The cost of poor amine operations

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Data from 62 US refineries have highlighted the expense of operating refinery amine units. Costs of the less well managed plants could be $1 million a year more than those of better-run units.

The Amine Best Practices Group (ABPG) was formed on the basis of interest by many refiners, both major and independent, who had expressed interest in evaluating their own amine unit operations in relation to others.

While some major refiners have internal 'best practices' groups that evaluate their own amine unit operations, most small and independent refiners do not. However, the results of these internal 'best practices' groups offer no conclusions about comparison with other amine unit operations.

In addition to such comparison, refiners would like to look upstream of the SRU for solutions to problems causing SRU upsets and trips. To this end the ABPG was formed, as no real-world data existed that would allow any individual refiner to evaluate his amine unit operations in relation to others in the industry. The history of the ABPG is short. It was formed in late 1993 when a group representing the refining industry, design engineering and an independent consultant met to discuss the possibility of developing a real-world database for amine unit operations. The goal, or vision, of the ABPG was established to accumulate a database on amine unit operations and become a clearing-house for the analysis and distribution of such data to the refining industry on a global basis through articles in industry trade journals, and symposiums.

The ABPG developed a comprehensive amine unit survey questionnaire that was mailed to refiners with a clear statement that the responses would be held in confidence by an independent consultant. Although members would have access to the data for the purpose of analysis and conclusions, the individual response would be coded to protect the confidentiality of the data.

The ABPG also developed an amine unit *Good Practices Manual* (*GPM*) that defines the function or purpose of each item of equipment in a typical amine unit. It includes normal operating ranges of process parameters, typical instrumentation, suggested monitoring intervals, causes and consequences of deviations from target values, and suggested action for correcting deviations.

This GPM was developed simply as a guideline for *typical* amine unit operations and is not meant to address amine unit design. It is not the intention of the ABPG to establish or evaluate amine unit design criteria, but only amine unit operations.

The 1994 survey questionnaire developed by the ABPG resulted in the collection of operating data from 62 refinery amine units utilising monoethanolamine (MEA), diethanolamine (DEA), methyl diethanolamine (MDEA) and diglycolamine (DGA). Tail gas treating units are specifically excluded from the database because they are a special case and the objective of the survey questionnaire was to evaluate amine units upstream of the SRU.

Quartile rankings were developed by manipulating the data based on a number of measures of amine unit performance. A summary of these quartile measures developed by the ABPG is shown in Table 1. One of the first conclusions to be drawn from the survey database is that amine units can be very expensive to operate. There are significant operating cost differences indicated between well-run amine units and poorly-run ones. This article

Selected quartile average values

Item	Q1	Q2	Q3	Q4	Units
Regen reboiler heat input	590	772	923	1276	Btu/gal feed
Amine circulation rate	158	307	401	793	Gal/Mscf acid gas
Cost of contamination	166	659	1368	3629	$/yr/MMscfd gas
Regenerator reflux ratio	0.7	1.6	2.6	7.2	Moles/mole acid gas
Amine makeup rate	2.6	8.5	18	38	Lbs amine/MMscf gas
H_2S exceedences, gas	0	2.5	7	26.7	Times/year
H_2S exceedences, liquid	0	0	1.5	5	Times/year
Unscheduled shutdowns	0	0	0.9	2.9	Times/year
Other units limited by amine	0	0	0.9	11.5	Times/year
SRU upset by amine unit	0	0.9	2.5	14.4	Times/year

Table 1.

Overall amine unit costs, First and Fourth quartile operations

(See Table 1 for process value units)

			First quartile		Fourth quartile		
Assumptions	**Units**		**Proc val**	**Annual costs**	**Proc val**	**Annual costs**	
Gas treated	MMscfd		60		60		
H_2S content	Vol%		4.4		4.4		
CO_2 content	Vol%		1.5		1.5		
Type amine used			DEA		DEA		
Amine concentration	Wt%		28		28		
Net loading, H_2S	M/M		0.3		0.25		
Net loading, CO_2	M/M		0.1		0.08		
Circul amine inventory	Gals		30 000		30 000		
Op labour, inc super	Men/shift		1.5		1.5		
Purge for 400ppm NH_3	GPM		1		1		
Capital investment	$MM		10		10		
Unscheduled shutdowns	Days/yr		0		6		
Calculations		**Unit costs**					**Delta cost**
Amine circulation rate	GPM		720		864		
Pumping cost, power	$/kWh	$0.05		$59 618		$71 541	$11 924
Labour costs	$/h	$30.00		$394 200		$394 200	$0
Amine makeup costs	$/lb	$0.50	2.6	$28 470	38	$416 100	$387 630
Regen heat input	$/MMBtu	$3.33	590	$743 335	1276	$1 929 143	$1 185 808
Cooling water cost	$/MMBtu	$0.15		$33 484		$86 898	$53 415
H_2S heating value lost	Btu/scf	$3.33	600	$1 925 273	600	$1 925 273	$0
Sulphur recovered	$/LT	$40.00		($1 452 846)		($1 428 963)	$23 882
Condensate recovered	$/gal	$0.01		($294 479)		($764 247)	($469 768)
Condensate consumed	$/gal	$0.01		$5276		$5553	$277
Contamination cost	$MMscf	Reported	0.4	$8760	10.15	$222 285	$213 525
Cost of off spec prods	$/event	Unknown	0.6		27		
Cost of unsched downs	$/event	Unknown	0		3.5		
Cost of SRU upsets	$/event	Unknown	0		15		
Maintenance cost	% of capital	4		$400 000		$400 000	$0
Working capital	Amine value			$35 280		$35 280	$0
Capital charge	% of capital	13		$1 300 000		$1 300 000	$0
Total costs				**$3 186 371**		**$4 593 063**	**$1 406 692**

Table 2.

compares a hypothetical first quartile amine unit operation with a hypothetical fourth quartile unit operation and explores some of the cost differences.

The analysis of the database indicates that a poorly-run amine unit could cost up to US$1.5 million more a year to operate than one well run. With all the current pressure on control of operating cost, this indication alone should stimulate refinery managements' interest in developing a programme to investigate the operation and operating costs of their amine units.

The operating costs listed in Table 2 indicate the savings for a hypothetically well-run amine unit over a poorly-run one of similar size. The principal elements of the cost differential include regenerator heat input ($0.7 million), amine makeup ($0.4 million), and contamination ($0.2 million). The costs of off-spec product, shutdowns and upsets may be another large factor in refineries that experience loss of throughput due to amine unit problems. There is a strong possibility that corrosion costs would also be a significant cost difference if data were available for evaluation.

The magnitude of the cost differential should be enough to have two effects. It should make individual refiners examine their own operations and operating costs in enough detail to effect cost reductions where appropriate; and it should make the ABPG develop a questionnaire updated to evaluate operating costs in considerably more detail and explore the relationship between operational data and operating costs.

The unit costs associated with operating an amine unit will vary widely from refinery to refinery. A number of simplifying assumptions must be made to give a generalised cost comparison. These assumptions are discussed here in sufficient detail to allow individual refiners to understand them and change unit costs to reflect their own operations. For comparision, costs are developed on a hypothetical average-sized amine unit as defined by the amine benchmark survey. The unit treats a total of 60MMscfd of sour gas and removes 100LTD equivalent hydrogen sulphide. For heat balance reasons, the gas is assumed to contain carbon dioxide at one-third of the hydrogen sulphide content. The assumed amine type, for purposes of assigning an amine cost, is DEA. Solvent is circulated at a concentration of 28wt%, and at a rate as needed to give the reported net loading indicated in Table 2.

An average ammonia content of 400ppm in the sour gas is assumed for the purpose of computing a regenerator reflux purge rate necessary to keep the reflux below 5000ppm ammonia. Circulating inventory of amine is assumed to be 30 000 gallons. Operating data are taken as appropriate from Table 1 or from a review of actual surveyed units comprising the upper and lower ranges of performance. Heat value is difficult to assess, particularly where low-pressure steam is involved. For this comparison, the assumed heating value is based on $20 crude at 6MMBtu/bbl, or $3.33/MMBtu. Hydrogen sulphide removed from the fuel gas is valued at its fuel value because it must be replaced with incremental fuel gas. While burning the hydrogen sulphide is unrealistic from a pollution standpoint, it does provide a basis for computing a value for hydrogen sulphide. Removed hydrogen sulphide is valued at an equivalent elemental sulphur value of $40/LT. The fourth quartile plants exhibited significantly more upsets and emergency trips, and so a small reduction in sulphur recovered is assumed.

The cost of amine losses is based directly on the reported makeup rate per MMscf of gas treated, adjusted for the volume of liquid hydrocarbon treated, and an assumed cost of DEA. These makeup rate data should be good, though simply asking the purchasing agent how much amine was bought last year will elicit the correct number. DEA was chosen for the comparison because the largest number of survey respondents used it, and because the survey showed no significant difference in actual operating parameters between the various amine types. However, the expected difference in the selectivity of MDEA towards hydrogen sulphide over carbon dioxide, compared with MEA and DEA, was seen in the survey data.

No cost has been assumed for treated product being out of legal compliance with operating permits, and in fact the survey did not address legal compliance. It addressed only compliance with refinery targets. Likewise, because of the large variation among refineries, no costs were assumed for off-specification product, SRU upsets, or unscheduled amine unit downtime.

Each refinery must evaluate its own cost of upsets and lost production. Additional costs that could be included because of amine unit operating limitations are the cost of products downgraded to refinery fuel or flared, and of retreating products that cannot be sold, the loss of refinery throughput, or the inability to process lower-cost, high-sulphur crude oil.

Such costs could be high, and probably represent a

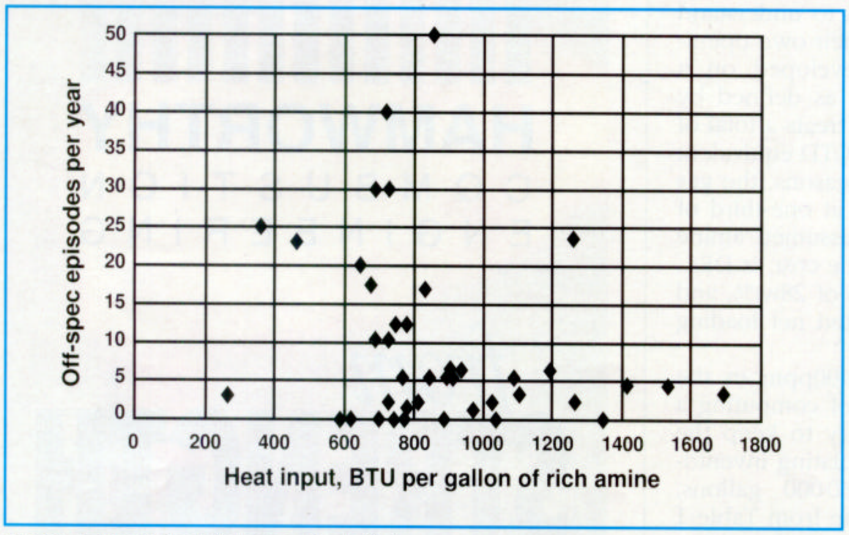

Figure 1. Regen heat input against off-spec gas.

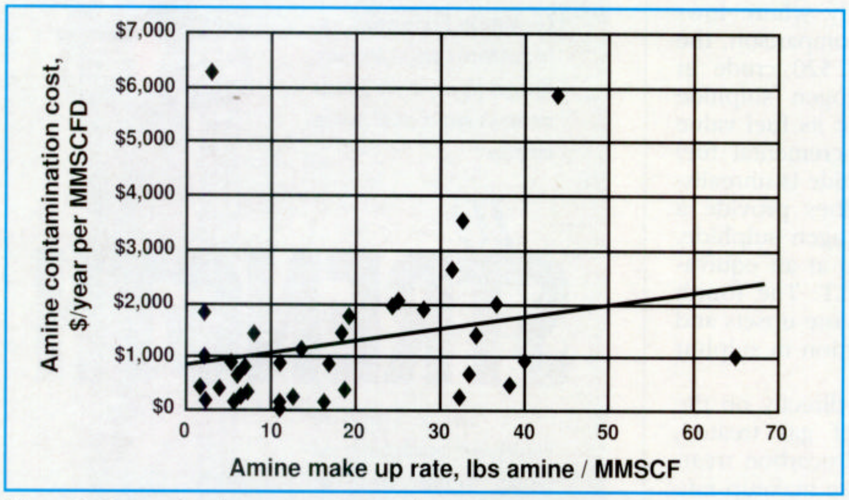

Figure 2. Contamination cost against makeup rate.

large additional difference between well-run and poorly-run units. The survey showed that poorly-run units tended to be much less reliable than those run well.

Another cost of poor amine unit performance that is difficult to quantify is the risk inherent in an emergency trip of the sulphur recovery plant. Even if the emergency shutdown system works perfectly, a trip usually releases a significant quantity of hydrogen sulphide, and perhaps ammonia, to the flare. Sulphur recovery plant trips are much more than just a nuisance.

The cost of amine contamination, which in the survey included filtration, reclaiming, and costs of additive chemicals, is taken directly from the survey database. In the survey, the major difference between the first and fourth quartile contamination costs is that of additives. Several refiners reported using anti-foam or corrosion inhibitor, but also reported no cost for additives. The reported contamination costs, therefore, almost certainly understate the real cost, and do not include the cost of corrosion. Corrosion will, of course, vary significantly as between well-run amine units and poorly-run ones.

Data from the survey is insufficient for quantifying corrosion costs, though fourth quartile refineries do exhibit much higher heat-stable salts levels and filtration costs than do the first quartile refineries.

Assuming that acid gases left in treated streams would have caused corrosion elsewhere in the refinery, there is an additional corrosion cost to be avoided by properly operating the amine unit. Again, no data are available for evaluating this credit against the cost of amine unit operations. It is to be expected that poorly-run amine units will see more downstream corrosion than well-run ones.

Steam to the regenerator reboiler and condensate recovery are based on heat input factors taken from the survey database for the quartiles in question. Condensate consumed is used to make up reflux purge volume and to blend amine makeup from the 85 per cent supply strength to operating strength.

Utility costs are assessed at nominal values and are indicated in Table 2. To represent the true economic cost of operating the amine unit, nominal costs of maintenance and capital represented as percentages of an assumed capital cost of the amine unit have been included. It is expected that a poorly-run amine unit will have a significantly higher cost of maintenance than a well-run one, but the survey database does not provide the information to evaluate this properly. Working capital is included as the value of the amine in the circulating inventory.

Tentative conclusions

The 1994 ABPG amine unit survey questionnaire was aimed at gathering general operating information rather than specific cost data. It is thus difficult to derive cost-reduction conclusions from the data available in the database, though some comments are appropriate.

Heat input is the largest measured element of cost. The survey questionnaire asked operators whether heat cost was a factor in setting the steam rate to the regenerator. Of the 62 responses, 47 replied No and 15 Yes. This would suggest that most refiners prefer to over-strip their amine slightly rather than risk an off-specification product because of under-stripped amine. The survey data tended to support such a conclusion.

The units with higher-frequency off-specification product tend to be the ones with lower regenerator heat input per gallon of rich amine feed. This point is graphically illustrated by Figure 1, which is a plot of regenerator heat input in Btu per gallon of rich amine fed to the regenerator versus the number of off-spec episodes per year.

The correlation becomes more clear if the data points with heat input below 600Btu per gallon are discarded as being unrealistic or erroneous. The amine units operating with heat input between 600 and 850Btu per gallon appear to be experiencing the most off-spec episodes. By contrast, the amine units operating with heat input above 850Btu per gallon appear not to have serious off-spec problems.

It is interesting that, on average, there is no significant difference in heat input between those operators who say the cost of heat is important and those who say it is not.

Amine losses represent the second-largest cost category. Intuition might suggest that refiners with high replacement costs would, by simple dilution, have a low cost of contamination, but the survey data tend to disagree. There is a weak correlation showing that plants with high losses also have high contamination costs. This can be seen in Figure 2, which relates the cost of contamination in dollars per year per MMscfd of gas treated to the amine makeup rate in pounds of pure amine per MMscf of gas.

The data points grouped in the lower left hand corner of Figure 2 represent the first quartile units. The data points spreading out from them tend to move up and to the right, as indicated by the trend line. As expected, contaminated amine leads to foaming and corrosion and high amine losses. One would expect a correlation between the cost of amine filtration and the frequency of foaming episodes; that is, refiners who spend a significant amount on filters should have fewer foaming episodes. However, the survey data tend not to support that conclusion.

There is, in fact, a slight opposite correlation. Those refiners who suffer most from frequent foaming also tend to spend most on filtration. This leads to the tentative conclusion that stopping corrosion, a common cause of both particulates and foaming, saves money on two additional fronts: filtration and foaming.

There does seem to be a weak correlation between the fraction of amine that is carbon-treated and the frequency of foaming episodes. Those who carbon-filter-treat a greater proportion of their circulating amine seem to have fewer foaming episodes. Combining this conclusion with the previous one suggests that refiners who carbon-filter-treat more of the circulating amine may have a lower overall filtration cost. The scatter of the data is too much to draw this conclusion directly from the survey database.

The ABPG had expected to see some difference in the cost of operation related to the type of amine used in the amine unit. Other than the selectivity regarding carbon dioxide, as already mentioned, no differences were observed. Heat input per gallon, circulation per mole of acid gas, loss rate and contamination for units using MDEA were all essentially the same for amine units using MEA or DEA.

Not enough amine units using DGA were reported to draw any meaningful conclusions for this amine, suggesting that refiners tend to operate all amine essentially the same, without regard to the inherent differences between the types of amine available in the market. This further suggests that some training may be needed for refinery operators (and engineers) if they are to capitalise on the differences.

Follow-up survey

The members of ABPG are planning to conduct a follow-up survey in late 1995. This survey questionnaire will focus more on the costs of operating amine units, and on factors that affect their reliability in keeping products on specification. The goal is to gather sufficient operating data to allow for a good correlation of operating practices with operating costs and amine unit reliability. Data from this follow-up survey will also be used to update and expand the amine *Good Practices Manual*.

The updated survey questionnaire is scheduled to be introduced and distributed to interested parties at the ABPG Amine Symposium in Dallas, Texas, on 2–3 October 1995. Those interested in submitting their amine unit(s) operating data to be included in the current survey database and participate in the updated survey may contact Mr Bruce Scott, BSI, 182 Irwin Street, San Rafael, CA 94901, USA. Tel and fax: +1 415-485 5626. Participants in the survey receive a copy of the complete database with their amine unit(s) identified by a code letter(s).

As with the original 1994 survey, the updated survey data will be completely confidential. Only those who participate in the survey will have access to the complete database resulting from it, with all participants identified by a code. The activities of the ABPG are a non-commercial, not-for-profit effort to improve the operation of amine units throughout the industry. □

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