in predictive modeling and corrosion monitoring are currently being evaluated in the refinery. These new products promise to provide an enhanced treatment program and a much more detailed analysis of the corrosion control effectiveness over a significantly wider area of the system.

## Period 1 Caustic

In 1993 the refinery began processing the higher acid crudes, and caustic addition was implemented to control the potential corrosion. Caustic was fed at whatever rate was necessary to control the TAN value of the number 6 stream to a TAN of <0.5 mg/gm., and the other high temperature streams all fell into a TAN range < 0.1 mg/gm.

Caustic was injected directly into the transfer line between the atmospheric heater and the atmospheric column. At times the addition rate of the caustic required to neutralize the naphthenic acids was as high as 500 ptb of crude charge. Rapid fouling and frequent acute failure of the transfer line downstream of the caustic injection characterized this period. Once the transfer line failure mode became a chronic issue, this area of the unit was monitored closely by operations and inspection personnel to detect the earliest signs of failure. In order to facilitate rapid repair, replacement spool pieces fabricated with Hastelloy were maintained on site so that the system could be isolated, the spool piece changed and the unit returned to operation as quickly as possible. Even with the heightened monitoring, early detection and the readily replaced hastelloy spool piece, injection of the caustic proved to be expensive. Between December 1994 and October 1996 the spool piece was replaced 10 times, with each occurrence resulting in down time and lost production. The longest run between failures was 160 days, and the shortest run was 28 days. In addition to corrosion of the spool piece, corrosion was also noted in the high temperature section of the atmospheric column, associated piping elbows and nineties. Corrosion also occurred to the carbon steel trays, flat bar support member welds, some of the side stripper welds and in the flash zones of the atmospheric column.

Corrosion in the vacuum column manifested itself as thinning of the schedule 40 transfer line, which was replaced with schedule 80 carbon steel in 1996.

The corrosion was expensive; each replacement of the spool piece related to at least one day lost production, and in some cases lost production exceeded that level. At the time, the disruption to operations was not only expensive but also frequent and eliminating the problem rapidly became a high priority.

The caustic contributed to fouling of downstream heat exchange equipment, with the most severe fouling in the hottest streams like the flux (Vacuum Residuum), 10-stream and also in the diesel pumparound exchanger and side strippers. The rate of fouling was such that the crude and vacuum units had to be shut down and cleaned an average of every 15-18 months and sometimes even more

frequently. Additionally, by the end of run, generally the last 3-6 months before shutdown, the loss of inlet furnace temperature was such that the crude charge had to be reduced by as much as 10% in order to maintain the appropriate temperature profile in the vacuum unit.

In addition to the fouling and corrosion issue, operation of the hydrotreater was also negatively impacted by the higher acid crudes and the addition of caustic. The biggest problem seen in the hydrotreater was rapid increase in pressure drop across the preheat train and the catalyst bed. These issues necessitated frequent outages to clean the preheat train and skim the catalyst bed. Frequency of these cleaning operations corresponded with outages on the crude and vacuum units so they did not typically result in throughput loss but did translate to added maintenance expense.

The impact of processing high acid crude and using caustic to mitigate the corrosion can best be summed up as costly and unreliable. It was costly because the total cost of the program included maintenance expense, lost production debit and equipment replacement. It was unreliable because it was impossible to accurately predict when or where the fouling and corrosion would occur.

Because of the corrosion and fouling problems on the crude, vacuum and HDS units associated with the addition of the high acid crude and caustic; refinery management decided to evaluate replacing caustic with a state of the art phosphate ester based corrosion inhibitor. The overall objective was to eliminate the caustic addition and associated fouling, while controlling the high acid crude corrosion.

Phosphate ester chemistry was chosen because it was, at the time, considered the best available corrosion control technology. Corrosion control resulted from the formation of a very tenacious, stable and highly resistant iron sulfide/iron phosphate film on the metal surface.

During this period, there were no other ancillary problems associated with processing the high acid crudes. Even though the refinery only had a single stage desalter, dehydration efficiencies were good and the high levels of caustic being added controlled overhead chlorides to a low enough con-

centration that overhead corrosion was simply not a significant problem.

## Period 2 Various Phosphate Esters & Caustic Program

The Phosphate ester overlay of the caustic program was initiated in mid 1998 and was continued until November 2001 when the caustic was discontinued. Because of various program considerations several different suppliers and several different commercially available phosphate ester products were used during this period.

Caustic injection was continued into the transfer line at a rate to achieve a TAN in 6 stream <0.5 mg/gm. Phosphate ester injection was implemented into the crude charge, the atmospheric bottoms, number 7 stream pumparound, number 7 stream reflux, number 9 stream reflux and the diesel pumparound.

Injection equipment for the commercially available phosphate ester products is a critically important aspect of the applications technology. Chemical injection line plugging occurred necessitating the need to remove and clean out the injection quill. In another instance, injection of the neat inhibitor, without carrier, resulted in failure of the quill, which resulted in impingement of the neat inhibitor directly on the internal wall of the receiving stream, and in the failure of the process piping downstream of the injection point. The plugging and corrosion both had a negative impact on the program reliability and safety.

Because there is no one completely effective monitoring tool for evaluating the effectiveness of the high temperature corrosion control program, a number of tools have been used to monitor the program. These included Electrical Resistance Probes, UT thickness, corrosion coupons, iron, nickel and iron to nickel ratio, unit inspections and metallurgical examinations.

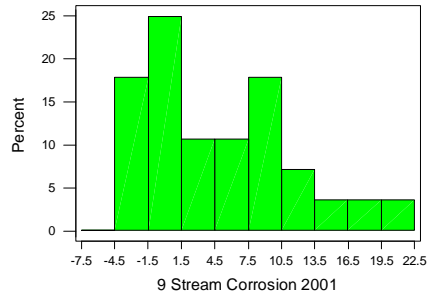
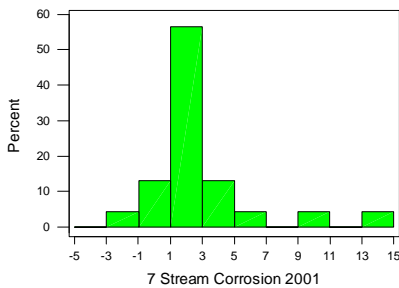
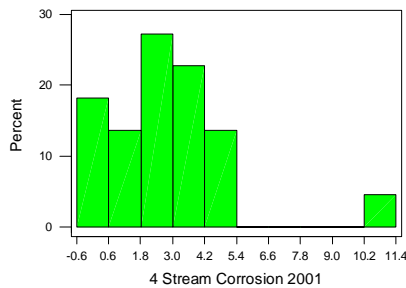
Data from 1998 to 2000 indicates that corrosion rates and corrosion control were generally acceptable. Corrosion coupons, Electrical Resistance Probes, UT, inspections and iron:nickel ratio were used to monitor the program results.

**Table 2: Corrosion Coupon Data (mpy)**

Stream/ Corrosion	3rd Quarter 98	4th Quarter 98	1st. Quarter 99	2nd Quarter 99	3rd Quarter 99
7 Stream	0.39	0.40	0.44	36.6	0.29
9 Stream	3.65	3.50	2.28	2.28	2.22
10 Stream	3.02	2.90	2.84	1.84	1.99
Atmos Btms			12.95	12.95	11.49
	2nd 2000	3rd 2000			
7 Stream	0.9	0.03			
9 Stream	2.4	0.01			
10 Stream	1.99	0.2			
Atmos Btms	2.2	23.4			

High temperature Electrical Resistance probes were used beginning in 2001. Some histograms of the ER probes during this time period in Figure 1:

**Figure 1: Electrical Resistance Probes**



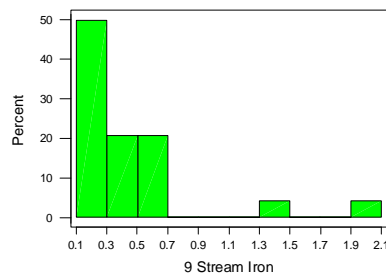
Results of the Electrical resistance probes indicate that the corrosion rates were erratic, with some corrosion results indicating negative corrosion rates. However, the bulk of the data indicates that corrosion rates were generally being controlled to less than the targeted 10-mpy rate.

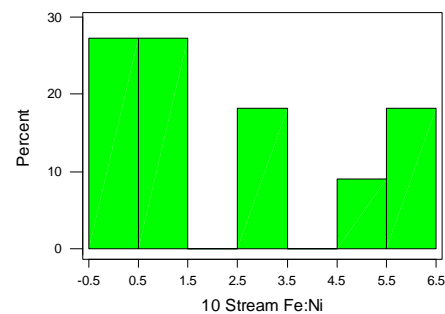
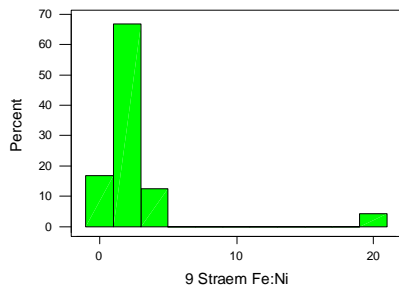
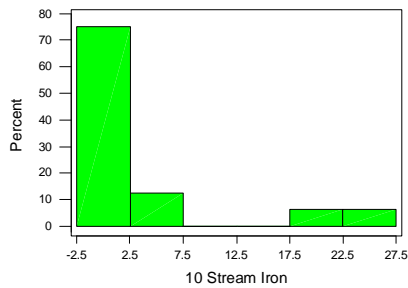
UT thickness readings are taken in the refinery by an independent third party service.

Thickness readings on all the towers, strippers, heater tubes and transfer lines in all the high temperature areas of the refinery are taken at regular intervals. Thickness checks taken in this time frame did not indicate that any metal loss was occurring to any of the points regularly evaluated.

Iron and iron:nickel ratio were used to provide a sense for the overall effectiveness of the corrosion treatment. In the bottom streams from the atmospheric column and the vacuum column, increasing iron to nickel ratio would suggest that corrosion was occurring at some point in the system. Likewise, tracking changes in concentration of the side streams can be used to assess the overall effectiveness of corrosion control of the side stream loop. Iron and iron:nickel ratio data are reviewed in Figure 2:

**Figure 2**





The graphs indicate that several periods of elevated iron content and iron:nickel ratios occurred. Further examination of the data indicated that on several of these occasions the spike in iron was most likely directly related to incoming raw crude. However, other spikes in iron and/or the ratio of iron:nickel were ascribed to increased corrosion activity, which could be directly related to spikes in naphthenic acid content resulting from loss of caustic injection.

As with the UT analysis, inspections during the period did not reveal that significant corrosion was occurring in the system, and there were no corrosion failures or production outages attributable to corrosion events.

Even though the monitoring tools used were lagging indicators of corrosion, they did in time indicate that the phosphate ester based programs achieved acceptable control of corrosion. Corrosion did not severely restrict or limit operations reliability. Unfortunately, the real limit to operational

reliability, as with the caustic program, was fouling. In addition to the caustic fouling previously noted, fouling of control valves, small diameter pipe, strainers on pumps and wash nozzles and column and stripper trays was rampant. Plugging of these would limit tower operations, inhibit product separation, and reduce unit throughput. In the worst case scenario, a unit shut down was required to clean up the foulant.

Changing the strainers, which had to be done to protect downstream equipment, was both a maintenance expense and more importantly a safety hazard. There were numerous occasions when the off line strainer plugged up immediately after being put on line and the previously on line strainer had to be cleaned hot and returned to service quickly to prevent complete plugging and loss of flow.

Even with rigorous monitoring and cleaning of the strainers, the atmospheric column experienced phosphorus fouling, ultimately requiring a unit shutdown to clean out the affected area of the tower. After this tower cleaning, the supplier and their program were changed. The new supplier applied a program that was a blend of sulphur and phosphate ester.

There were no ancillary problems noted with the desalter efficiencies or overhead corrosion control. Since caustic was still being applied to the crude charge, overhead chlorides were low and corrosion of the overhead condensers was not an issue.

### Period 3 Sulfur and Phosphate Ester

A combination sulphur and phosphate ester program was initiated in June of 2001, and by November the caustic had been removed from the program and phosphate ester injection rates had been increased significantly. The refinery was down for a turnaround in December of 2001 and back up again in January of 2002.

Corrosion was still relatively benign, with a pinhole leak in 2 stream as the only significant event and the fouling continued even though the caustic had been removed from the program. Fouling in the preheat, strainers and valves continued unabated and was most severe in streams 9 and 10 and the stream 10 injection system plugged, which resulted in loss of chemical injection into this stream. Fouling also affected the Hydrotreater unit in the form of preheat exchanger fouling, reactor bed plugging

and ultimately in necessitating the replacement of catalyst in April of 2002.

Even though there was no significant naphthenic acid corrosion, there was collateral corrosion to the overhead condensing system on this program. A failure of the overhead condensers occurred in November 2002. The corrosion was driven by an increased level of chlorides in the overhead condensing system, which was associated with removing the high level of caustic from the treatment programs. The increased corrosion activity was expected, and it occurred despite the addition of a second stage desalter and an overhead condenser water wash system.

Other new problems also surfaced with this program. In December of 2002 the relatively new hydrotreater catalyst began to show signs of acute of activity loss. This loss manifested itself in both product quality problems as well as operational difficulty on the unit. It very rapidly became impossible to meet product sulphur specifications. The acid number of the finished products rose above specification range, as did the saturates level and the color. On the operations side there was increased reactor temperature and increasing pressure drop across the reactor bed. Sulphur values during the affected time are listed in Table 3:

**Table 3**

Stream Number	Typical Sulfur In %	Typical Sulfur Out %	Sulfur Out During Time
4	0.55	0.01	0.14
6	0.61	0.02	0.13
7	0.67	0.01	0.19
9	0.88	0.01	0.27
10	0.97	0.01	0.28

The loss in activity resulted in an outage to replace the catalyst. It was removed from the reactor, examined and analyzed to determine the root cause of activity loss. Examination indicated the presence of a phosphorous coating, which was sufficient enough to have caused the loss of catalyst functionality. Analytical data from analysis of the catalyst removed from the crippled reactors confirming that the catalyst deactivation was driven by phosphorous is detailed in the Table 4.

**Table 4**

Metal	RX1			
	ppm	RX1 Top	Middle	RX2 Bottom Top Tray
Al	34.5	35	35.6	<0.05
As	0.27	0.23	0.16	0.04
Ca	0.07	0.04	0.03	0.05
Co	0.01	0.01	0.01	0.02
Fe	0.14	0.11	0.06	59
Mo	13.2	12.8	13.1	0.29
Na	0.12	0.08	0.07	0.61
Ni	3.66	3.01	3.05	0.19
P	4.29	4.5	4.16	0.13
Si	1.1	1.0	0.8	30.9

Metal	RX 2			
	RX 2 Top	RX2 Middle	Bottom	Top Tray
Al	35.7	35.8		
As	0.22	0.29		
Ca	0.03			
Co	0.01			
Fe	0.06	0.01		55.1
Mo	13.0			
Na	0.1			
Ni	3.1	3.77	3.44	3.01
P	4.24			
Si	0.9			

The Lost Profit Opportunity from these two events was significant. Not only was there an unplanned refinery outage, resulting in loss production at a critical time, there was also degraded product quality for 4 months, increased maintenance cost, increased safety issues with increased worker exposure and a very premature catalyst replacement. The impact on refinery profitability was significant.

The loss of hydrotreating capability in 8 months, the forced unscheduled plant outage to change the catalyst, the cost of the shut down, the cost to replace the catalyst, the corrosion failure of the overhead heat exchangers and associated costs were all deciding factors in driving the change of the supplier and their programs. In February 2003 the change was made from the previous supplier and the low sulphur phosphate ester program to the GE sulphur-based corrosion inhibitor, which is still used today.

## Period 4 GE Sulphur-based Corrosion Inhibitor

Test work performed by GE research scientists in The Woodlands facility suggested that their recently developed and commercially unproven sulphur-based inhibitor might not provide equal system corrosion protection to the phosphate esters, but it would provide adequate corrosion protection and would eliminate the fouling that was being driven by the phosphate ester. The trade off was eliminating the phosphorous fouling and catalyst poisoning, which had been the principal problems, at the expense of the possibility of increased corrosion activity. The only key question mark was the actual level to which corrosion might increase. The obvious need to eliminate the fouling and catalyst poisoning justified the decision to change to the sulphur-based corrosion inhibitor.

After 19 months of continuous operations on the GE Water & Process Technologies sulphur-based corrosion inhibitor, the data from the available monitoring tools indicate that not only is the high temperature naphthenic acid corrosion being controlled adequately but it is also being controlled as well as it was during the various phosphate ester programs that were previously used.

UT monitoring is done by a third party and GE. UT points had been selected to give a broad picture of overall system corrosion with many detection points located in high sheer stress areas where corrosion would be expected. UT check points are located on atmospheric and vacuum towers, heater tubes, strippers, transfer lines and system piping. Some representative thickness data are listed in the table below:

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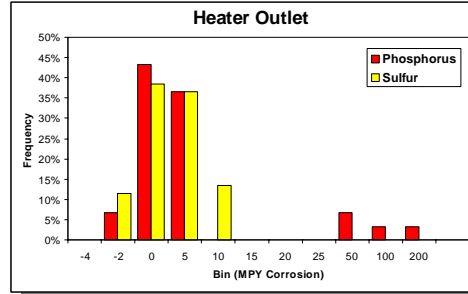
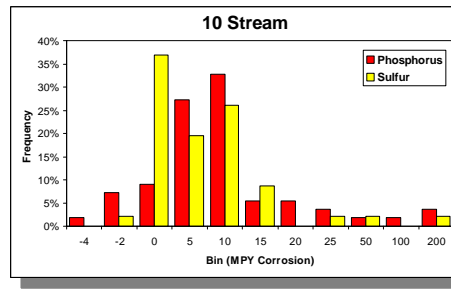
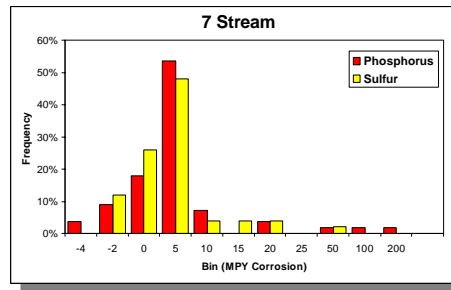
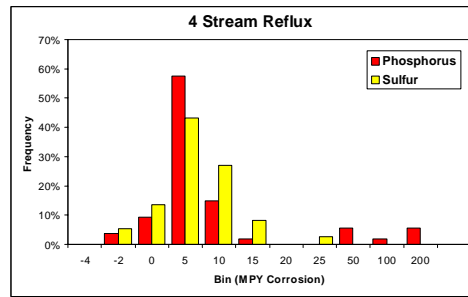
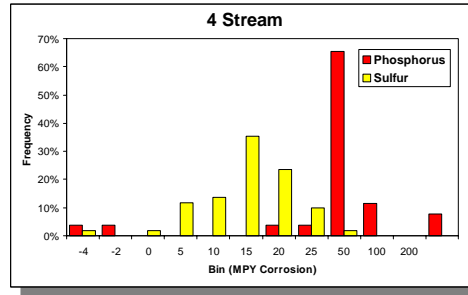
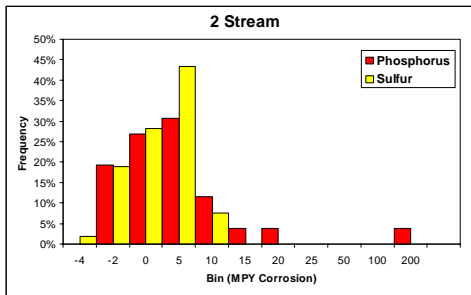
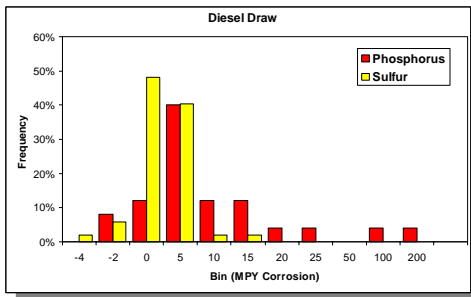
**Table 5**

Date	Stream	Location	Nominal	Reading
2-27-03	4	Below ER Probe 3" Sch 80	0.300	0.237
5-22-03	4			0.236
4-12-04	4			0.234
1-29-03	4	P3317 Discharge 2" Sch 40		0.153
4-01-04	4			0.153
2-27-03	9	Reflux at Strainer 2" Sch 40	0.154	0.148
5-22-03	9			0.145
4-12-04	9			0.142
2-27-03	7	Pump around at strainer 3" Sch 80	0.300	0.220
5-22-03	7			0.236
4-12-04	7			0.226
9/30/03	10	P3313 Discharge		0.134
1-29-03	10	P 3313 Discharge 2" Sch 40		0.134
4-12-04				0.134
9-30-02		P3319 Discharge 2" Sch 40		0.125
1-29-03				0.125
4-12-04		P3319 discharge		0.125
2-27-03	10	Reflux Strainer 2" Sch 40	0.154	0.137

Date	Stream	Location	Nominal	Reading
5-22-03				0.135
4-12-04				0.141
2-27-03	4	P3317 Suction 3" Sch 80		0.225
5-22-03	4			0.224
4-12-04	4			0.225
2-27-03	4	Reflux at tower		0.187
5-22-03				0.187
4-12-04				0.187
9-30-02		Flux 2" Sch 40		0.110
12-8-03		Flux		0.110
9-30-02		Flux 3" Sch 80		0.231
12-8-03				0.230

UT data does not show any significant wall loss in any of the points that are monitored.

Corrosion data as analyzed by Electrical Resistance Probes also indicate that corrosion is being controlled as affectively as the phosphate esters programs.



Since the sulphur-based corrosion inhibitor was implemented, no outages related to naphthenic acid corrosion in the high temperature zones of the unit or to low temperature overhead condensing system have occurred. The unit did experience corrosion of the diesel pumparound heat ex-

changer. However, the mechanism of corrosion was not related to high temperature naphthenic acid corrosion or sulphidation but was related to deposition of ammonium chloride salts. A diesel pumparound pump impeller was replaced due to corrosion. The impeller was cast iron and the mechanism of corrosion was determined by metallurgical examination to be sulphidation. A second pump impeller on stream 7 was also replaced and metallurgically examined. The metallurgical analysis determined failure mechanism to be erosion and not naphthenic acid corrosion.

All the current monitoring tools indicate that corrosion control with the GE sulphur-based corrosion inhibitor is being achieved.

The program has also delivered on the fouling problem. The most significant advantage of the GE sulphur-based corrosion inhibitor has been the elimination of the fouling that was seen with the caustic program and the phosphate ester programs. The units have been on stream for 18 months, and some heat exchanger heat transfer loss was experienced and resulted in a slight 5% reduction in crude throughput. However, with the replacement of the diesel pumparound heat exchanger, which occurred in July all the lost heat exchange has been regained and throughput has returned to maximum levels.

Furthermore, the sulphur-based corrosion inhibitor has not shown any negative affect on the catalyst activity and product sulphur specifications are being easily achieved. Evaluations of the finished products by GE Water & Process Technologies research scientists have not been able to find any traces of the inhibitor and this suggests that the corrosion inhibitor is being removed from the product streams in the hydrotreating process.

The benefits of the sulphur-based corrosion inhibitor are clearly significant:

- > Based on equipment inspections, UT probe analysis, ER probes, chemical and metallurgical analyses the sulphur-based corrosion inhibitor has provided corrosion protection similar to that of traditional state of the art phosphate ester programs.
- > The sulphur-based corrosion inhibitor has eliminated fouling that was experienced with previous programs.

- > The sulphur-based corrosion inhibitor has eliminated the source of catalyst deactivation.
- > Controlling the fouling and corrosion have significantly reduced the refinery maintenance budget.
- > Controlling fouling and corrosion have significantly enhanced the reliability of operations.
- > Controlling the fouling and corrosion have significantly enhanced worker safety.
- > Controlling the fouling and corrosion have significantly enhanced refinery profitability.

## Summary

Since high acid crudes are often priced lower than comparable crudes, processing them can have a huge positive impact on the refinery profitability. In our refinery processing, these high acid crudes have resulted in an increased yield of higher value products but some of the realizable value had been offset by the hidden costs and operational difficulty associated with corrosion control programs. These costs negatively impacted the perceived or calculated incremental profit potential, but utilizing new sulphur-based corrosion inhibitor from GE Infrastructure Water & Process Technologies has allowed the refinery to capture the profit gain of higher product yields and controlled corrosion without the operational problems caused by caustic, phosphate ester and the combined sulphur phosphate ester programs