STRATEGIES FOR SHORT-TERM H_2S REMOVAL

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ABSTRACT

In gas plants, production fields, and refineries it is sometimes required to implement a temporary H_2S-removal process on a gas stream. Unexpected compositions of newly produced gas streams and process unit shutdowns and turnarounds are two examples of situations that may demand short-term H_2S removal capabilities. Many technologies may be employed for short-term H_2S removal, and the most economical technology for short-term use may be different from the preferred technology for long-term use. The practical and economic issues for short-term use of a variety of technologies, including solid and liquid scavengers, caustic, flaring, reinjection, and regenerable technologies are considered and compared. Depending on the length of the short-term application, the most economical and effective approach may be one that would never be economical for a continuous, long-term use. Some examples are considered for both upstream oil and gas production and downstream oil refining that are based on actual projects in which Trimeric has been involved. The examples illustrate the comparison and selection process, and the technologies that are considered.

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Introduction

There is a wide variety of technology that can be used for removing H_2S from gas streams, and the general types of technologies typically applied for certain situations are well documented (1,2). Most discussions of the technical and economic feasibility of H_2S-removal methods are focused on permanent installations where capital and operating costs are balanced over a long project lifetime. Situations exist in which the removal of H_2S from gases must be implemented on a short-term basis, and criteria for the selection of technologies for the use in short-term applications are not as well established.

The need for the removal of H_2S on a short-term basis may be caused by a variety of situations in different industries. In refineries, turnarounds of units may lead to the lack of availability of an amine and/or Claus unit for weeks at a time while other parts of the refinery are still operating and producing gases containing H_2S. In oil and gas production, short-term H_2S removal may be required in many situations, including turnarounds of gas treating units, the unexpected presence of more H_2S than planned when a gas stream is first produced, the production of sour gas during well testing, and the need to implement an H_2S removal technology while a permanent solution is being designed, installed, and/or permitted. In oil and gas production, there is probably more variability in the time frame in which a short H_2S removal solution may be needed, from days to months.

The amount of time for which a short-term H_2S removal solution is required is an important variable, along with the amount of H_2S that must be removed and the type of gas from which the H_2S must be removed (e.g., amine acid gas, fuel gas, natural gas, or flare gas). This paper discusses the types of technologies that might be applied for short-term H_2S removal and the economic parameters that are important to consider. A couple of examples from refining and gas processing are also provided.

H_2S Removal Technologies for Short-Term Application

Although some equipment is designed specifically to address short-term H_2S removal applications and often offered by vendors on a lease basis, there is no technology or chemistry that is specifically targeted to this need. Technologies that are most often applied permanently to the removal of smaller amounts of H_2S may be more competitive for the removal of larger amounts of H_2S in short-term service. In general, those with a relatively low capital cost, small footprint, simple operation and control, but higher operating cost, are often advantageous. Two other factors are often important when considering short-term H_2S removal: quick availability of equipment and the potential to rent the equipment.

For permanent applications there are three general classes of technologies most often applied to H_2S removal, and the ranges – usually described in terms of LTPD of sulfur to be removed – at which these technologies are applied are well documented (1). Disposable scavengers are most often applied for cases in which less than a few hundred pounds per day of sulfur is to be removed. The amine/Claus combination is typically applied for cases when there is at least 20 LTPD of sulfur to be removed. And, liquid redox technologies and some others are often applied in the range of sulfur removal between scavengers and amine/Claus. Not all technologies and situations comply with these ranges; for example, caustic scrubbing for H_2S removal– which can be classified as a scavenger – is often applied for cases well above the scavenger range because of the relatively low cost of caustic and the potential to sell the spent caustic product, e.g., as sodium hydrosulfide (NaHS) (2).

The nature of a short-term application can result in the consideration of technologies that might not normally be considered. The following sections briefly describe the technologies that might be considered. Limited details are provided since many other papers describe the various technologies in detail; this paper focuses on the utility of the technology for short-term use. Technologies that are not suited to short-term, temporary applications (e.g., Claus) are ignored.

Scavengers

H_2S scavengers include a variety of materials that share a common trait: they are used to remove H_2S from a gas and are not regenerated; typically an irreversible reaction occurs in (or on) the scavenger, and the scavenger material is slowly expended over time and eventually needs to be removed and replaced with fresh materials. Scavengers can be solid or liquid materials. The most common solid scavengers use oxides of iron (or other metals) to react with H_2S to metal sulfides. Liquid scavengers typically use an acid-base reaction to covert the H_2S to a soluble sulfide salt, an oxidation reaction to convert the H_2S to a soluble sulfur oxyanion salt, or some other reaction. Scavenging technologies were reviewed in detail in a LRGCC fundamentals paper (2).

Scavengers, particularly of the solid form, can be implemented quickly, have a low capital cost, low complexity, and the vessels can often be rented. Most common solid H_2S scavengers are iron oxide, often supported on an inert substrate; for good utilization of the reactant, it is usually required that the feed gas contains some water vapor. Mixed metal oxide scavengers are also available, and have the capability of operating efficiently on dry gas, achieving extremely low H_2S levels, and achieving better removal of some organic sulfur species (e.g., mercaptans); mixed metal oxides are usually more expensive than iron oxide products.

Solid scavengers are typically implemented as a fixed-bed in a vertical (downflow) pressure vessel. Water is produced in the reaction and may need to be drained. Two or more vessels may be used in order to assure continuous availability and sufficient H_2S removal. The vessels must be designed to allow for ease of unloading of spent material and loading of fresh material. Simple box designs are also available for low pressure and venting applications.

The most common liquid scavengers are triazines and alkali materials such as caustic (NaOH or KOH solution), although other generic and proprietary liquid formulations are used. Sodium hydroxide reacts with H_2S to form sodium sulfide and bisulfide. Sometimes the spent caustic can be disposed of easily, but it might be necessary to oxidize the sodium sulfide to sodium sulfate using bleach or hydrogen peroxide prior to disposal, in some cases. Various types of equipment are used to implement liquid scavengers, including sparged towers, venturis, and recirculated spray, packed, and tray towers. For cases when the sour gas is being transported over a significant distance, triazine is often directly injected into pipelines, and the spent triazine recovered downstream in a separator. Simple sparged tower and recirculating scrubber skids can often be rented. One concern is that triazine has biocidal properties, so disposal, e.g., to a refinery wastewater treatment plant, must be considered carefully.

The simplest and lowest capital cost implementation of a scavenger is typically direct-injection triazine for cases where an existing sufficient run of pipe exists to achieve the necessary gas-liquid contacting (3). Sparged tower liquid scavenger and fixed-bed solid scavengers are other simple, low-capital-cost options.

Flaring or Incineration

One of the more obvious short-term ways of dealing with an H_2S-containing gas is to burn the stream. Historically, flaring of gas streams would be done when necessary since it converts H_2S to SO_2. The heat generated in burning serves to lift and distribute the burned gas high into the air, and SO_2 is considered by many to be less immediately hazardous than H_2S (although that is debatable). Flaring and other incineration methods are typically limited by environmental permits, and the capability of short-term disposal of an H_2S-containing gas by this method is limited to cases were permit limits will not be exceeded. Flaring or incineration would be the low-cost option to deal with an H_2S-containing gas for the short term, and would typically be the preferred option when allowed by permit (typically less than 162 ppmv H_2S), unless burning the gas stream is not desired for other reasons.

Incineration of an H_2S-containing stream followed by scrubbing of the SO_2 from the combustion products using caustic – sometimes referred to as “burn and scrub” – is another option for handling H_2S-containing streams for the short term. This option would only be applicable for cases where it is acceptable to burn the entire gas stream, rather than recover it, and SO_2 emissions must be maintained below a certain level. Burn and scrub may not necessarily be a viable short-term H_2S removal option because the necessary equipment may not be commonly available quickly and/or on a rental basis.

Liquid Redox Sulfur Recovery (LRSR)

H_2S removal from gases using iron redox chemistry is well known and widely practiced in industry. In addition to upstream oil and gas applications, several US refineries operate these processes, although none are known to be treating flare gas streams.

Liquid redox processes use a chemical (usually chelated iron, but vanadium is also used) in aqueous solution to absorb H_2S from gases, converting it directly to elemental sulfur (4). The chemical is regenerated to its reactive state using oxygen (air). The elemental sulfur must also be filtered from the liquid, and disposed of. LRSR processes are often used for permanent H_2S removal applications, above the economic feasibility limit of scavengers, but below the economic feasibility limit (in terms of the H_2S removal capacity) usually associated with amine+Claus units.

Historically, liquid redox would not be suited for short-term, temporary H_2S removal applications because such plants tend to be permanent installations and usually too high in capital cost to consider as a short-term backup option. However, recently some vendors have been developing versions of LRSR intended to be portable and could therefore serve as a short-term H_2S removal option. Although LRSR is usually considered applicable for gas streams containing up to about 20 LTPD sulfur, portable versions of the technology will likely have a smaller maximum unit size.

Amine Combinations

Amine units are a conventional, regenerable process often used to remove H_2S from bulk gas streams (e.g., natural gas, fuel gases), and as such are usually combined with another technology, such as Claus, to deal with the H_2S-containing acid gas produced by the amine unit. In addition to Claus, amine acid gases might be disposed of in other ways, including flaring, LRSR, burn and scrub, and subsurface injection (5).

In subsurface injection (also called "acid gas injection", or AGI), the acid gas (H_2S and CO_2) from the amine unit is compressed and sometimes dehydrated prior to injection into a reservoir, thereby eliminating emissions to the atmosphere. Subsurface injection requires that a suitable reservoir be available and many environmental and safety regulations often need to be met to make this option feasible.

Some vendors offer skidded amine units on a rental basis, and units as large as a few hundred gpm may be available. For the temporary treatment of a sour gas, an amine unit is (for most cases) only a partial solution: another step / process is generally required to deal with the H_2S-containing acid gas. This paper, therefore, only considers amine units in combination with other technologies.

Hypothetical Example of Short-Term H_2S Treating: Refinery Turnaround (TAR)

Short-term H_2S treating is sometimes necessary during outages and turnarounds at refineries. In this hypothetical example, a refinery that normally recovered flare gas in a flare gas recovery (FGR) system is facing a TAR. FGR systems at refineries typically compress low-pressure flare gas so that the gas can be routed to other refinery systems, where it is recovered as fuel gas. As a result of the TAR, the hypothetical refinery has about 2-4.5 MMscfd of gas that has to be treated for H_2S removal prior to flaring, in order to meet potential regulatory requirements during the TAR.

Four different cases were developed for this hypothetical case that represent the possible ranges in flow rate and composition of the flare gas (see Table 1). The H_2S content of the flare gas was assumed to be 0.55 to 7.7 mol%. The design basis was assumed to be to remove the H_2S to 80 ppmv or less, which is about half of the typical US regulatory requirement of 162 ppmv. An important aspect of this evaluation is that the treating period was assumed to be only about 50 days every several years for a TAR event. The resulting sulfur tonnages varied from 0.4 to 13.1 LTPD, while gas is flowing.

Table 1 – Flare Gas Design Basis

Parameter	Units	Case I	Case II	Case III	Case IV
Gas flow rate	MMscfd	2	2	4.5	4.5
H_2S	mol%	0.55	7.7	0.55	7.7
CO_2	mol%	0.2	0.6	0.2	0.6
NH_3	mol%	0.2	0.2	0.2	0.2
H_2	mol%	74.6	24.5	74.6	24.5
O_2	mol%	0.4	2.0	0.4	2.0
C1+	mol%	19.6	46.1	19.6	46.1
Other	mol%	4.6	19.1	4.6	19.1
Water	mol%	saturated			
Total (dry)	mol%	100	100	100	100
Temperature	F	135	135	135	135
Pressure	psig	13.5	13.5	13.5	13.5
Sulfur content	LTPD	0.41	5.8	0.93	13.1
Total sulfur to remove (~50 days)	LT	22	307	49	691

The options considered for the removal of H_2S from the flare gas stream are shown in Table 2. Scavenger technologies would not usually be considered at sulfur loads above roughly a few hundred pounds per day, but these types of technologies are viable because this is a short-term application (~50-day event every several years). Both rental and permanent systems were considered, although it was considered likely that a refinery would prefer rental systems, if they are available, because of typically limited lead-up time to TARs and desire to avoid purchasing permanent systems that might only be used every several years.

Table 2 – H_2S Removal Options Considered

No.	Technology	Type	Evaluated or Eliminated
1A	Amine Treating	Permanent	Evaluated
1B		Rental	Evaluated
2A	Caustic Scrubbing	Permanent	Evaluated
2B		Rental	Evaluated
3	Solid Scavengers	Rental	Evaluated
4	Liquid Triazine Scavenger	Rental	Evaluated
5	Bleach Scrubbing	Permanent	Eliminated – high chemical costs compared to caustic
6	Burn/Scrub	Permanent	Eliminated – High mechanical complexity and high chemical costs compared to caustic
7	LRSR Processes	Permanent	Eliminated – high capital expenses, mechanical complexity, and long lead times not suited to this particular short-duration H_2S treating
8	Ammonia Scrubbing	Permanent	Eliminated – No savings over amine treating and potential ammonia emissions

Various types of rental equipment are available for short-term removal of H_2S from gases. Many of these types of H_2S removal rental processes use caustic scrubbing or other liquid, or solid scavenger to remove low levels of H_2S, and are usually sized for relatively small removal rates (typically less than 0.1 LTPD). Multiple rental units could be used for Cases I and III (0.4 and 0.9 LTPD, respectively). However, use of these small-scale rental units would likely be unrealistic for Cases II and IV (5.8 and 13.1 LTPD, respectively).

Some H_2S removal processes were considered for permanent installation, rental, or both, while others were eliminated from further evaluation due to technical and operational concerns as indicated in the table. The economics of the evaluated technologies were estimated from combinations of vendor input and, for capital costs, cost estimating software (Aspen Capital Cost Estimator). The costs presented in this paper are considered to be 'screening level', and the evaluations were taken only to the level of detail necessary to allow identification of the most economical options. Utility capital costs and staffing costs were not included.

The options considered in detail for short-term H_2S removal are briefly described in the following sections.

Option 1A: Amine Treating Flare Gas, Permanent System

It was assumed that an existing amine system at the refinery had enough excess regeneration capacity such that it could provide lean amine to a new contactor to be used to remove H_2S from the flare gas stream during a TAR. This option requires the purchase and installation of a new amine contactor to sweeten the flare gas. The new contactor would have to operate at the FGR pressure (perhaps 13-14 psig), rather than the higher pressures typical of amine contactors, so making the required H_2S removal specification at the lower pressure could be difficult. The sweetened gas would then be flared.

A schematic of this concept is shown in Figure 1. The basis for the amine treating option is that the lean amine can be provided to the new contactor with sufficiently low loading (on the order of 0.0075 mol acid gas/mole DEA amine) so that the new contactor can achieve the 80 ppmv H_2S treat (see Figure 2). Some refinery amine units may not achieve lean loadings this low, because it is not typically required during normal operation with the higher pressure contactors. If it turned out that a regeneration unit could not achieve sufficiently low lean loadings, then other options (i.e., modifying operating procedures, cooling the lean amine, adding a small stripper, etc.) would be required, which would make this option more expensive.

Option 1B: Amine Treating Flare Gas, Rental System

For Option 1A, it is assumed that the only major purchased equipment required to implement amine treating of the flare gas is a contactor column and associated pumps and controls. In this Option 1B, Trimeric inquired about using a contactor, pump, and controls on a rental basis with regeneration still performed by an existing amine unit at the refinery. Some vendors identified potential equipment that could be used, but the sizing of the contactors would need to be evaluated thoroughly for actual use. Vendors also offer complete rental amine units with regeneration equipment

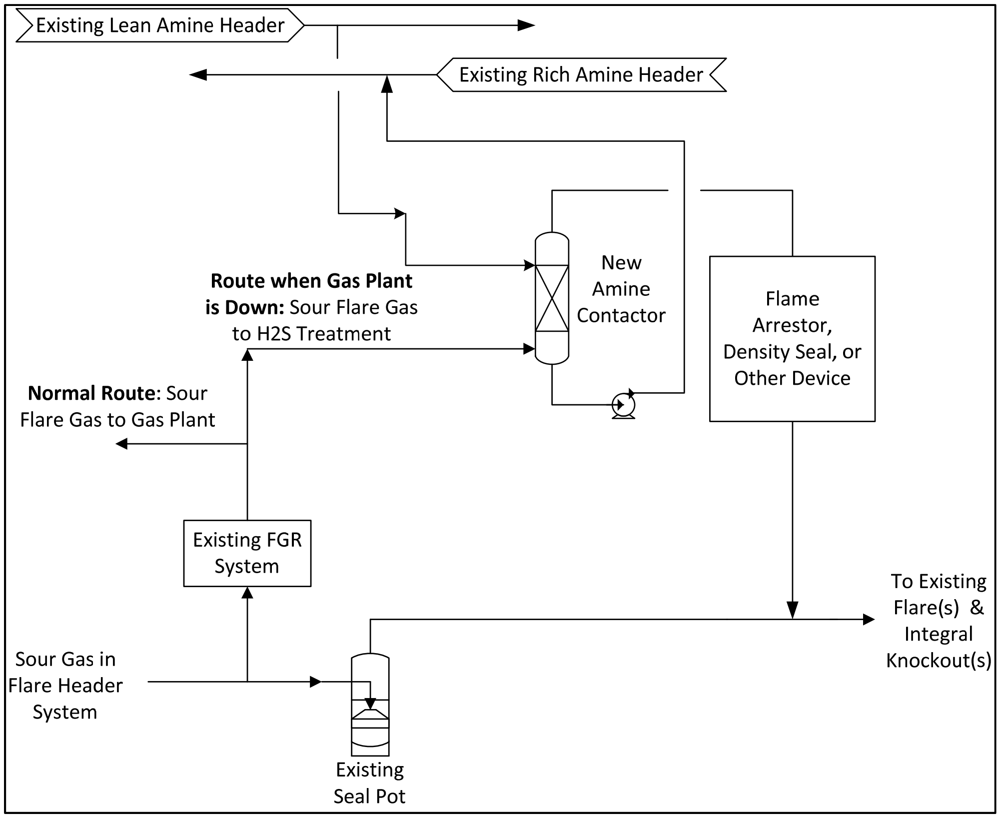

Figure 1 – Example of Treating with a New Amine Contactor (Option 1A and 1B)

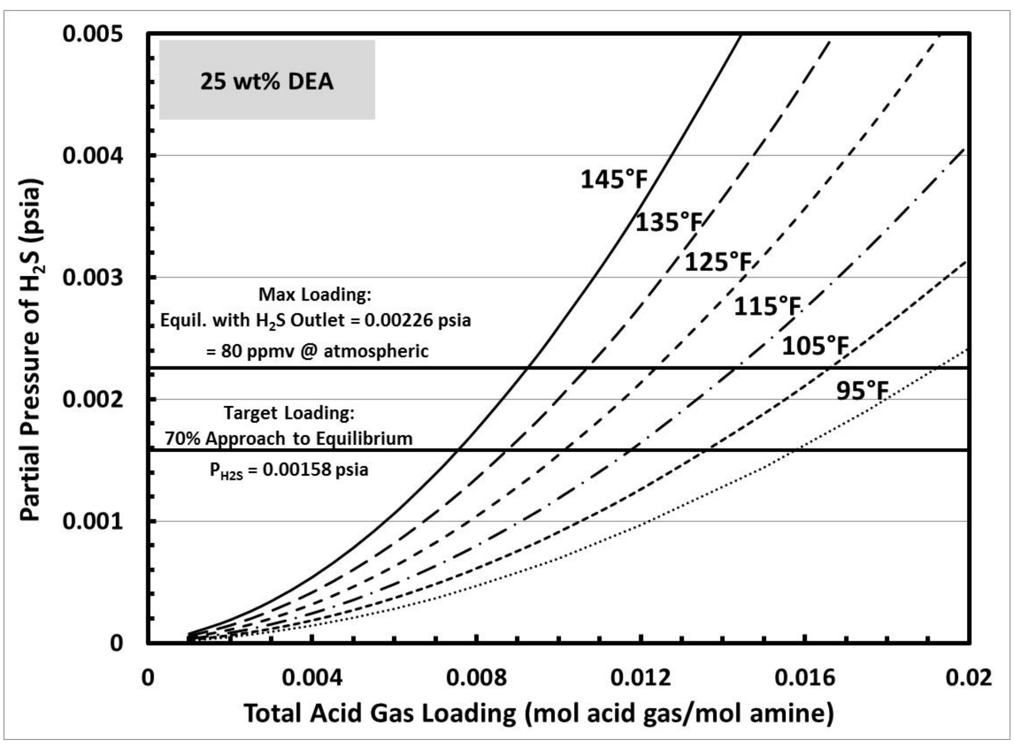

Figure 2 – Lean Amine Loading Requirement

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Options 2A and 2B: Caustic Scrubbing

Caustic (NaOH solution in water) scrubbing is a common scavenging method for the removal of H_2S from gases, particularly for cases when the composition of CO_2 is much lower than that of H_2S. Various technologies are used to implement caustic scrubbing for the removal of H_2S from gases. Since, in this hypothetical example, H_2S treatment is only required for ~2 months every several years, a simple caustic scrubber system without extensive controls could be used for a permanent installation. Figure 3 shows that the basic equipment consists of a packed tower with recirculation, feed, and spent caustic pumps. It was assumed that existing storage tanks at the refinery would be used.

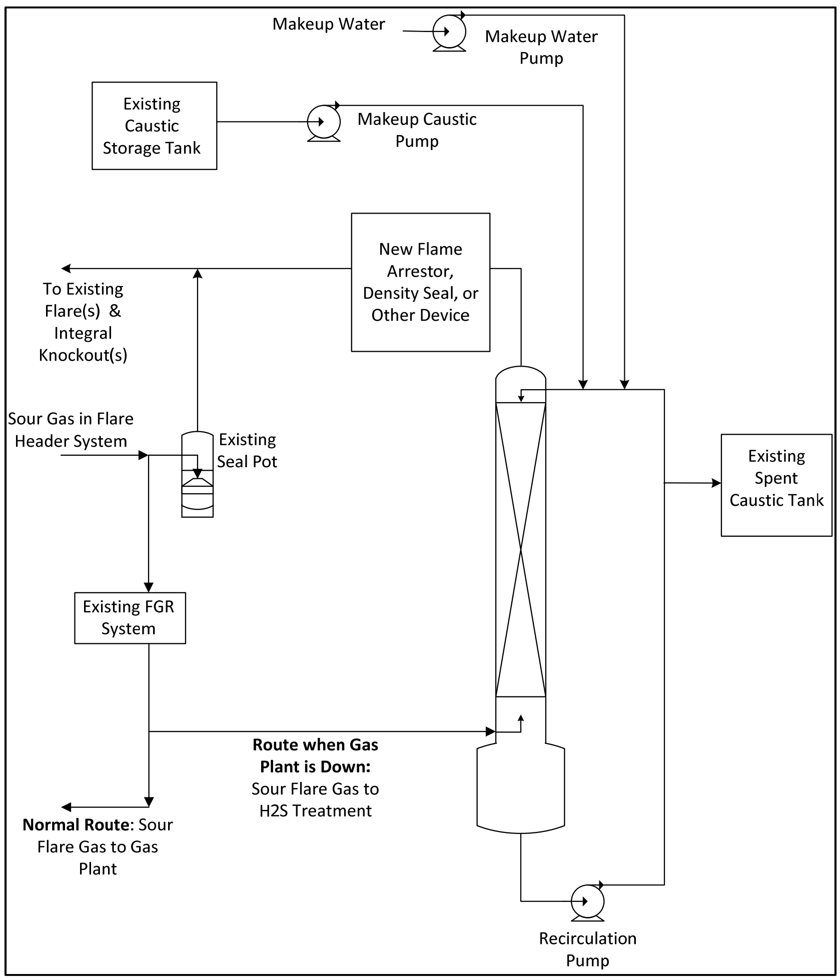

Figure 3 – Example Caustic Scrubber System

Caustic scrubbing requires continuous addition of caustic, soft water, and the blowdown of spent caustic (a mixture of NaHS, Na_2S, and Na_2CO_3); batch makeup and blowdown can also be done. The refinery uses 20 Baume caustic and solids precipitation is not anticipated at the normal operating conditions of the scrubber (140-150ºF) or storage tank.

Option 3: Solid Scavengers

Figure 4 shows a typical fixed bed configuration for solid scavengers; two beds, either on-line and off-line or lead-lag, are typically used. Given the fact that the system is simple – consisting primarily of large, low-pressure vessels – and easy to obtain from vendor on a rental basis, it was assumed in this analysis that rental units would be used.

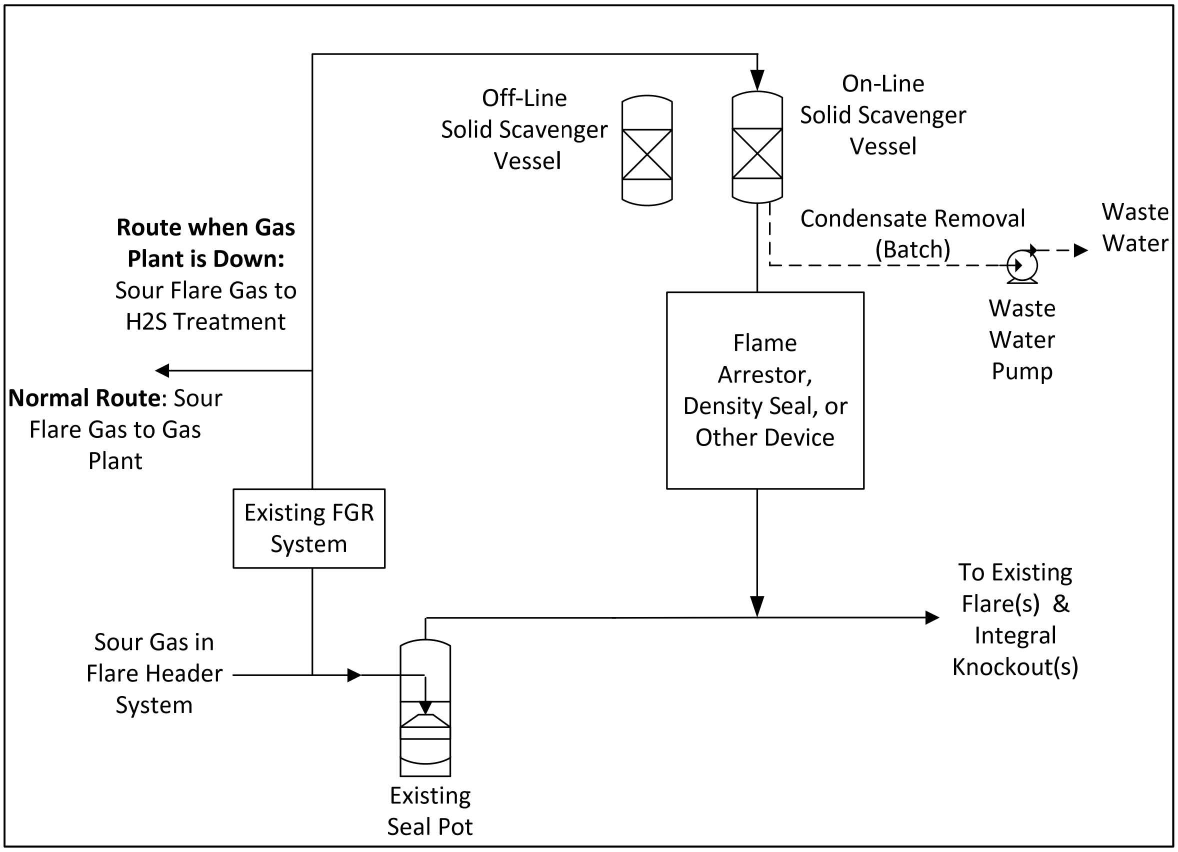

Figure 4 – Example Solid Scavenger Flowsheet

Option 4: Triazine Liquid Scavenger

For this application, triazine would be implemented as a gas-liquid contacting vessel (see Figure 5) similar to caustic scrubbers, and it is assumed that the contacting system would be rented. Direct pipeline injection was also considered, but it was assumed that there was not a pipe run in this system that would accommodate that particular low-capital cost triazine implementation. Issues with triazine disposal (biocide) and impacts on wastewater systems are also typically a concern.

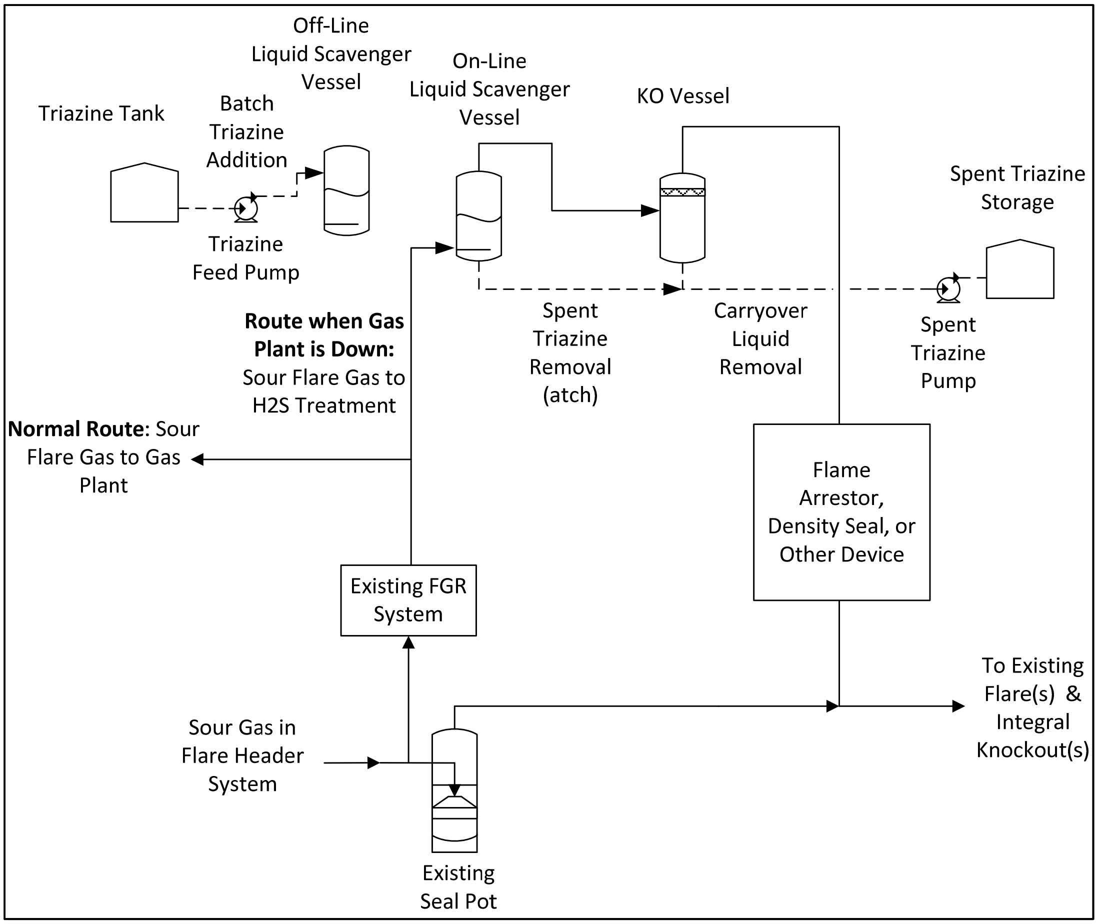

Figure 5 – Example Contactor Vessel Triazine Scrubbing

Options 5-8 in Table 2 – bleach scrubbing, burn/scrub, liquid redox processes, and ammonia scrubbing – are technologies that were, after brief consideration, eliminated from detailed consideration in this hypothetical example due to high costs, mechanical complexity, and/or potential environmental issues as briefly described in the following sections.

Option 5: Bleach Scrubbing

Bleach scrubbing requires the use of both caustic (2:1 $NaOH:H_2S$) and bleach (4:1 $NaOCl:H_2S$), and there could also potentially be issues with bleach side reactions and vent emissions. The use of bleach to oxidize the absorbed H_2S usually results in the liquid blowdown being easier to dispose of. However, bleach is relatively expensive, and it was determined that, given the complexity of the process and the capital and operating costs, bleach scrubbing was very unlikely to be competitive in this hypothetical example application.

Option 6: Burn/Scrub

The capital cost for the process is substantial and there is significant increased mechanical complexity due to the number of different equipment processes for operation given that H_2S treatment is required only every several years.

Option 7: LRSR Processes

The LRSR process has high capital cost for a process that would be used very infrequently at this hypothetical refinery. Also, rental LRSR units were not believed to be available during this project but may be becoming more available for small-scale applications.

Option 8: Ammonia Scrubbing

Ammonia solution can be used to scrub H_2S to make ammonium sulfide or bisulfide. The technology was not viewed as being any more economical than amine treating and there were also concerns with NH_3 emissions that could impact downstream equipment should carryover occur.

Economic Evaluation of Permanently Installed H_2S Removal Systems

Figure 6 shows the economics for the most promising permanent technologies, which includes a new amine contactor, caustic scrubbing, and solid scavengers. The table shows the operating expenses (total for a single TAR), the estimated installed capital cost, and total cost (single-TAR operating costs plus total capital cost) for the first event. The operating expenses include items such as power, makeup chemicals, waste disposal, and labor. The capital costs represent the installed costs of major equipment systems, based on vendor budgetary estimates and the Aspen capital cost estimator. Installation factors were based on engineering experience. The average cost from multiple vendors or variations in equipment configuration were used.

The most economic permanent H_2S removal method for all four cases considered was Option 1A (amine treating via a new contactor that tied into the existing amine unit that was assumed to be available at the hypothetical refinery, see Figure 1). The new amine contactor concept is the most economic ($1,200K to $1,800K, total cost) because it requires no significant additional feed chemicals or disposal of waste products since the amine from the existing system at the plant is assumed to be used. It also has a relatively low capital cost since only the purchase of an amine contactor and return pump are required; amine regeneration equipment is not needed since the rich amine would be sent back to an existing amine system. The contactors must be rather tall (50-60 feet S/S) due to the low H_2S partial pressures of the feed gas and the need to treat the gas to 80 ppmv H_2S.

Caustic scrubbing is the second most economic process ($1,250K to $5,300K, total cost). Its operating expenses are higher than Option 1A because caustic needs to be purchased and disposed of. However, operators are often familiar with caustic scrubber operations and maintenance since other caustic units are often used at refineries.

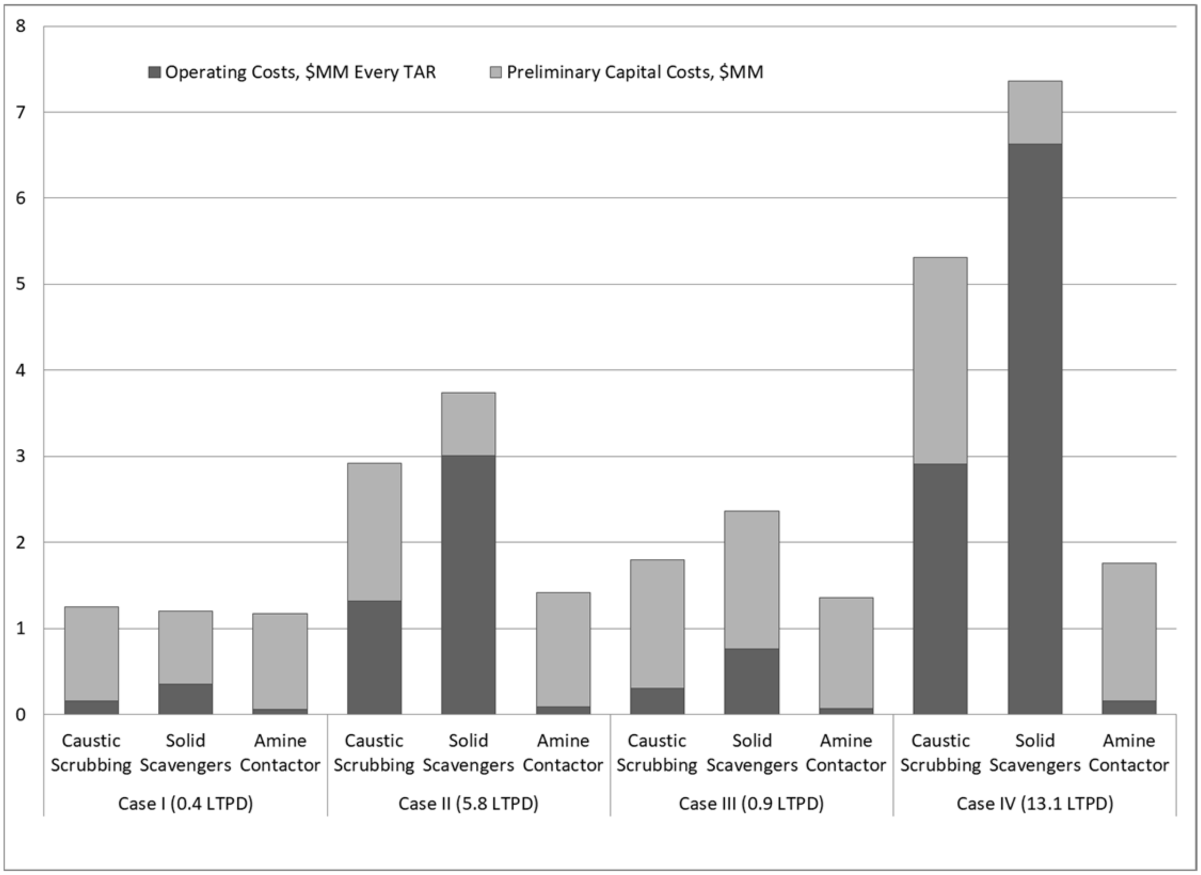

Figure 6 – Economic Summary of H_2S Treating for Permanent Installation (CAPEX + First TAR Event)

Solid scavenging with media is the third most economic option ($1,200K to $7,350K, total cost). This could be a new, albeit simple, process for a refinery. Although the equipment is relatively simple and requires little attention to operate, changeouts of the solid media can be difficult and time consuming, especially for the large H_2S removal tonnage cases. The solid media is also costly per batch for large tonnage removal cases. Finally, there can be concern with the potential for overheating the media, especially with Cases II and IV, and heat mitigation would likely need to be incorporated into the design for these cases. For these reasons, solid scavengers were the least favored of the three treating technologies for Cases II and IV, mostly due to the cost of the scavenger chemical.

In general, the balance of capital and operating expenses is very different for the treatment options. The high cost of the solid scavenger adsorbent makes this technology option very operating cost intensive due to the need to dispose of spent media and replace it with fresh material, especially as the sulfur tonnage removal increases. The equipment for caustic scrubbing is more complex and, although spent caustic must also be disposed of and has to be replaced, the chemical usage and cost is less than scavengers, making it a technology option with costs that are more evenly balanced between capital and operating expenses. The new amine contactor option is predominantly capital intensive since the regeneration component is assumed to be tied into existing processes at the facility and thus had no, or very low operating costs. If a complete amine system were required, than the capital and operating expenses may be more balanced due to the additional regeneration equipment and energy demands. Overall, the economics for the higher sulfur tonnage cases (Case II and IV) are driven by operating expenses (replacement chemicals) and the smaller tonnage cases (Case I and III) are capital dominated.

Economic Evaluation of Rental Equipment Options

Figure 7 shows a summary of the economics for the removal of H_2S from flare gas during a TAR using primarily rental process equipment. When cost data for the same process system was available from more than one vendor, average values were used. Rental equipment was found to be readily available for caustic scrubbers, liquid triazine scrubbers, solid scavengers, and amine contactors. Rental equipment for the caustic, liquid triazine, and solid scavengers is typically designed for low tonnage (<0.1 LTPD) applications. Although the sulfur tonnages for Case I and Case III (0.4 and 0.9 LTPD, respectively) exceed the typical design range of this rental equipment, the rental equipment was considered for these two cases. Rental equipment providers declined to offer options for Case II and IV since the chemical consumption, equipment requirements, and cost would clearly be economically uncompetitive. Rental amine contactors could, however, be used for all four of the cases.

Operating costs included in this analysis are feed chemicals, waste disposal, and labor as well as the rental expenses for a single TAR event. An installation cost of $394K was assumed for all of the rental units (the installation cost would probably be lower for subsequent TAR events after the first one since pipe runs, etc. presumably would be left in place between shutdowns).

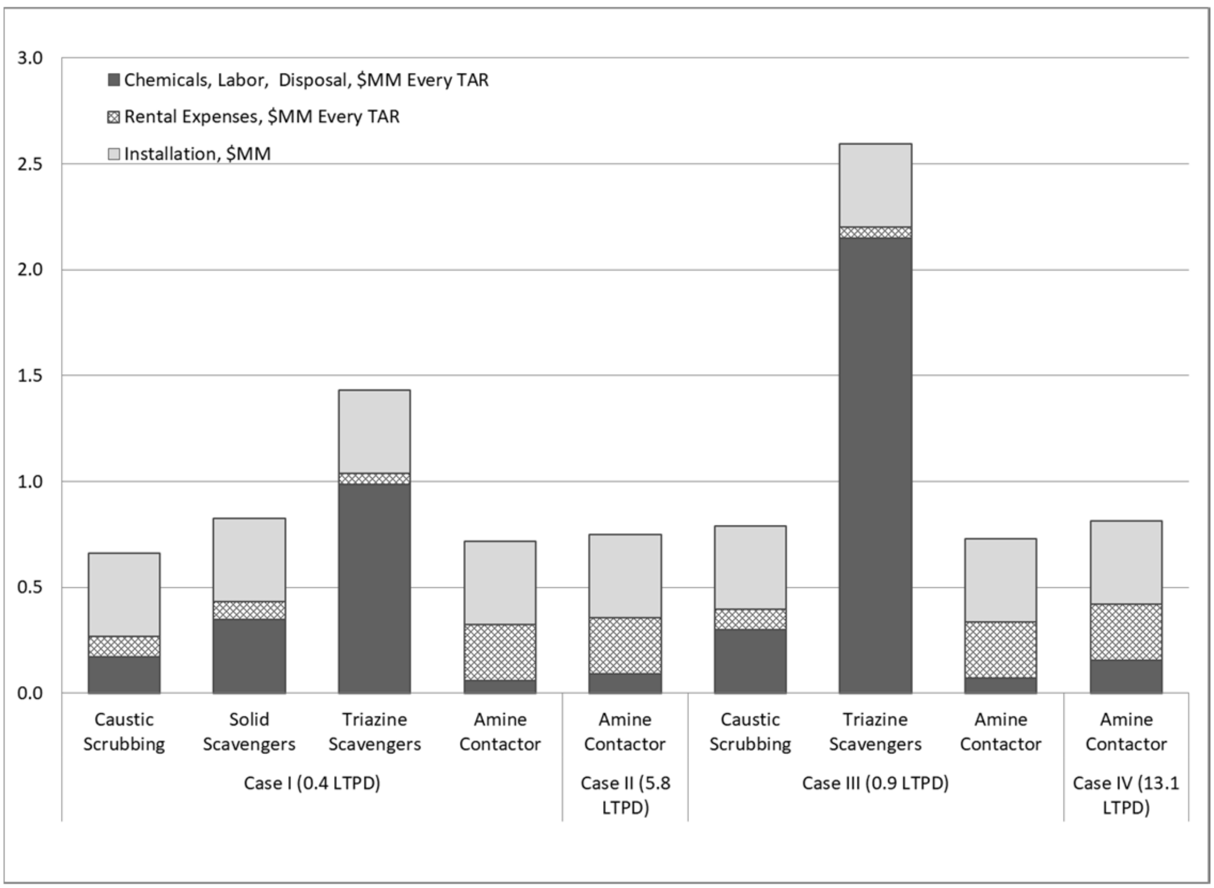

Figure 7 – Economic Summary of H_2S Treating for Rental Equipment (First TAR Event)

The economics show that solid scavengers have a cost of \$825K for Case I. One solid scavenger provider offers rental equipment and other media providers were willing to locate fabricators or partners that might consider leasing vessels.

The total cost for amine treating using a rental contactor ranged from \$725K to \$825K per TAR for all of the cases based on the approximate rental terms from one vendor. However, vetting the amine equipment for this unusual low-pressure application may be difficult. Since most amine designs in refineries are probably for higher pressure (100+ psig), the H_2S removal performance would need to be evaluated in detail to ensure that the target of 80 ppmv outlet H_2S can be achieved at the low operating pressure with the existing trays or packing present in a rental contactor. The design of the contactor itself (nozzle size, diameter, etc.) would also need to be evaluated. The bulk of the operating expenses are labor since no significant chemicals and disposal are required.

The total cost for caustic scrubbing using rental equipment ranged from \$665K to \$800K per TAR for Cases I and III. Some of the caustic gets consumed by the CO_2 in the flare gas. Rental scrubbers come in some different configurations (e.g., sparged, packed, etc.). Storage tanks for the feed and spent caustic are not typically provided; but existing tankage at a refinery might could be used or temporary tanks brought in.

Mobile rental equipment is available for liquid triazine treating; however, the chemical costs were prohibitive at these tonnages (\$1.0MM to \$19MM), and this option was not pursued further for this hypothetical example.

Hypothetical Refinery TAR Example Summary

In this hypothetical refinery example, the need for H_2S removal from a flare gas stream was limited to an infrequent and relatively short duration of time (~50 days, every several years) during scheduled TARs. Although the sulfur tonnage was outside the normal range for which some technologies (e.g., solid / liquid scavengers) would normally be considered economical for long-term use, the infrequent treating need allowed these processes to be considered.

Other situational factors in this hypothetical refinery example were important in selecting the short-term H_2S treating technology. Because the TAR was assumed to be near-term, rental technology that could be implemented more quickly with less stringent installation requirements than with permanent equipment was assumed to be desired. Rental caustic scrubbing systems seem to be more common than with other rental scavengers and amine equipment, and some caustic scrubbing vendors also offer on-site operational support for TARs. While the rental amine contactor approach was also economical, most rental equipment was designed for 300+ psig treatment, and the contactors might not be designed properly for this low pressure application. Solid scavengers aren't commonly used at refineries, and solid waste disposal may be a concern. Caustic scrubbing had reasonable total costs for the first TAR event, and so is probably the best choice for this example, especially if a rental unit can be obtained that is rated for the pressure of the flare gas stream.

Other Example of Short-Term H_2S Treating in Refineries: Sulfur Plants

The sulfur plant is another area within the refinery where short-term H_2S removal is applied. Examples of applications of short-term H_2S treatment related to the sulfur plant in refineries include (but are not limited to) the following:

- Back-up service for Claus Plant outages;
- Back-up service for the tail gas treating unit;
- Back-up service for sulfur pit, truck, and loading vapor management; and
- Interim service with new equipment installation.

Caustic scrubbers are often used in backup service in the sulfur plant (6). The caustic scrubbers would need to be designed to handle the intermittent short-term use and specific operating conditions of the SRU. Some design elements to consider for caustic scrubbers in these short-term applications are: i) using minimal instrumentation with simple designs to reduce failure points in the system; ii) implementing continuous circulation of caustic solution to wet the packing and column internals in between use; iii) sparing pumps; iv) installing a caustic cooler / heat exchanger to maintain solution temperature and prevent solution dehydration with large H_2S loads; v) considering other contaminants (such as elemental sulfur) in the operation of the scrubber (7); and vi) implementing regular inspection of instrumentation for functionality, plugging, corrosion, etc.

Example of Short-Term H_2S Treating: Gas Processing

Treating for H_2S removal in upstream gas processing facilities could have very different economic drivers than in refinery settings. The high pace of drilling using fracking technology has led to many new wells coming on-stream in a short period of time. Much of the new production is justified solely by the oil production, and the associated gas must be processed to allow the oil to flow. The composition of the associated gas from this new production is often not predictable; for example, Trimeric has worked on projects to remove very high concentrations of H_2S (up to 3 mole%) for producers who have nearby wells that are sweet.

Treatment of co-produced gases may result in the production of an acid gas; for cases where the flow rate of acid gas to be disposed is very high, injection of the stream into a disposal well is often the option preferred by many producers. However, it is not always possible to inject acid gas streams, and some acid gas streams may not be large enough to merit the high capital cost of acid gas injection (AGI). There often is a mismatch between the lead time for getting an AGI well permitted and the required equipment purchased and installed versus the required on-stream time for treating the associated gas production. The unpredictability and variability of the H_2S concentration as wells go on and offline add risk to implementing traditional H_2S conversion processes like Claus and LRSR. The unique combination of i) schedule constraints and ii) economic considerations that are only secondarily tied to the value of the gas in some cases can lead to the selection of non-typical H_2S removal processes.

Consider an example case with the following characteristics:

Produced gas flow rate: 50 MMscfd
H_2S concentration: 1,000 ppmv
CO_2 concentration: 2 mole%
Treated Gas Specification: nmt 4 ppmv H_2S,
nmt 2 mole% CO_2

For this application, the client decided to pursue amine sweetening with AGI as the long-term solution. However, it would take 12-18 months for the AGI system to be in operation, mostly due to permitting and delivery of long lead items such as compressors; however, the gas had to be sweetened in less than 12-18 months.

Disposable scavengers typically would not be considered for traditional, permanent gas treating applications with this gas. The sulfur loading is 1.9 LTPD, which tends to make liquid redox sulfur recovery (LRSR) processes economically favorable compared to scavengers, for permanent applications. The economics of scavengers can be relatively competitive, though, if the operating lifetime is short enough so that high operating costs are offset by low capital costs. Solid scavengers can be deployed in a matter of weeks if vessels are available to meet the hydraulic and code requirements.

Figure 8 shows the cumulative cash flow (not amortized) for scavenging (conventional supported iron-oxide solid products, directly treating the sour natural gas) and amine/LRSR relative to the base-case option of amine/AGI for the example case of 50 MMscfd with 1,000 ppmv H_2S. The costs for the amine/AGI unit include capital for the base equipment (amine and compression) as well as the injection well, although expenses to locate, assess, and permit the well vary widely from location-to-location. A typical cost that includes normal effort for injection well assessment and permitting has been included. The relative costs for amine/AGI and amine/LRSR may flip in some locations. The actual capex and opex costs used for each option are based on a combination of recent vendor budgetary quotes and standard reference costs for conventional processes. Note that the cash flow for the disposable solid scavenger option does not cross the cash flow for the amine/AGI option for nearly three years of operation. Solid scavenging also has a much lower initial capex and increased flexibility compared to the amine/LRSR and amine/AGI options. Fluctuations in gas rate and H_2S concentration have much less impact on the operability of scavenger systems than on the amine systems. The bottom line is that for this 1.9 LTPD H_2S removal application, scavenging could be used for at least two years with minimal disadvantage on the gas treating economics compared to more permanent technologies. The amine/AGI and amine/LRSR still clearly have more favorable economics for long-term operation. Figure 9 shows the opex and capex contributions to the total treating unit costs with capex amortized over a 5-year period.

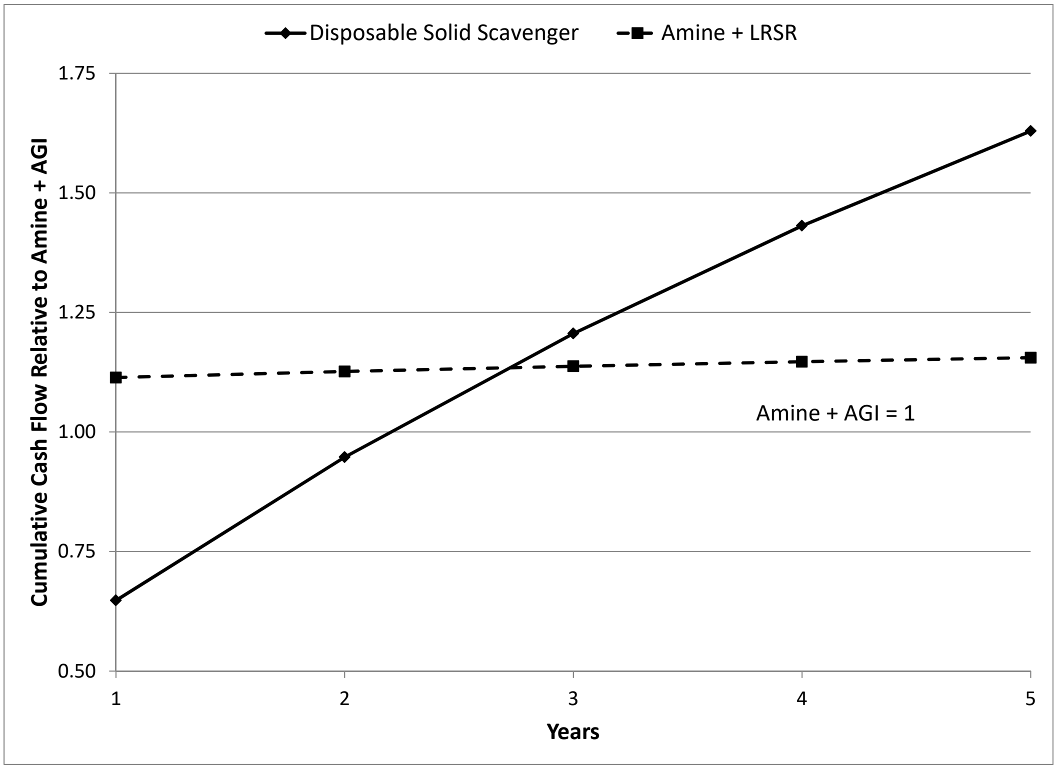

Figure 8 – Economics of Solid Scavengers and Amine/LRSR Relative to Amine/AGI (Amine/AGI = 1). Design Basis is 50 MMscfd with 1000 ppmv H_2S.

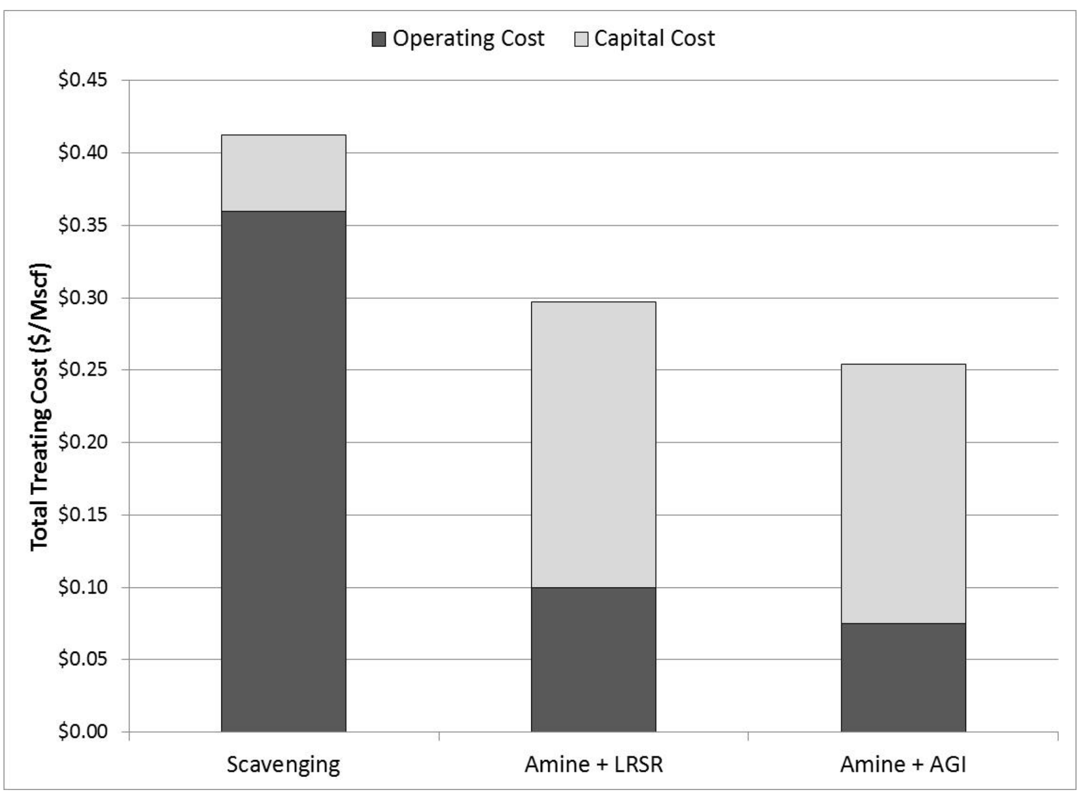

Figure 9 – Opex and Capex Contributions to Total Treating Cost. Design Basis is 50 MMscfd with 1000 ppmv H_2S.

There appears to be a need for short-term H_2S removal technologies that can be used for larger H_2S removal applications. In particular, a rapidly-deployable process with operating costs less than disposable scavenger chemicals but higher than permanent solutions (i.e., operating costs typical of LRSR) may be able to displace disposable scavengers from applications where the amount of H_2S being removed is significant. Caustic scrubbing is another technically-feasible process with costs expected to be between scavenging and amine/LRSR. The availability of rental scrubbers and nearby disposal wells would determine if caustic scrubbing is a short-term or long-term option.

Conclusions

The removal of H_2S from gas streams for short duration presents different economics than permanent installations, and often results in the selection of technologies that are associated with higher operating cost, lower capital cost, and rapid availability. The refinery example showed the details of capital and operating costs for a variety of technologies that could be employed to treat a flare gas stream for a TAR. The decision-making process included factors in addition to simple economics: for example, the availability of rental equipment appropriate to the task is also a key variable. The ready availability of one of the better options (caustic scrubbing) as a rental unit was a key factor in the analysis of the given hypothetical example, compared to some others that were as good (or better) from strictly an economic perspective. The gas treating example focused on short-term treatment of co-produced gas, where the economics necessitate short-term treatment of the gas even at relatively high cost, as better long-term treatment systems are permitted and built. An economic evaluation developed for a short-term gas treating case showed that solid scavengers are economical well above their normal application range, compared to other options. This study also highlighted the need for more rapidly deployable, short-term H_2S removal technologies that can provide operating costs less than that of conventional solid scavenger chemicals, in order to treat some of the high H_2S content gases that must be treated for short terms.

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