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Review of H_2S Abatement Methods in Geothermal Plants

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ABSTRACT

Despite having significantly lower emissions in comparison to traditional fossil fuel plants, geothermal power plant emissions can still be substantial. In particular, dissolved non-condensable gases (NCG) such as CO_2 and H_2S within geothermal fluids have led to increased interest in developing methods for decreasing these emissions through abatement systems, or potentially using these gases to generate value for use in industrial processes.

This paper discusses some of the H_2S abatement methods available to the industry, such as liquid redox methods, reinjection, Selectox, Dow-Spec RT-2, BIOX, and others. Tools for screening suitable abatement methods for geothermal fields of different non-condensable gas characteristics are presented. The paper also presents technology being researched, but not yet widely applied commercially.

The paper presents the most common abatement methods, their characteristics, advantages, and limitations. A simple decision tree is also provided as a screening tool for choosing appropriate abatement methods for different geothermal plant and geothermal steam compositions. It is a basic outline designed to provide a quick, graphical summary of the major considerations and constraints involved with choosing candidate methodologies, prior to more detailed consideration of preferred options given a plant's site-specific characteristics.

Finally, the paper discusses the legislative changes in Iceland that will lead to greater use of abatement systems for plants in that country, the screening considerations applicable to that setting, and research projects underway at the Hellisheidi field involving distillation and reinjection of CO_2 and H_2S into the geothermal reservoir.

1. INTRODUCTION

Around the world, only several countries, where stringent air quality standards have been put in place, operate hydrogen sulfide abatement systems in their geothermal power plants.

In the United States, H_2S emission rules were applied in the 1970's to achieve compliance to air quality standards, particularly in California. Japan has had a strict policy regulating odor nuisance since 1972. This law regulates emission of odor against all industries in a designated area. The first H_2S abatement system in that country began operating satisfactorily in 1998 in the Fukushima Prefecture, at the Yanaizu-Nishiyama Geothermal Power Station.

By 1980, several commercial control technologies were available for the geothermal industry, some of which are reviewed in this work. Some are still being used under certain economic and technical circumstances, others are no longer used, and others have been updated and continue being used with improvement over the years.

Sanopoulos and Karabelas (1997) published an evaluation of process alternatives for abating hydrogen sulfide from geothermal power plants. Although a very comprehensive and relatively detailed work, it lacks more current information about the experience from industry application of the methods. This paper aims to expand and bring up to date that information by shedding light on new technology and processes being developed, as well as providing feedback regarding the performance of the processes in full scale operation around the world.

The present work provides a summary of various abatement methods. All of the methods presented are capable of achieving over 90% removal of H_2S carried with the geothermal fluid. Key variables that influence capital and operating cost are identified. A tool for screening different abatement methods for different geothermal fields is presented. Finally, proposed abatement strategies at the Hellisheidi power plant, Iceland, are discussed.

2. CLASSIFICATIONS OF AVAILABLE METHODS

Stephens, et al. (1980) describe two main approaches for removing H_2S: before the steam flow reaches the turbine (upstream) and after the turbine (downstream). Sanopoulos and Karabelas (1997) further classify the different methods according to the type of flow the method has to deal with for abating H_2S. Table 1 below describes these groups, and Figure 1 illustrates the treatment location for these methods in the power plant diagram.

Table 1: General classification of methods for H2S abatement

Method	Location	Type of flow
Method A	Upstream	Geothermal steam
Method B	Downstream	NCG system exhaust
Method C	Downstream	Condensate water
Method D	Downstream	Combination of flows

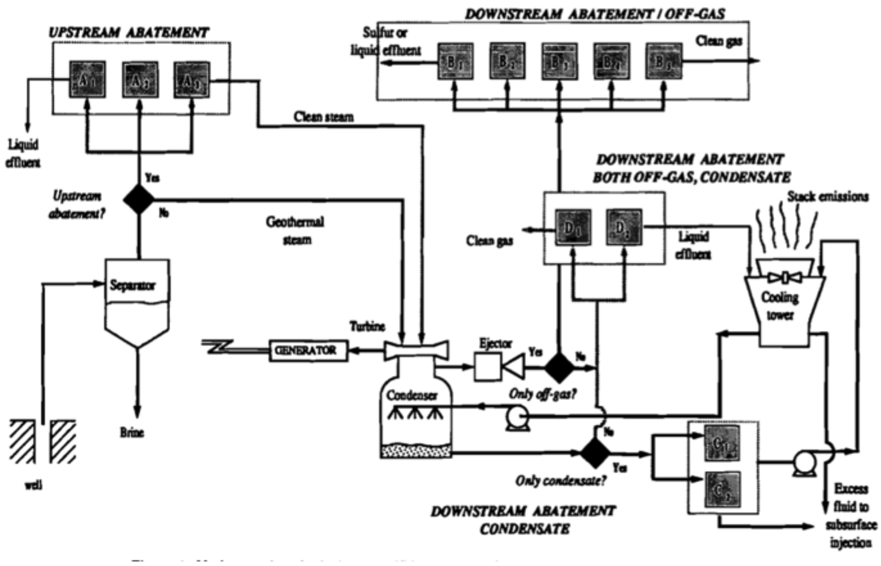

Figure 1: Classification of options for H2S abatement (Sanopoulos & Karabelas, 1997).

2.1 Methods A: Abatement from geothermal steam

Type A Methods are strategies that eliminate H_2S upstream of the plant and, as such, are concerned with the totality of the steam entering the plant. The main advantages of removing the H_2S at this point in the process is the possibility of eliminating H_2S emissions during steam stacking. At the same time, these methods protect the turbine components from corrosion and scaling due to contact with the non-condensable gases. With this reduction of non-condensable gases entering the condenser, there is a backpressure reduction during normal operation, which leads to improved power production. However, as pointed out by Sanopoulos and Karabelas (1997), there is an inherent loss of steam and its associated enthalpy from these treatments.

The methods reviewed in this category are the Copper sulfate or EIC process, and Scrubbing with an alkali.

2.1.1 Copper sulfate process

Stephens (1980) describes this process, where the steam is contacted in a scrubber with a solution of copper sulfate to produce elemental sulfur. For this process it was found that, despite being applicable for plants equipped with either surface or direct contact condensers, and with a high H_2S removal efficiency, the high capital and operating costs of this process make it an uneconomical choice.

2.1.2 Scrubbing with an alkali

According to Owen and Michels (1984), this process consists of scrubbing the geothermal steam or non-condensable gases with alkali, usually a solution of NaOH. The scrubbing with alkali process can also be installed with both type of condensers and it is not influenced by the geothermal steam composition. Its low capital and relatively high operating costs, due to large consumption of chemicals, make it more suitable for small power plants, with a short operating lifespan, or to be used sparingly, if scrubbing is to be done temporarily only during upset conditions.

2.2 Methods B: Off-gas

Type B Methods are concerned with the stream of gas exiting the condenser through a non-condensable gas removal system. These processes usually produce elemental sulfur from the H_2S content. Depending on how each particular process operates, some abatement systems may require a surface condenser, but some may still be used with a direct contact condenser. The methods reviewed in this category are Liquid redox methods, AMIS, non-condensable gas injection systems, Peabody-Xertic process, Fe-Cl method, Selectox, Biological/THIOPAQ methods, and Burner-scrubber process.

2.2.1 Liquid redox methods:

The Stretford process converts H_2S to sulfur by catalytic air oxidation. This process has proven to be very successful at the Geysers geothermal field for the past 30 years, where 15 Stretford units were installed during 1979 to 1989, and 13 are currently operating.

As reported by Farison, Benn and Berndt (2010), these units have operated very well, with minimum downtime, and have experienced few problems regarding catalyst and Stretford solution disposal.

The Unisulf process uses a solution for absorbing H_2S from gas streams, and oxidizes it to elemental sulfur. Marketed by Unocal, the process' chemistry has been modified to eliminate by-product salt formation, such as thiosulfates and sulfates. According to Dalrymple, Trofe and Evans (1989) and Gowdy, Delaney and Fenton (1988), this process offers the same efficiency of H_2S absorption as a Stretford solution, with the added benefit of a lack of solid deposition

The SulFerox process involves the usage of chelating iron compounds in a concentrated solution to oxidize the H_2S to elemental sulfur. A technical report issued by the World Environment Center (1994), discusses the use of this method in the Bureau of Land Management BLM-East and BLM-West plants at the Coso field, California. In these plants, the demisters installed in the vent stacks had to be removed because they quickly fouled with sulfur after start-up.

The LO-CAT abatement method uses an extremely dilute solution of iron chelates. The gas containing the H_2S reacts with the iron solution in an absorber to form elemental sulfur, which is removed through centrifugation. The reactions involved in this process are the same as in the SulFerox process, as pointed out by Abdel-Aal (2003). Nagl (2009) discussed the success of the LO-CAT system in the Coso geothermal field. There, it is mentioned that the three LO-CAT systems have consistently posted high efficiencies (above 99.99%) and the unit performances have stayed fairly constant.

The Hiperion process uses a chelated iron catalyst combined with naphtaquinone to remove H_2S from hydrocarbons. This system is an improvement of the Takahax process used in Japan, with faster reaction dynamics, which reduces the equipment size required. The gas/liquid contactors use beds of a patented material that is resistant to pH changes and to plugging, report Dalrymple, Trofe and Evans (1989) and Pandey and Malhotra (1999) The operating experience of this process is limited.

The most widely used liquid redox system is the LO-CAT II. This process employs a ferric catalyst to oxidize the H_2S, producing elemental sulfur and water. The World Environment Center (1994), reports that chemical losses and plugging in the water lines have not been a problem in the Navy I and Navy II units of the Coso geothermal field.

In summary, the liquid redox methods are more suited for plants that use surface condensers, and where the concentration of ammonia in the geothermal steam is low ($NH_3/H_2S < 1$). Here, these methods can achieve very high removal efficiencies of the H_2S. A high concentration of ammonia promotes partitioning of hydrogen sulfide into the condenser condensate. When the condensate is passed to the cooling tower, the hydrogen sulfide dissolved there would be emitted to the atmosphere and bypass the Method B system. Given the complexity of the majority of the processes in this category, a high capital expense is required, but they usually have a very low operating cost. For this reason, these processes are best suited for large units, with an extended operating period.

2.2.2 AMIS:

This process removes mercury and hydrogen sulfide from the gases extracted from the condenser. Baldacci (2004) describes that the abatement of hydrogen sulfide takes place in a catalytic oxidation reaction at 240 °C to produce SO_2. The AMIS process operates well with a direct contact condenser and low ammonia content in the geothermal steam. It is currently used in powerplants of smaller sizes, around 20MW, and the process has been tailored for the particular composition of the Italian geothermal resources at Lardarello.

2.2.3 Non-condensable gas injection

According to Sanopoulos and Karabelas (1997), in this process, the non-condensable gases are compressed, mixed with the brine effluent from flash separators, and reinjected underground. The relative simplicity of the process gives it low capital and operating costs, which makes it a candidate for application in both large and small geothermal plants. The power plants at the Coso geothermal field in California utilized this abatement system for nearly seven years, reports the World Environment Center (1994), but were slowly phased out in favor of other abatement technologies, due to difficulties. Problems encountered included gas breakthrough, vapor lock due to insufficient liquid for reinjection, and corrosion of the gas lines and well casing.

2.2.4 Peabody-Xertic process

This process uses a solution of citric acid to perform an oxidation reaction in the liquid phase with solid sulfur as a final product, describes Vancini (1986). The Peabody-Xertic process is only suited for plants with surface condensers, and depends on the geothermal steam having low concentration of ammonia. The high capital and operating costs of this system do not make it viable for small power plants, therefore it is only recommended for large projects, with extended operating periods, report Sanopoulos and Karabelas (1997)

2.2.5 The Fe-Cl hybrid system

The Fe-Cl hybrid system is purported to have low capital and operating costs, according to Matthíasdóttir (2006). However, the process is still in laboratory scale experimentation, and it is unknown how the system will perform in commercial applications. This method utilizes a highly acidic iron solution through which the off-gas from the condenser is bubbled. Solid sulfur precipitates with a nearly 100% elimination of H_2S at a temperature between 70 °C and 75 °C.

2.2.6 Selectox

This process has been used at the Yanaizu-Sishiyama geothermal power station in Japan, as reported by Takahashi and Kuragaki (2010). This process combines the Selectox catalyst with a Claus reaction to produce solid amorphous sulfur. The Selectox process is applied to a plant with direct contact condensers, and works with low ammonia content in the steam. It is recommended for use in relatively large units as its complexity requires high capital costs, but offers low operating costs.

2.2.7 THIOPAQ

This process was first developed for removing H_2S from natural gas streams, and it involves the use of microorganisms for oxidizing the H_2S to elemental sulfur. The gas containing the hydrogen sulfide is absorbed in an alkaline solution under pressure in a first absorption step. The dissolved sulfide is oxidized into the elemental sulfur in a reactor, per Benschop, et al., (2002). The THIOPAQ method was found to be only used in the gas industry and would require further research and development to determine its suitability for geothermal power plant conditions.

2.2.8 Burner-scrubber process

The burner-scrubber process incinerates the non-condensable gases liberated from the geothermal fluids. After the gases are incinerated, the resulting compounds, mostly SO_2 and CO_2, are scrubbed with water, per Stephens, et al. (1980) and Mamrosh, et al., (2012). This process can operate with both types of condensers, although direct contact was preferred. Its operation is strongly dependent on the composition of the geothermal steam, specially regarding the concentration of ammonia. If the geothermal steam has a low NH_3 concentration, then the process is characterized by having high capital costs but low operating costs, making it more suitable for large plants. However, if the NH_3 content is high, the process has low capital costs but high operating costs, making more suitable for small geothermal units. As discussed by Stephens, et al., (1980), this process requires the non-condensable gas composition to be flammable, relying particularly on the concentration of compounds such as H_2S, CH_4, and H_2. An irregular flow of combustible gases from the ejectors can lead to marginal flammability and an intermittent operation of the burner. If these problems require the additional input of fuel such as propane to incinerate the gas, the economics of this abatement system may become unfavorable.

2.3 Methods C: Condensate water

Type C Methods, also called "secondary abatement", are applied to remove H_2S that is partitioned into the water in the condenser before the water makes it to the cooling tower and the H_2S is liberated there. These methods can work with both direct contact and surface condensers, but the volume of water that must be handled for a direct contact condenser is significantly larger. The methods reviewed in this category are the H_2O_2 process and steam stripping.

2.3.1 The H_2O_2 process

Stephens, et al., (1980) point out that this process treats the water with hydrogen peroxide to oxidize the H_2S into elemental sulfur (under acidic or neutral solutions) or sulfates (under basic solutions). This abatement method was used in a demonstration project of an enhanced geothermal system in the Northwest Geysers Geothermal Resource Area to control H_2S emissions during well construction, reports RMT Inc. (2010). The H_2O_2 process can operate well with both type of condensers, and is well suited for plants with a high concentration of ammonia in the steam, as this favors the dissolution of H_2S into the aqueous phase. It has low capital costs but high operating (chemical) costs, so it is best suited for small units or certain short-term operations.

2.3.2 Steam stripping

This abatement method is analogous to a water scrubbing process, whereby the scrubbing is done by clean steam. Here the H_2S contained in the condensed water is stripped using waste steam from the steam ejectors, according to Houston and Domahidy (1981). This process can also be installed with both types of condensers and is effective in settings with low ammonia concentration in the steam. Its high capital and low operating costs make it ideal for use in large power plants, if sufficient quantities of waste steam are available.

2.4 Methods D: Hybrid systems

Type D Methods are hybrid systems, which can perform treatment on both the condensate stream and the gas stream resulting from the condenser stage of the energy production process. The methods reviewed in this category are the Dow-Spec RT-2 and BIOX processes.

2.4.1 Dow-Spec RT-2

This process combines the burner-scrubber process previously described with an iron chelate chemical added to the circulating water, and is used to treat the off-gas from the NCG system and the condensate in tandem. The H_2S is incinerated to SO_2, which is scrubbed to form sulfites, which then combine with sulfur from the iron chelate reaction in the circulated water to form soluble thiosulfates. This process is used in Units 5, 6, 7, 8, 11 and 12 at The Geysers, in retrofitted power plants built prior to 1980, mention Farison, et al., (2010). The Dow-spec RT-2 process is currently used in plants with direct contact condensers and low-to-medium NH_3 concentration. Operational costs were found to be best suited for large plants per Farison, et al (2010).

2.4.2 BIOX

The BIOX process is another downstream process, in which the off-gases are compressed and mixed with the condensate before entering the cooling tower. An oxidizing biocide used for biological growth control in the cooling tower, in combination with oxygen, converts dissolved H_2S to water-soluble sulfates. This reduces both primary and secondary emissions of hydrogen sulfide from the cooling towers reports Gallup (1992). This process is currently being used in the John L. Featherstone Geothermal Power Plant, also known as the Hudson Ranch I Geothermal Project, as described by the California Regional Water Quality Control Board (2013). The BIOX process can be used in power plants installed with both types of condensers and is not affected by the concentration of NH_3 in the steam. The process does not require high capital and operating expenses, making it appropriate for installation in both large and small power plants, however the attainable removal efficiencies may not be as high as other methods.

3. DISCUSSION

As can be seen from this brief analysis, each abatement process has its own characteristics, advantages, and disadvantages, making the decision of selecting one somewhat complicated. Some of the methods researched were clearly not yet recommended due to economical or technical limitations, or required additional research and development.

As can be seen in Table 2, the Scrubbing with alkali and BIOX processes appear to be the most widely applicable, because they can be used with both types of condensers, and the composition of the geothermal steam does not have a significant impact. This is particularly beneficial, as a change in the geothermal steam/NCG composition can be expected throughout the operational lifespan of a geothermal power plant.

Both the NCG injection and BIOX processes share the fact that they are the only ones with low expected capital and operation costs. This makes them suitable for treatment of H_2S emissions in both large and small power plants. The NCG reinjection process requires the use of a surface condenser, but can be used with direct contact condenser in conjunction with secondary abatement processes. The BIOX process has greater flexibility in the condenser design and ammonia content criteria.

Table 2: Criteria used for preliminary selection of primary H2S abatement processes

Process	**Condenser Design**	**NH3/H2S ratio**	**Economics**	**Best suitable for**	**Comments**
Copper sulfate	Direct Contact Condenser and Surface Condenser	High	High cap. & op. costs		Not yet proven to be economically feasible
Scrubbing with alkali	Direct Contact Condenser and Surface Condenser	High and low	Low cap & relatively high op. costs	Small plants or temporary abatement	
Liquid redox methods	Surface condenser	Low	High capital costs	Large plants	
AMIS	Direct Contact Condenser	Low		Currently applied in small plants in Italy	Process more or less tailored for Italian field characteristics
NCG injection	Surface Condenser	Low	Low capital operational costs	Small and large plants	
Peabody-Xertic	Surface Condenser	Low	High cap. And high op. costs	Large units	
Fe-Cl hybrid	-				Still under development
Selectox	Direct Contact Condenser	Low	High cap. Cost and low op. Costs	Medium to large plants	Used in 65MW plant in Japan
Biological/THIOPAQ					Needs research for applicability in a geothermal setting
Burner-scrubber	Surface Condenser and Direct Contact Condenser	High and low	High NH_3 content: High cap. And low op. Costs Low NH_3 content: Low cap. And high op. Costs	Low NH_3: Large units High NH_3: Small units	DCC preferred.
H_2O_2 process	Surface Condenser and Direct Contact Condenser	High	Low cap. Costs and high op. Costs	Small units	Recommended only as secondary abatement.
Steam Stripping	Surface Condenser and Direct Contact Condenser	Low	High capital costs and low operating costs	Large units	Recommended only as secondary abatement.
Dow Spec RT-2	Direct Contact Condenser	Low to Medium	High capital costs	Large units	
BIOX	Surface Condenser and Direct Contact Condenser	High and low	Low capital and low operating costs	Small and large	

On the other hand, the liquid redox, Peabody-Xertic Selectox, steam stripping and the RT-2 methods depend on a complex process, which causes them to have high capital costs, making them more suitable for large units. However, the steam stripping method appears to have a comparatively low H_2S removal efficiency, limiting its usefulness to being used only in combination with other abatement systems, or for settings without stringent requirements.

The NCG system off-gas processes selected (Stretford, Unisulf, LO-CAT, and RT-2), alongside the NCG injection and Selectox are strongly dependent on the concentration of ammonia in the geothermal steam, and subsequent partitioning of H_2S into the condensate. Therefore, adoption of these systems requires taking into account not only type of condenser in the geothermal plant, but the evolution of the composition of NCGs in the geothermal system.

Finally, it is the BIOX process that seems to provide many benefits and fewer disadvantages of the systems analyzed, if removal efficiency is not a prime consideration. However, it must be stated that these processes must be subjected to a more rigorous and detailed technical and economical analysis for a specific setting.

The methods showing the most flexibility are summarized in Table 3. Methods C (secondary abatement, from condensate) are used as complimentary processes to the primary abatement methods.

Figure 2, shown below, attempts to serve as a decision tool for choosing candidate abatement methods for different geothermal plant and geothermal steam compositions. It is a basic outline designed to provide a quick, graphical summary of the methods selected from the total number of methods presented in the literature review.

Table 3: Summary of recommended H2S abatement methods

Method	Comments
Scrubbing with alkali	Recommended for small units or transient abatement needs
Liquid Redox methods	Specifically the following: Stretford, Unisulf, LO-CAT II. Has limitation regarding the condenser design but can be used in combination with H_2O_2 process or steam stripping
NCG injection	As with the liquid redox methods, has limitation regarding the condenser design but can be used in combination with H_2O_2 process or steam stripping.
Selectox	Has limitation in the required condenser design.
Dow-Spec RT-2	Has limitation in the required condenser design, and requires composition of NCGs to be flammable.
BIOX	Combines flexibility in suitable condenser types, ammonia content and expenses; limitation on removal efficiency.

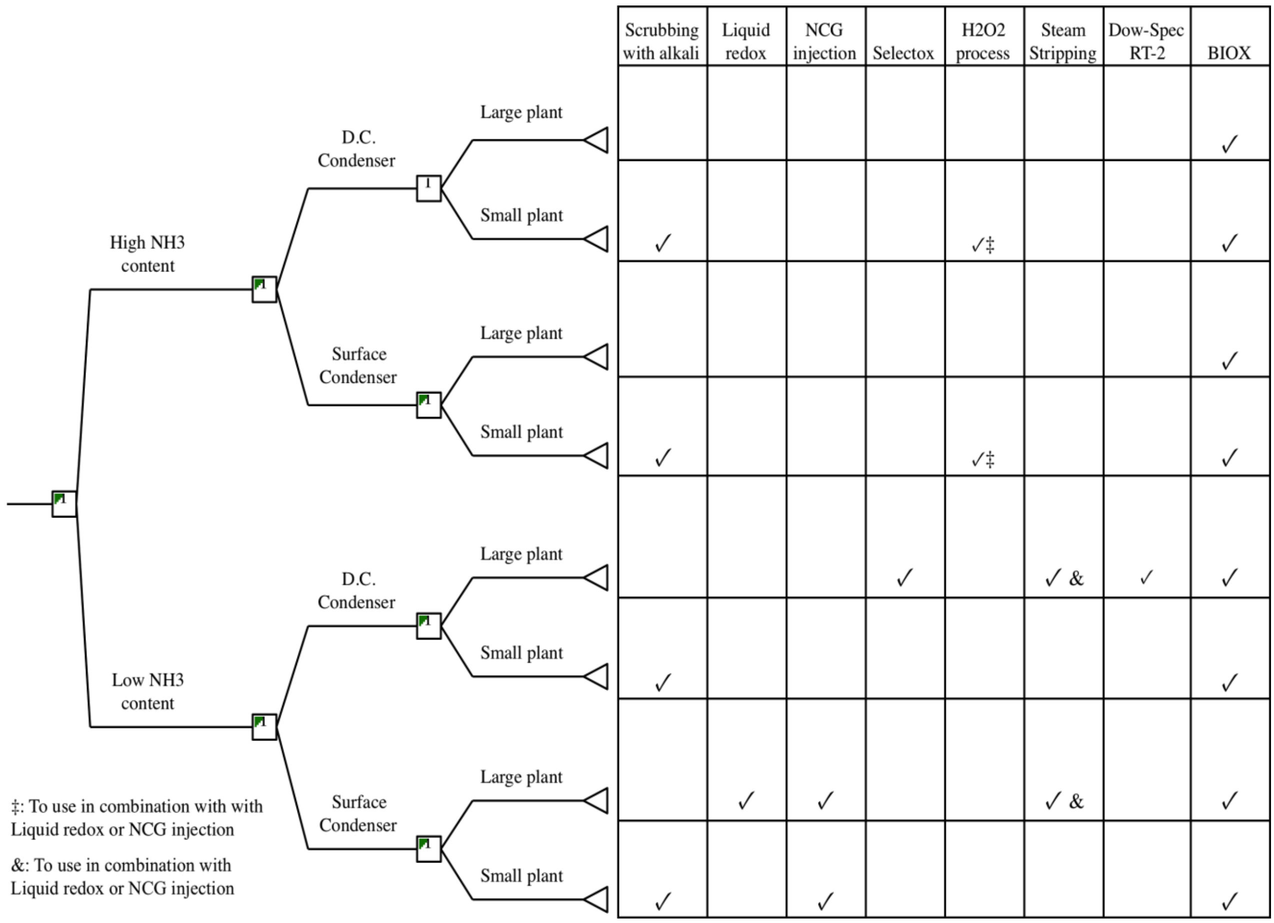

Figure 2: Proposed H2S abatement system selection decision tool

4. NCG ABATEMENT STRATEGIES AT THE HELLISHEIDI GEOTHERMAL PLANT

The Hellisheidi geothermal power plant is a combined heat and power plant located in southwest Iceland, in a geothermal area known as Hengill. This geothermal area, described by Gunnlaugsson and Gíslason (2005), lies in the middle of the western volcanic zone in Iceland, on the plate boundary between North America and the European crustal plates. The rifting of the two plates has opened a North-Northeast system of normal faults and magma intrusions. This rift zone is highly permeable and numerous fumaroles and hot springs emerge at the surface. This is one of the most extensive geothermal areas in the country, with surface measurements, heat distribution and subsurface measurements indicating an area of around 100km^2.

In 2001, Orkuveita Reykjavikur started developing the power plant. The first phase of construction included two high-pressure 45MWe Mitsubishi Heavy Industry turbines that went online in late 2006, and then one low-pressure 33MWe Toshiba turbine that went online in 2007, report Gunnlaugsson and Gíslason (2005). In Fall 2008, two additional 45MWe turbines began operation. The last power expansion went online in 2011 and consisted of two 45MWe turbines, according to Mannvit Engineering, the plant designer.

Interest in abating H_2S emissions from the Hellisheidi power plant began in 2008. As the previous section has described, there are various methods for abating these emissions in geothermal power plants. Between them, they provide many geothermal plants, operating in a wide variety of geothermal fields, different economically viable and relatively flexible techniques for minimizing gaseous fumes released to the atmosphere. However, none of these seem to be a reasonable alternative for Reykjavík Energy, due to the geographical location of the country. The relatively remote setting of Iceland placed constraints on purchasing of the materials and/or chemicals required for the abatement system, or the possible profit from selling the byproducts of the abatement method.

Feasibility studies were performed on the possibility of abating H_2S by means of conversion to amorphous sulfur (S^0) and sulfuric acid, among other possibilities, but there was found to be no market for any of the byproducts of these systems at this location. The market value of S^0 was too variable, and it was possible for the export costs for sale overseas to be greater than the selling price, making it an economically unappealing option. Another possibility looked into was the burial of S^0, but its reaction with water, and subsequent formation of sulfuric acid, required the combined burial of S^0 with shell sand to avoid environmental issues, which would neutralize the acid formed due to its high calcium content. Once again, this proved to be a rather costly option.

At the same time, in response to the public concern as to the unforeseen side effects of H_2S pollution, the Minister of Environment of Iceland issued Regulation 514/2010, which limits the maximum concentration of H_2S in the atmosphere. Following this, and taking into account the feasibility studies performed, Reykjavík Energy commissioned the construction of a pilot-scale distillation column to explore the possibility of separating the CO_2 and H_2S present in the non-condensable gases as a pre-treatment process of the Carbfix and Sulfix processes, which aim to fix reinjected gases in the reservoir through gas-rock interactions.

Moreover, with this process, several alternatives are promising to make the system more economical, particularly the stream of purified CO_2. As discussed by Ragnarsson (2003) and Orkustofnun (2003) there is increasing interest in the possibility of using the purified stream of CO_2 in greenhouses to increase the production of crops grown in Iceland, particularly tomatoes, while reducing the purchasing costs of the CO_2 needed for their growth. Research has also been done to sequester carbon dioxide from geothermal plants' flue gas with photosynthetic microalgae. According to Brynjófsdóttir and Svavarsson (2011) and Suryata, et al., (2010), the mitigation of carbon dioxide emissions through these methods could potentially be profitable from the production of cosmetics, nutrients, fish feed, and even biofuel by using the biomass produced by the algae.

4.1 Carbfix

In the Carbfix process, CO_2 produced with the NCGs during the geothermal production process are dissolved into produced formation fluids and well water and then injected back into the subsurface. The dissolved CO_2 will deposit as solid mineral assemblages in the subsurface over time. Calcite ($CaCO_3$) is predominantly the most abundant carbonate to form in reactive transport simulations. Magnesite-siderite ($MgCO_3$-$FeCO_3$) solid solution also precipitates, but in significantly lower quantities, reports Aradóttir, et al., (2012). Once dissolved in the reinjection fluid, CO_2 is no longer buoyant compared to pore-fluids, which prevents escape from the geothermal formation.

Reactive transport simulations of a 1200 ton pilot injection predict 85% CO_2 mineral capture within 5 years and 100% capture within 10 years. Approximately 3% of the total geothermal gas coming from the power station is currently being separated and re-injected. The gas stream coming from the station consists of approximately 68.9% CO_2, 27.5% H_2S and 1.6% H2, according to Arnarson (2013). Simulations of the full-scale injection scenario at Hellisheidi power plant performed by Aradóttir, et al., (2012) predict 80% CO_2 mineral capture after 100 years

4.2 Sulfix

Sulfix uses a similar method to that of the Carbfix project. Instead, the H_2S is dissolved into the warmer water from the flash separators (at 90°C) and pumped down to below 800m, where the dissolved gas will mineralize as sulfide metals. This abatement technique is ideal because it uses the same natural processes that produced the gases and sequesters them in the reservoir, reports Júlíusson (2013). This project is still in a pilot phase, however it is expected to go on to full production phase in order to meet the new legislative H_2S concentration requirements.

5. CONCLUSIONS

Many H_2S abatement processes have been developed over the past decades. Selecting an appropriate abatement method requires analyzing several variables, such as geofluid characteristics, required abatement efficiency, process economics, and geothermal plant design, among others. Thus, the process of selecting an abatement method can be complicated. The present work explored some of the most widely used H_2S abatement methods in the industry and provided a preliminary assessment on the basis of available qualitative criteria. More detailed, quantitative assessment procedures are needed for particular cases for selecting the most appropriate abatement method. This paper, however, attempts to serve as a preliminary screening tool for narrowing the search for abatement systems, or identify paths for future research. By using the criteria described in Table 2, some processes, or combination of processes are proposed.

The key variables identified during the literature research are the following:

- The economics of the process and the balance between capital and operating costs.
- The ratio of ammonia–to–hydrogen sulfide in the geofluid, as the pH is key to H_2S partitioning, and the type and rate of reaction that can take place along the abatement process.
- Condenser design. The degree of partitioning and chemical reactions taking place among different processes can require a different type of condenser in the power plant.

As mentioned before, this work only aims to provide simple guidelines and to point out the key variables identified during the literature research in this topic. This relatively small group of processes must be subject to a more detailed, quantitative technical and economic assessment for final selection of the optimum process, or combination of processes. The ongoing work at the Hellisheidi field will be a prime testing ground for the NCG injection and fixing processes.

6. AKNOWLEDGEMENTS

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