



UNITED NATIONS
UNIVERSITY

GEOTHERMAL TRAINING PROGRAMME
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Reports 2007
Number 20

DESIGN CONSIDERATIONS FOR RELIABLE ELECTRICAL, CONTROL AND INSTRUMENTATION SYSTEMS IN GEOTHERMAL POWER PLANTS WITH EMPHASIS ON HYDROGEN SULPHIDE RELATED PROBLEMS

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ABSTRACT

Hydrogen sulphide is a corrosive gas widely present in the air at most geothermal power plants. This report describes the mechanism and some of the effects of corrosion in electrical equipment in the presence of hydrogen sulphide at geothermal power stations. Electrical and control equipment are often not designed to operate in corrosive environments; hydrogen sulphide is a corrosive gas, particularly to copper and silver. Therefore, special measures and systems must be considered in order to keep this corrosive gas from contacting sensitive equipment containing those metals. Other equipment in the plant can also suffer from the attack of hydrogen sulphide, but it is possible to minimize the adverse effects by making a careful selection of the materials used and maintaining appropriate environmental conditions. Instrumentation is also exposed to the particularities of the geothermal fluids; the performance and expected problems of some of the main instruments used in the power plant are presented. By appropriate design of geothermal power stations, and taking into consideration and addressing the possible ways in which hydrogen sulphide and geothermal fluids can attack equipment, it is possible to avoid premature failures and attain high plant reliability.

1. INTRODUCTION

Geothermal power plants are important contributors of renewable energy in many countries around the world. Because they are commonly used as base load energy suppliers, these plants are expected to have very high reliability and availability. Revenue losses, added to the penalties for non-served energy due to power plant failures, result in very costly events.

On the other hand, the trend in recent years has been to cut down the number of technical staff working permanently at power stations, downsizing the operations and maintenance departments in order to gain cost efficiency. Fewer personnel are supervising the process, many of the tasks are being automated and remote supervision of the process is being performed. In some power stations there is no permanent maintenance department and one maintenance crew is in charge of servicing several plants.

In this context, it seems quite evident that great effort is needed to minimize equipment failure and unplanned plant outages. The reliability of a plant starts with the design itself. One of the tasks of the design engineer is to try to foresee the conditions to which equipment will be exposed, and to specify equipment that has proven to perform reliably in these conditions. If the result is impractical or too expensive, the work of the engineer is to modify conditions in order to make them more benign and suitable for the equipment.

Control, instrumentation and electrical equipment can be very sensitive to the environment in which they operate. Temperature, humidity, the presence of corrosive gases, and a tendency to develop scaling are all conditions which, if they are outside the limits the equipment can tolerate, will seriously affect the lifetime and reliability of that equipment.

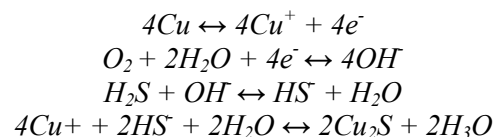
Throughout years of experience building and operating geothermal power plants, engineers have gained a lot of knowledge regarding the ways in which electrical, control and instrumentation systems can be affected by corrosive atmospheres and geothermal fluids. This report tries to present some of this knowledge and past experience, and design features of modern geothermal power stations in order to address these adverse conditions and obtain the desired plant reliability.

2. HYDROGEN SULPHIDE RICH ENVIRONMENTS

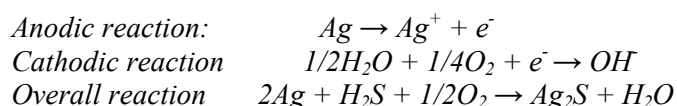
2.1 Corrosion of copper and silver

Corrosion, which can be defined as a destructive attack of a metal by chemical or electrochemical reaction with its environment, is a general phenomenon that attacks materials in most plant systems, including electrical systems. The most widely used materials for electrical conductors and current carrying parts are copper, aluminium and silver. Aluminium is resistant to atmospheric corrosion by H_2S . Therefore, the mechanism of atmospheric corrosion of copper and silver in an atmosphere containing H_2S will be presented.

When copper is exposed to air containing moisture, it develops a surface film of Cu_2O through an electrochemical mechanism. This film is considered to be a very tough layer which performs a protective function and prevents further corrosion of the underlying copper, making it a material with a well known good performance regarding atmospheric corrosion. However, when the presence of hydrogen sulphide is added, not only do copper oxides form but also a film of Cu_2S , which is a semiconductive layer with a higher ionic conductivity and, as a result, the corrosive process occurs considerably faster because no protective layer is formed and the corrosion rate does not decrease with time. The rate of corrosion is increased with an increased relative humidity in the air; additionally, the presence of hydrogen sulphide also causes the copper oxide layer to be thicker, that is, the oxidation rate is higher. The reactions that create the Cu_2S film are (Tran et al., 2003):



In the case of silver, the corrosive product is silver sulphide (Ag_2S). The formation of this corrosive product is again accelerated by humidity in the air. Silver sulphide can continue growing in the shape of long needles called "silver whiskers", which is a problematic phenomenon to be explained later. A proposed reaction for the formation of Ag_2S from silver exposed to ambient air containing H_2S and humidity is (Kim and Payer, 1999):



2.2 Measurement of hydrogen sulphide in some geothermal power plants

The concentration of hydrogen sulphide in the area surrounding geothermal power plants is an important parameter that is normally monitored by plant personnel. This concentration will be a major determinant in the level of toxicity to which plant personnel will be exposed and also of the level of corrosion that equipment could suffer if not protected. When H₂S removal systems are in operation, this concentration determines how much demand will be imposed on it. Many factors can affect this parameter, like the hydrogen sulphide content in steam, the average wind speed and direction, and the proximity of the plant to wells and hot springs. But one of the most important is the amount of steam being used at the plant, which relates directly to the amount of H₂S being exhausted by the non-condensable gases extraction system. Because hydrogen sulphide has a higher density than air, it will accumulate in low points, like the cellars in which the wells of some geothermal plants are located. For this reason, special precautions would need to be taken when going into them.

A list of some typical concentration levels at some geothermal power plants around the world is presented below (Table 1). As can be expected, this concentration is not uniform throughout a plant, but some of the higher values are presented. It will be shown later that these concentration levels are high enough to cause considerable corrosion to electrical and electronic equipment; therefore, special measures must be taken to avoid excessive corrosion and maintain the expected reliability of the power plant.

TABLE 1: Concentration of H₂S in air surrounding some geothermal power plants

Location	H ₂ S concentration [ppb]	Source
Svartsengi, Iceland	145	Ívarsson et al., 1993
Nesjavellir, Iceland	2500 ⁽¹⁾	VGK, 2005
Hellisheidi, Iceland	147 ⁽²⁾	VGK, 2005
Ahuachapán, El Salvador	610	LaGeo, 2007
Berlín, El Salvador	26	LaGeo, 2006a
Onikobe, Japan	400	Dipippo, 1978
San Jacinto Tizate, Nicaragua	150	LaGeo, 2006b

- (1) Highest measured value;
- (2) Measurement taken before power plant was constructed; higher levels can be expected now, after the power plant has started operation.

2.3 Other industries with H₂S rich atmospheres

Although electrical and electronic equipment are usually built to some standard for general application (ANSI, NEMA, IEC, etc.), and even when some of them, like digital relays, are designed and tested to survive in harsh industrial environments, the hydrogen sulphide corrosion issue in particular is not usually addressed by manufacturers, except under specific request by the buyer. This does not mean that the geothermal industry is the only one that faces this problem; there are many other industries in which it is common to find considerable hydrogen sulphide concentrations in the air, for example (ISA, 1985):

- Sewage treatment plants;
- Paper mills;
- Fossil fuel processing plants;
- Wood pulping facilities;
- Ore smelting;
- Sulphuric acid manufacturing;
- Steel electric and blast furnaces;
- Rubber manufacturing.

In all of the above mentioned industries, special considerations need to be taken in the design of electrical and control systems. It is convenient to make use of what has been written about this subject in specific publications from these industries.

3. DETRIMENTAL EFFECTS OF HYDROGEN SULPHIDE IN ELECTRICAL AND CONTROL EQUIPMENT

Electrical and control equipment can be seriously affected by the attack of hydrogen sulphide in geothermal plants. The result will be a premature failure of equipment and diminished plant reliability and uptime. These problems can be avoided by appropriate design, selection and protection of components. Some of the problems experienced in the plant by H₂S attack are discussed below.

3.1 Electronics

The environmental conditions in which electronic equipment, like computers, instruments, PLCs, relays, among others, operate determine to a great extent the lifetime expectancy of those equipments. Environments containing gases like hydrogen sulphide, which reacts with copper and silver, are likely to cause corrosion in electronic equipment. In one laboratory, it was estimated that about 20% of all electrical and electronic failures were caused by corrosion problems. In H₂S environments, an even higher ratio of failures due to corrosion problems may be expected.

The effects of corrosion on the reliability of electronic equipment is of growing importance for two main reasons: first, because of the increasing need of more cost-effective products as well as products which integrate more functionality in one single device; electronic components are being miniaturized, with thinner and more closely spaced metallic sections. And second, this equipment is being exposed to harsher environments. Some integrated circuits have microscopic leads and conductor tracks less than 1 μm thick; in these kinds of components, even small traces of corrosive gases can produce enough corrosion to lead to failure.

In order to being able to mount more devices into one single board, designers have opted for surface mount components instead of through-hole components. This can be seen in most of the microprocessor-based relays, meters, and others. Surface mount resistors are composed of a resistive element, usually silver, covered with a ceramic insulator substrate, and a layer of epoxy on top (Figure 1). Humidity and temperature variations can cause the protective epoxy layer to adsorb the hydrogen sulphide, causing it to expand and let the corrosive gas come in contact with the silver metal (Midence et al., 2007). The result is corrosion, manifested through the formation of thin, long needle shaped crystals of silver sulphide, called silver whiskers, which can cause short circuits or thermal failures (Figures 2 and 3).

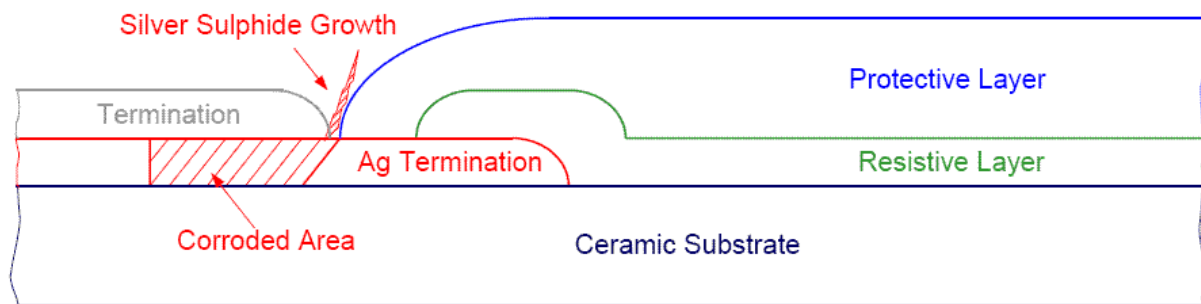
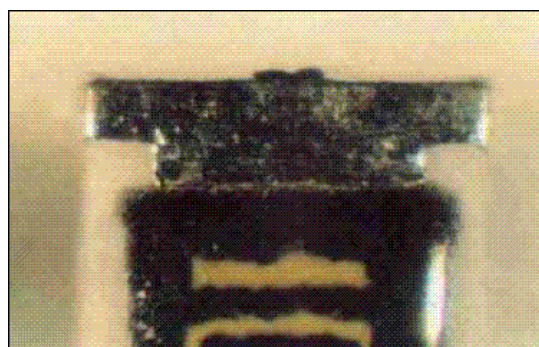


FIGURE 1: Defective product affected with the growth of silver sulphide (KOA, 2002)



(a)



(b)

FIGURE 2: Silver sulphide “whisker” growth in a surface mount resistor; a) Before a sulphur test; and b) After (KOA, 2002)

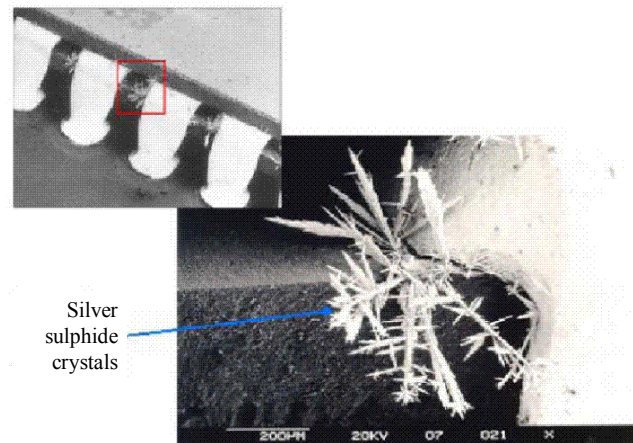


FIGURE 3: Corrosion to thick internal silver/palladium film (ERA, 2002)

Some components have been specially designed to withstand extremely corrosive atmospheres, and these have undergone tests to demonstrate an ability to withstand gas corrosion tests such as IEC 60068-2-60: a flowing mixed gas corrosion test. Protection can be achieved by applying a special conformal coating to the circuit boards. These coatings are approved to military specifications MIL-I-46058-C, type AR, ER and UR, and are also UL recognized, according to specification UL746C/94, for indoor and outdoor applications (Midence et al., 2007), but unless the component is known to comply with these corrosion tests, they have to be isolated from the hydrogen sulphide to prevent rapid deterioration.

3.2 Power contacts and current carrying parts in circuit breakers

Silver is one of the most widely used materials for plating the contacts in power circuits, like power circuit breakers, and contactors because of its superior conductivity and longevity (Chudnovsky et al., 2002). It behaves well under most common environments, but in hydrogen sulphide rich atmospheres, it forms silver sulphide (Ag_2S), which, as will be explained, is a very undesirable phenomenon.

It has been reported that in some pulp and paper plants, failures have occurred because of highly conductive long thin filaments growing in the contacts, particularly in the areas with higher temperatures, causing short circuits to grounds or between poles. These filaments have been called silver whiskers, and are composed mainly of silver (Chudnovsky et al., 2002).

When exposed to an atmosphere with a hydrogen sulphide concentration as low as 0.1 ppm, silver plated copper will develop a layer of silver sulphide (Ag_2S), which has a relatively higher electric resistance; this will increase the contact resistance causing an increase in the formation rate of the silver sulphide layer. At some point in this reaction, the silver whiskers will start to form and grow, and if left for enough time, they will grow until they touch an adjacent grounded structure inside the compartment or even an adjacent pole, causing a ground fault or short circuit (Figure 4).

To overcome this problem, some paper mills have started specifying tin plating in all the current carrying parts exposed to H_2S . Tests have been done and tin plated copper shows no evidence of damage (Riddle, 1990). However, there are special considerations when dealing with sliding surfaces, like moving and stationary arcing contacts, because of the possibility of galling, which is a form of “cold welding” that can occur in tin plated copper. Because of this, some manufacturers are reluctant to supply tin plating on both stabs or sliding surfaces. This phenomenon has not been reported in the mills, where some tin plated stabs and contactor fingers have been used; however, “no-oxide” lubricants are generously used on them (Riddle, 1990).

3.3 Control circuits

Relays and switches can deteriorate significantly if left to operate in a geothermal environment rich in hydrogen sulphide. Experience has shown that the surfaces of copper or silver plated copper contacts will develop a tarnish film on the surface. This film will increase the resistance on the current path, and can lead to malfunctions of low voltage and low current circuits. Corrosion has also occurred on other exposed elements like relay springs and relay coil copper windings.

Many of the corrosive reactions in the contact surface will take place in a thin aqueous electrolyte film on the surface, which result from a solution of hydrogen sulphide and other impurities in air. Relative humidity has an important influence on the corrosion reaction rate. Below a relative humidity of about 50%, there is very little reaction caused by these deposits, but when humidity reaches 50-60% (critical humidity), the rate will sharply increase. At low humidity, the reactions do not depend on any aqueous film but instead will occur by direct action, yielding different corrosion products (Antler et al., 1973).

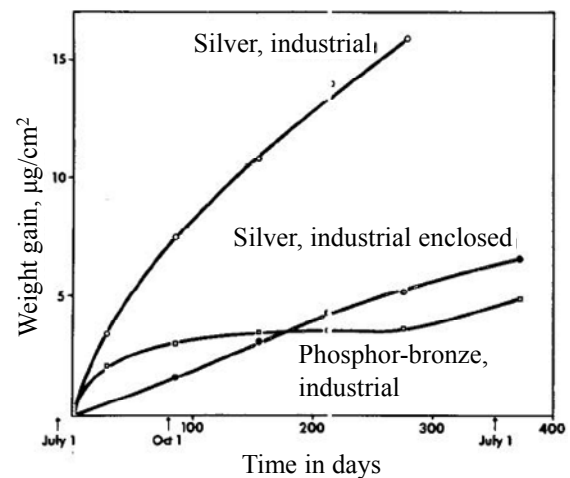


FIGURE 5: Tarnish rate of silver and bronze and the effect of air circulation (Antler et al., 1973)

The air circulation is also an important factor. Figure 5 shows the result of an experiment to see how air circulation affects the rate of corrosion on silver surfaces. Corrosion occurs much faster when the specimen is in open air than when it is inside an enclosure. The reason is that in the open air, more sulphur atoms impinge on the surface at a given time. Thus, the use of cooling fans to enhance the flow of unfiltered air into a cabinet could result in adverse effects. The reaction rate seems to increase with increasing temperature (Antler et al., 1973). Due to this, many plants around the world have opted to specify tin plated contacts instead of silver plated or bare contacts. Tin has given satisfactory results in hydrogen sulphide rich atmospheres.

As an additional safety measure, it is a design practice in some countries to use higher control circuit voltages, for example 125 VDC instead of 24 VDC, in order to have a wider margin to overcome additional contact resistance caused by the formation of corrosion film in electrical contacts at relays, switches, push buttons, selectors, etc.

3.4 Conductor material and conductor corrosion protection

When exposed to a corrosive atmosphere, the copper strands that compose an electrical conductor will be attacked by corrosion. This makes the attack of hydrogen sulphide on copper even more important in control cables, which have much smaller conductor areas than power conductors (Figure 6). Some paper mills have reported that silver plated or bare copper wiring has been found to corrode completely and break or corrode down to one or two remaining strands (Riddle, 1990). For this reason, plant engineers in paper mills and geothermal power plants have decided to exclusively specify tinned copper for control and instrumentation circuits. As this is a relatively cheap measure, it is even used in areas of the plant where the environment is controlled and hydrogen sulphide is removed by special treatment (Moore, 1989). Fine stranded power cables are available from cable suppliers and have the advantage of more flexibility; nevertheless, the use of these types of power conductors in geothermal plants should be avoided if possible, since experience has shown that the fine strands corrode quicker than coarse stranded conductors.

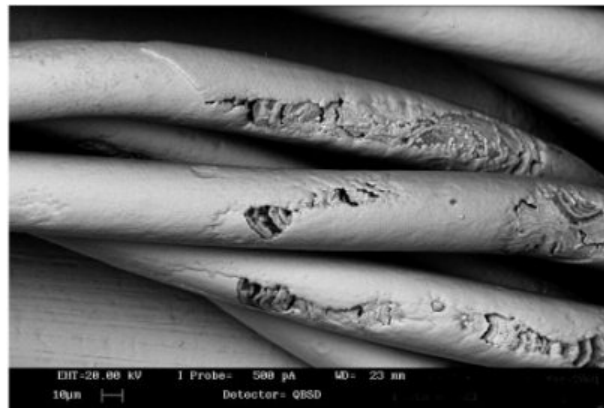


FIGURE 6: Corrosion of copper strands (ERA, 2002)

The general practice is to specify tinned copper conductors for power circuits, but sometimes it is hard to find suppliers that can offer tinned conductors in bigger cable sizes. In general, conductors are protected from the hydrogen sulphide atmosphere by the insulation and the jacket; but at the ends of the cable, where the terminals are installed there is a small gap between the base of the terminal and the end of the insulation which could be attacked by hydrogen sulphide. To prevent this, some plants use heat shrinkable sleeves at these points (Figure 7). Another alternative is to coat the exposed copper areas with special corrosion protection lubricants, sometimes called “no-oxide” lubricants.



FIGURE 7: Heat gun used to blow hot air to heat shrink sleeves; a cable termination with a heat shrink sleeve can be seen beside the gun

Conductor terminals have to be selected with closed ends, because some of them have a small opening at the end through which contaminated air could enter and corrode the inside cable strands.

3.5 Cable insulation

Not much attention has been given to the specifications of power and control cable insulation in geothermal power plants, but experience in some other industries could be used to avoid some potential problems from the interaction of insulation and jacket materials with hydrogen sulphide.

In the early seventies, one Japanese cable manufacturer investigated failures of polyethylene and crosslinked polyethylene power and control cables which were exposed to H_2S and water. Sections of cables which had failed in a chemical plant after -8 years of service (Tabata et al., 1971), and also a

submarine cable (Fukuda et al., 1980), were analyzed. In both cases, the cable insulation exhibited the formation of conductive tree-like structures, which they called “sulphide trees” (Figure 8). After examination of the composition of these trees, they found out that they were composed mainly of cuprous sulphide (Cu_2S) and cuprous oxide (Cu_2O), which have relatively good conductivity, and caused insulation failure (Tabata et al., 1971).

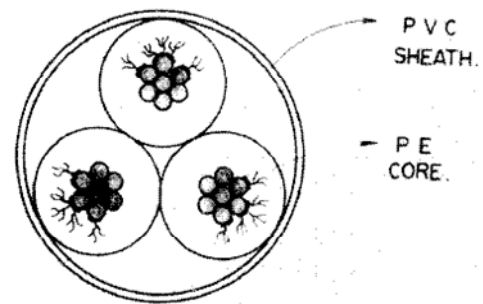


FIGURE 8: Distribution of sulphide trees in a cross-section of three core stranded cable; polyethylene insulation is 1 mm thick (Tabata et al., 1971)

They studied the formation mechanism through accelerated tests in polyethylene cables in controlled conditions, where the acceleration factor was achieved by an increased H_2S concentration. What they found is that they were able to reproduce in the laboratory the same sulphide trees encountered in the field, and were able to confirm their theories about the growth mechanism of these structures.

The growth mechanism was explained as follows: Sulphides, such as H_2S , are able to permeate the PVC jacket and polyethylene insulation, and when they reach the copper conductor, Cu_2S and Cu_2O are formed at the interface between copper and the insulation in a bush-like pattern (Figure 9). The main driving force for the bush-like growth is the pressure resulting from the volumetric change with the crystallization of Cu_2S . The bush-like area will grow even if no voltage is applied to the conductor. The next stage is the growth of tree-like structures, which form at the tips of bush-like growths. These second structures will not form without an applied voltage, but even if voltage is applied they do not always form. It can be seen in Figure 10 that the longer the trees are, the lower the insulating resistance of the specimen. It can also be seen that, like many chemical reactions, the growth of the trees occurs faster at higher temperatures. A similar behaviour could be expected from XLPE (Anelli et al., 1997).

To overcome this problem, engineers in some geothermal plants specify tinned copper as cable conductors (Moore, 1989). According to some cable manufacturers, some specially formulated tree-retardant compounds have solved this problem, but in any case XLPE cables have to be protected with a jacket that isolates the insulation from the environment containing moisture and H_2S . And lastly, some end users choose EPR for cables exposed to hydrogen sulphide and water, because this material does not seem to be affected by this phenomenon.

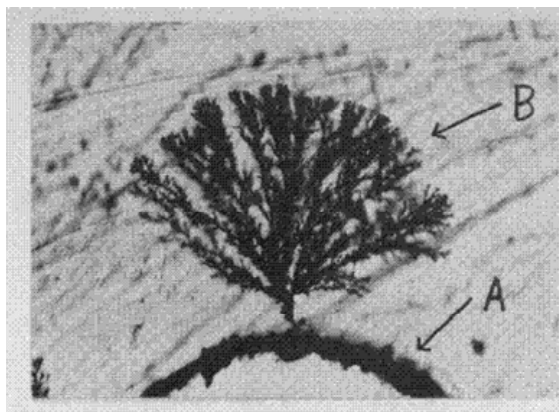


FIGURE 9: Complete sulphide tree; its length is about 300 micron. Arrow A: Bush-like growth; Arrow B: Tree-like growth (Tabata et al., 1971)

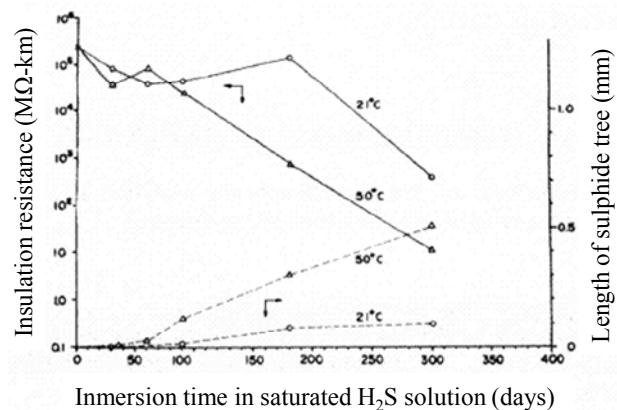


FIGURE 10: Relationship between immersion time in saturated hydrogen sulphide solution and insulation resistance and also length of sulphide trees; shown at 21 and 50°C (Tabata et al., 1971)

3.6 Air conditioning equipment

Air conditioners are common equipment found in geothermal power plants. Even though they are obviously not primary equipment in the plant's process, they accomplish relevant functions like maintaining an optimal temperature in electrical and control rooms, and electronic spare parts rooms, so equipment is operated or stored in a more benign environment, therefore extending its useful life. It has been experienced that standard air conditioning units handling hydrogen sulphide rich air can fail because of refrigerant leaks in the copper coils after only one year of service.

The standard air conditioning unit coils are manufactured from aluminium fins mechanically bonded to copper tubes; the fins are stacked on parallel rows of copper tubes, typically one to three adjacent layers, and then these tubes are mechanically expanded to make contact with the fin sheets (Figure 11).

There are two main types of corrosion that could be expected in the coils in a geothermal plant: Firstly, galvanic corrosion, caused by the aluminium fins and copper tubes in close proximity to each other exposed to an electrolyte, usually containing sulphur, chloride or nitrogen. The less noble material, aluminium, will sacrifice itself and create an oxide build-up and the formation of gaps or voids at the interface between the fin shoulder and the tube, producing an increase in thermal resistance and leading to a decrease of the unit's efficiency.

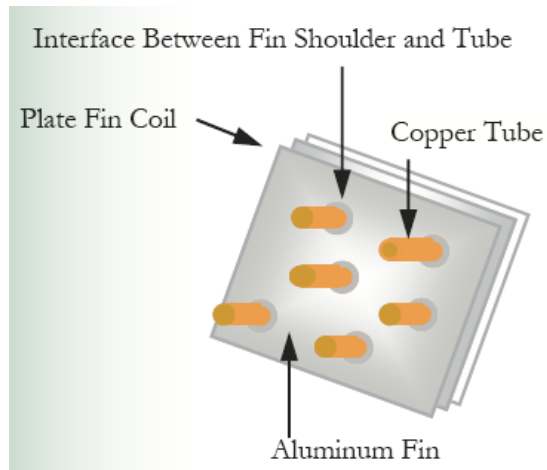


FIGURE 11: Standard coil construction (Bronz-Glow n.d.)

The second type is general corrosion, where copper is attacked directly by an agent like hydrogen sulphide. The walls of the tube form a dark corrosion layer and in some points where the attack is concentrated, pitting occurs and the refrigerant leaks, as shown in Figure 12.

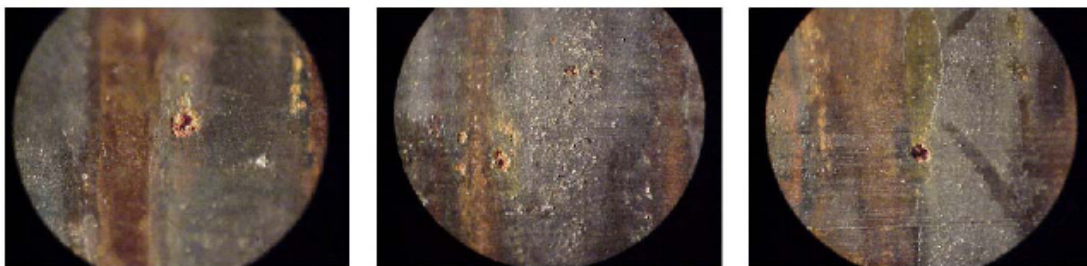


FIGURE 2: Microscopic images of pits in copper tubing, 60x magnification (Field, 2002)

In some applications in the geothermal power plant where the areas to be cooled contain sensitive equipment like computers and PLCs, air conditioning units will handle clean air that has been previously treated by special gas-phase filtration units (see Section 4.1.2) and, therefore, these corrosion problems are not likely to be experienced. But for the cases where a no gas-phase filtration is required for cooling areas not containing sensitive equipment, manufacturers propose some solutions to these problems. One of them is the use of protective coatings, applied when manufactured by electro coating all the coil surfaces for complete encapsulation. These epoxy coatings are flexible to prevent breaking during thermal expansion. Some other companies offer field applied spray coatings, but because of the cleanliness required for successful product application, and the limitations of the method to reach hard-to-access areas, particularly in multiple row coils, this method does not provide sufficient protection. The last option is to specify coils made of a material resistant to hydrogen sulphide corrosion. Some manufacturers offer an all-aluminium construction.

3.7 Grounding grid

The extent to which metals will be attacked by corrosion when buried in soil, the soil corrosivity, depends on many properties of the soil:

- *Soil resistivity*: Because soil corrosion is an electrochemical phenomenon in which the soil and the moisture in it act as an electrolyte, the resistivity is one of the most important parameters in assessing the corrosivity of the soil. A resistivity survey should be one of the first steps carried out when designing a grounding grid. Lower resistivity soils will allow a free flow of electrons, facilitating corrosive reactions. If the supply of air to the metal surface is high enough to allow the cathodic reactions to continue and prevent the growth of anaerobic sulphur reducing bacteria, it can be stated that the soil corrosivity is roughly inversely proportional to its resistivity (Wranglén, 1972). Table 2 shows the relationship between soil resistivity and corrosion rate; the increased salt content causes increased electrolyte conductivity (decreased resistivity). Also shown are the average corrosion rates for steel; a similar behaviour can be expected for copper.
- *Porosity*: The porosity of the soil determines the amount of oxygen and water that reaches the metal surface. The corrosion rate for copper is dramatically increased in the presence of oxygen.
- *pH*: Another indicator of the corrosivity of soil is its pH. Extremely acid (pH below 4.5) or alkaline soils (pH above 9.1) can be particularly more corrosive than more neutral ones.
- *Sulphides and chlorides*: Under normal conditions, copper has an acceptable performance when buried. The oxidation layer of copper oxides, formed at the surface of the metal, acts as a protective barrier impeding further corrosion of the underlying metal. Nevertheless, with the presence of sulphide, the products of corrosion are copper sulphides, which are non protective and the corrosion process keeps attacking the metal. In addition, chloride is a “universal” enemy of metals because it reacts and destroys the surface layers formed, accelerating the corrosion process.

TABLE 2: Relationship between resistivity and corrosivity of surface soils for pH>6
(Wranglén, 1972)

Soil resistivity [Ωm]	Salt content [mg/l]	Corrosivity	Average corrosion rate for steel [$\mu\text{m}/\text{year}$]
$<10^2$	<7500	Very high	>100
$10^2 - 10^3$	$7500 - 750$	High	$100 - 30$
$10^3 - 10^4$	$750 - 75$	Low	$30 - 4$
$>10^4$	<75	Very low	<4

Many of the conditions mentioned above can be found in the soil of geothermal areas where power plants can be located, and can be detected using relatively simple techniques. If these conditions exist, it is better to consult a corrosion specialist to assist in the selection of the material used for the grounding grid conductors and, depending on the choice of material, determine also if cathodic protection is necessary to protect other steel structures or pipelines. This is of great importance if we consider that the grounding grid must have a lifetime at least equal to that of the power plant, and that because it is buried, it is difficult to inspect it.

In the Nesjavellir power plant, Iceland, copper ground conductors were used in the grounding grid, buried at a depth of around 0.5 m below surface. Here, the soil is mainly lavas. Buried at this depth, copper seems to be quite protected from H₂S and the performance has been satisfactory.

3.8 Equipment enclosures and cable raceways

Standard metallic outdoor enclosures in geothermal plants will be attacked by hydrogen sulphide, particularly those located on or around the cooling towers, where the non-condensable gas exhaust is usually located. Within a few months or years, the metallic sheet will start corroding until a hole is opened and the gases can reach the devices inside. Regular painting with an epoxy coating system can be of help, but requires more inspection and maintenance. The best approach is to specify corrosion resistant enclosures like NEMA 4X or IP66, which are made of stainless steel or non metallic materials and are adequately gasketed to prevent the ingress of gases. Even though more expensive, these types of enclosures will have a longer life and require less maintenance.

Galvanized steel cable trays can be used indoors without problems. The indoor air is usually fairly dry. However, when installed outdoors, exposed to rain and dew, galvanized steel soon loses its galvanic coating due to the corrosive combination of gases and moisture. Painting the galvanized steel seems to provide adequate protection against this corrosion. Aluminium conduit can be used satisfactorily, except when it is buried, where it will corrode very quickly due to galvanic corrosion. For underground raceways, PVC or polyethylene pipes have commonly been used without problems; the only additional consideration is that, having less mechanical strength than metallic conduits, they have to be buried deeper, typically to a depth of 50 cm, to protect them from damage.

4. H₂S REMOVAL SYSTEMS

In order to limit the exposure of sensitive equipment to H₂S, it is necessary to install some kind of purification system in the plant. These systems are usually found at every modern geothermal power station, but not in all of the older ones. Below are described some of the most common systems in use.

4.1 Air quality control in electrical and control rooms

Control rooms are the nerve systems of a power plant. The accurate control and supervision of the processes depend largely on the proper operation of the control system hardware. On the other hand, the electrical power distribution system provides the power source for most of the process equipment in the plant. Because of the high cost of the equipment and the important losses of money caused by unscheduled shutdowns at a geothermal power plant, the required reliability and availability of control and power distribution systems is very high, and it is important to guarantee that these systems operate in the conditions for which they have been designed, in order to extend to the maximum its useful life and avoid malfunctions. At Nesjavellir geothermal power plant, Iceland, it has been reported that unprotected sensitive electronic equipment like computers typically do not last a year if located in areas with heavily H₂S contaminated outdoor air. In clean air rooms, the same equipment seems to last at least 20 years before failing due to H₂S corrosion. Samples of very fine stranded copper show heavy corrosion after a few years, even in clean air rooms, and the strands become brittle after a few years. Thus, filtering does not provide total protection against H₂S corrosion, but reduces it to a level that multiplies the life expectancy of sensitive electronics.

In 1985 the Instrument Society of America released the standard ISA-S71.04-1985 entitled: "Environmental conditions for process measurement and control systems: Airborne contaminants".

TABLE 3: Classification of reactive environments (Osborne, 1996)

Severity level	Copper reactivity level	Expected equipment reliability
G1 – Mild	<300 A/month	An environment sufficiently well controlled so that corrosion is not a substantial factor in determining equipment reliability.
G2 – Moderate	<1000 A/month	The effects of corrosion are measurable and may be a factor in determining equipment reliability.
G3 – Harsh	<2000 A/month	High probability that corrosive attack will occur.
GX – Severe	≥2000 A/month	Only specially designed and packaged equipment could be expected to survive.

TABLE 4: Severity levels for various corrosive gases (Osborne, 1996)

Contaminant	Gas concentration (ppb)			
	G1 - Mild	G2 - Moderate	G3 - Harsh	G4 – Severe
H ₂ S	< 3	< 10	< 50	≥ 50
SO ₂ , SO ₃	< 10	< 100	< 300	≥ 300
Cl ₂	< 1	< 2	< 10	≥ 10
NO _x	< 50	< 125	< 1,250	≥ 1,250
HF	< 1	< 2	< 10	≥ 10
NH ₃	< 500	< 10,000	< 25,000	≥ 25,000
O ₃	< 2	< 25	< 100	≥ 100

This document provides useful guidelines regarding the effects of airborne contaminants in the corrosion of industrial process instrumentation and control systems. The contaminants are grouped in liquids, solids and gases, and the expected corrosion severity levels are given in relation to the concentration in air of each of these contaminants.

Of particular interest for the purpose of this work is the classification of the reactive environments based on the copper reactivity level, that is, the rate at which a film of corrosion forms on high conductivity copper, in angstroms per month (Table 3). Also, the standard specifies the H₂S concentration in air required to produce each of these severity levels (Table 4). It can be seen that H₂S will cause serious corrosion problems even in the ppb concentration range.

But as this standard suggests, corrosion in electronics not only depends on the presence of corrosive gases but also depends on other factors such as temperature, humidity, dust presence and synergistic effects between different gases.

The temperature of control and electrical distribution rooms has to be controlled because, like many other electrochemical reactions, the corrosion rate increases with increasing temperature. The standard suggests that the corrosion rates could be more than doubled for each 10°C increase in temperature (Figure 13).

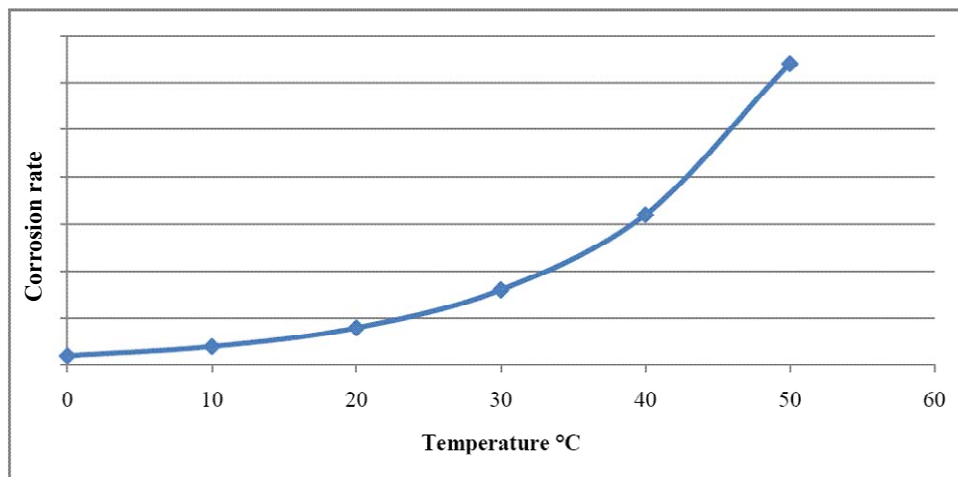


FIGURE 13: Copper corrosion rate can be more than doubled for each 10°C increase in temperature; for illustrative purposes only

Humidity is another factor that has to be closely controlled; it promotes corrosive attack on equipment in three ways:

- Directly, as a reactive chemical attacking metals and plastics;
- Combining with other atmospheric constituents to form more reactive species;
- Dissolving other species to form a conductive solution, which promotes electrolytic or galvanic corrosion between dissimilar metals.

The severity level for a given gas concentration can be expected to increase to the next level for each 10% increase above 50%. Humidity fluctuations are also detrimental in this regard, and the same increase of one severity level can be expected for a relative humidity rate of change greater than 6% per hour. In other words, the relative humidity in control and electrical rooms has to be kept below 50% and fluctuations under 6% per hour. On the contrary, low relative humidity is to be avoided to prevent static build-up and operator discomfort.

Dust is probably the most generalized contaminant. It can contribute to the failure of electronic and electrical equipment in many ways: mechanical, chemical, electrical, thermal or magnetic. Some dust particulates can have high electrical conductivity or adsorb moisture, leading to failure by short circuits. Some particles can have low thermal conductivity, leading to failure by overheating.

Lastly, it has been identified that some corrosive gases acting together can have synergistic effects, i.e., the effect of their combined action is greater than the sum of their effects when occurring separately. An example of this is the synergistic effect of hydrogen sulphide and chlorine (Cl_2), sulphur oxides (SO_2 , SO_3), and nitrogen oxides (NO_x).

4.1.1 Design features of “clean rooms”

Some years ago, the electrical distribution equipment, like motor control centres and medium voltage switchgear, contained almost no electronic components; at that time, the air quality requirements for electrical power distribution rooms were less strict than that required in control, relay and operator rooms. One manufacturer of air purification equipment suggested the following air purity requirements for different types of equipment given in Table 5.

These recommendations have to be taken with some caution. The trend in motor control centres and heavy current switchgear has been to include more electronic devices that perform functions like protection and communication in the power distribution equipment, which means that the previous

TABLE 5: Air purity requirements (Muller, 1999)

Equipment	Air purity requirement
Process computer systems	G1
Microprocessor-based process control or instrumentation systems	G1
Discrete instrument type process control systems (i.e. with separate controllers, indicators and recorders)	G2 at least
Motor control centres (MCC) and substations which contain programmable logic controllers (PLCs), electronic control systems, thyristor drives, or uninterruptable power supplies (UPS)	G2
MCC and substations which contain <i>only</i> heavy current switchgear	G3 approximately (SO ₂ ≤ 200 ppb, H ₂ S ≤ 30 ppb, Cl ₂ ≤ 10 ppb, HF ≤ 10 ppb)

distinctions might, in some cases, no longer be valid. Relays, control system hardware, switchgear, spare parts, and other sensitive electrical and control equipment are usually located inside protected areas. Figure 14 shows the distribution of air-treated areas at the Ohaaki power station in New Zealand.

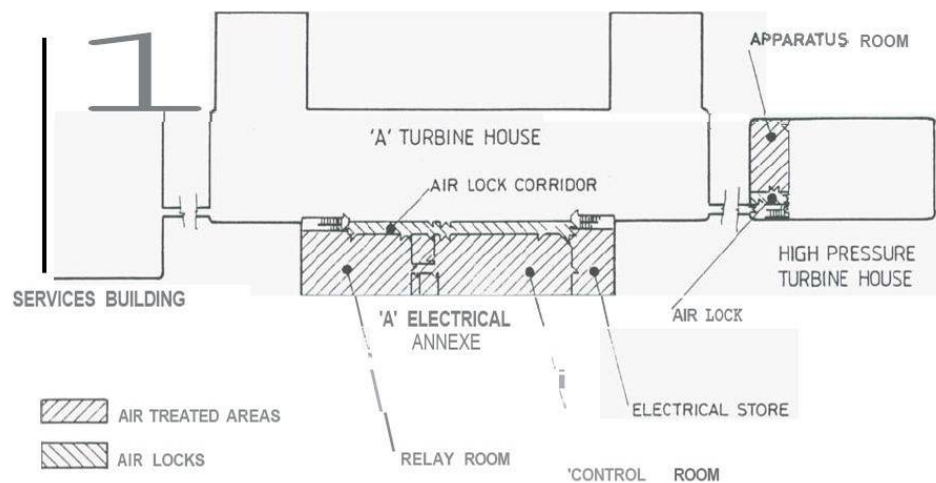


FIGURE 143: Layout of Ohaaki turbine houses (Moore, 1989)

The key aspect to keep in mind with corrosive gas control is to maintain a sufficient flow of clean air into the room to keep it slightly pressurized. By doing this, if there is any small leakage in the room, contaminated air will not flow in, but instead, clean air will flow out. Obviously, the idea is to keep these leakages as small as possible. Regarding this, Osborne (1996) states that “If funds are not allocated to install airlock doors, and to close and seal the multitude of holes and cracks in the walls and ceilings, then do not spend money on air filtration equipment. Instead, set aside the cost of the air filtration equipment to be used for repair of the installed electronic systems. A room that has been sealed will have minimum leakage.”

Based on the results of experimental work carried out in various locations including steel and paper mills, it has been possible to estimate the relationship between room pressurization vs. corrosion rates inside them. It can be seen that a positive pressure of 12-24 Pascals (0.05-0.1” of water) should be maintained in the room (Figure 15); the higher the pressure, the more air flow into the room will be required.

Lendis (2003) discusses some of the construction methods and materials related to the sealing of control and electrical rooms as used in the pulp and paper industry which, as explained above, deal with hydrogen sulphide rich atmospheres. These guidelines, which will be presented have below, are also useful for the design of geothermal power plant rooms.

Walls have to be sealed so that corrosive gas does not permeate through them. Concrete bricks can be coated with block filler, which seals the pores, and low permeability paint. Also glazed tiles or blocks have good performance because of their low-permeability. Wall penetrators can be installed to provide temporary access to hoses or cables inside the rooms. These can be made from steel (3" minimal, schedule 40) or plastic and have to be provided with a cap that closes tightly when not in use. When in use, they have to be sealed with a non-permeable fireproof material to avoid pressure loss.

Doors and windows. Doors have to be sealed to prevent air loss. This is achieved by installing weather-stripping around the perimeter. Strong door closures are required, with a closing force of at least 15 pounds. Airlock entryways are recommended for high traffic areas, like operator rooms, and they should be the main points of ingress and egress; the purpose of airlocks is to prevent sudden pressure loss when the door is opened. A distance of approximately 2.4 m is recommended between the airlock doors. Windows should be limited to viewing and not possible to open; otherwise, proper sealing must be provided.

Penetrations consist typically of conduit, cable tray, air ducts, pipes or structural members entering the building. All of them have to be sealed with fire resistant sealing systems consisting of compounds, caulking or blocks. The end of electrical conduits has to be sealed to prevent air from escaping through them.

4.1.2 Gas-phase air filtration systems

Special equipment is required to remove hydrogen sulphide from the air that pressurizes control and electrical rooms; in some geothermal plants, clean filtrated air is used also for instrumentation air. Equipment performing the function of removing hydrogen sulphide from air that goes into the controlled environment rooms, usually referred to as gas-phase air filtration systems, is typically composed of three stages: a pre-filter section, which removes the coarser dust and contaminant particles and prevents them from clogging the main chemical filtering media; a media containment section, which is filled typically with activated carbon, which removes hydrogen sulphide; and the last stage is a fine filter, which removes the finer dust particles that may have passed the pre-filter (Figures 16 and 17). When an air conditioning system is used to control temperature, it has to work coupled with the filtration system, for it would make no sense to pressurize with clean air if contaminated air is being introduced by the air conditioners. The preferred method is to direct the outside pressurization air through the filtration system and then through the air conditioners, so it crosses the coils. This

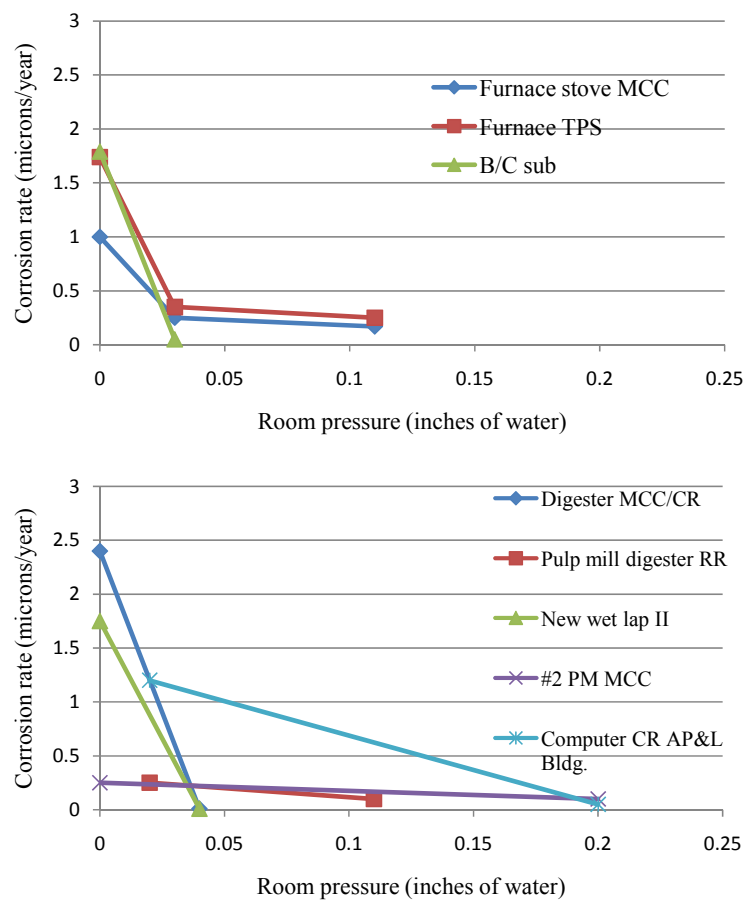


FIGURE 15: Relationship between room pressure and corrosion rates in a steel mill (upper graph) and a paper mill (lower graph) (Lendis, 2003)

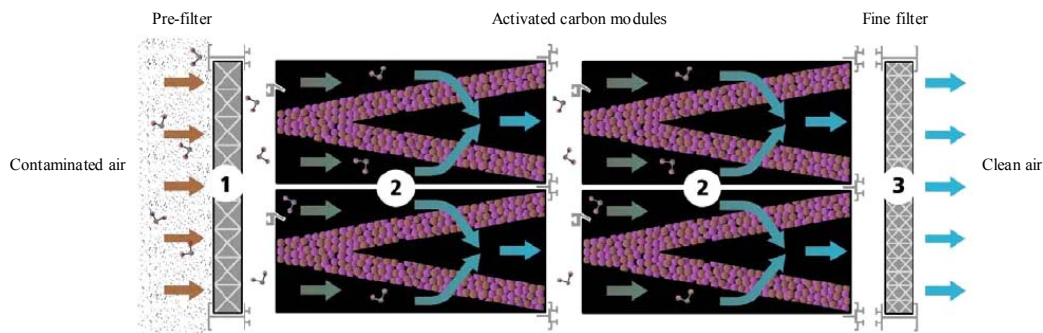


FIGURE 5: Gas-phase filtration for hydrogen sulphide removal (Purafil, 2006a) allows for tempering the outside air as well as protecting the coils (Osborne, 1996).



FIGURE 4: Activated carbon filtration units used in clean rooms at Calpine geothermal power plants, California (Purafil, 2006b)

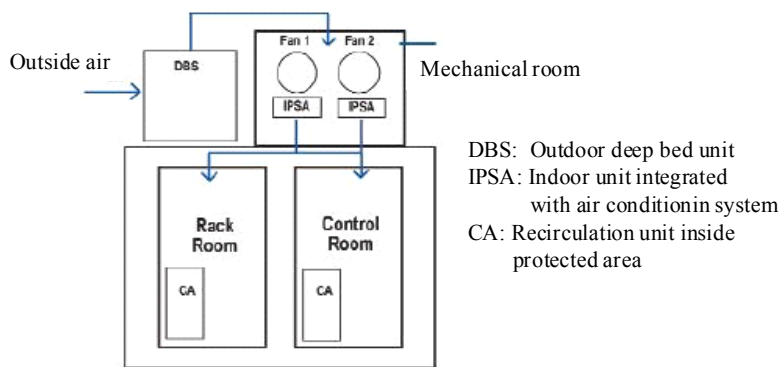


FIGURE 6: H₂S removal system used in a power station with extreme H₂S concentration in outside air

air conditioner integratable equipment as well as integral units that contain the air conditioning equipment themselves are available on the market.

Some manufacturers offer recirculation units, which are self-contained units designed to sit inside the clean air areas to further clean and polish the air by recirculating it through the same filtration media, maintaining very low gas contaminant levels. The configuration of an air treatment system used at a hydro power station with high outdoor levels of H₂S is shown in Figure 18. For independent outdoor panels located outside the main clean rooms, some manufacturers offer small individual pressurization units; those plants that have filtration systems for the instrument air can also use this air to pressurize the outdoor panels.

For outdoor cabinets that contain sensitive electronics such as remote I/O, clean air should be provided from the H₂S filtration system. This can be the instrument air, a separate air system for air tools or even small individual purification units offered by some manufacturer for this particular purpose. The clean air is bled into the cabinets, so that a slight overpressure is maintained inside them. It may be advantageous to have each cabinet split into two parts, one cabinet (or inner cabinet) for the more sensitive electronics. This inner cabinet is rarely opened. The external cabinet has terminal blocks for external wiring etc. (Figure 19).

When considering the location of the filtration system air intake, it is important to consider the fact that some areas in the plant have higher concentrations of hydrogen sulphide than others. This is determined by many factors, like wind direction, relative location to nearby wells, constant steam discharges like pressure control valves, gas exhaust from the turbine condenser vacuum system, etc.

In order to attain a longer interval between activated carbon changes, it is convenient to whenever possible select the air intake from where a lower contaminant gas concentration is expected. The gas exhaust from the vacuum system should be designed and located for minimal gas concentration at the filtration system air intake. It may also be feasible to provide two exhaust locations that can be selectively used based on wind direction. Experience has shown that in a properly designed purification system, the carbon bed should be replaced on an annual basis.

As has been mentioned, a good seal is important for the clean rooms; how good this seal is also determines the size, and as a consequence the cost, of the air filtration equipment. Leaky rooms will require bigger equipment to maintain pressure. Depending on how well the room is sealed, the required air flow rate will be equal to 2-12% of the room air volume per minute; this equals 1.2-7.2 room volume changes per hour, respectively. Computers, electrical and electronic equipment generate a considerable amount of heat when in service. When sizing the air conditioning equipment, it is important to consider the heat generated by the persons inside the room as well as that generated by the electrical equipment.



FIGURE 19: Outdoor pressurized electronic panel with inner cabinet to protect a remote I/O rack at the Nesjavellir power plant, Iceland

It is important to remember that the pressurization air and the leakages are not the only sources of contamination into the room; personnel entering the rooms will carry contaminants on their clothing and shoes. For this reason, it is important to restrict access to these rooms and enter only when necessary; also it is good to keep the floors clean (Osborne, 1996). Another important factor is to make key people in the plant like operators, maintenance and cleaning personnel, aware of the importance of the room sealing and air filtration systems, and the consequences of them being disabled on the equipment inside. Moore (1989) has reported that some problems in this regard have been experienced at the Ohaaki Power Plant, like wedges being put on the room doors for faster access. Another important consideration is that equipment will corrode when hydrogen sulphide is present, regardless of whether the equipment is operating or not; because of this, many of the same precautions taken for control and electrical rooms also apply for electronic spare parts rooms.

4.1.3 Air quality monitoring

In order to obtain information on whether the measures taken to provide a benign environment for electronic and electrical equipment are working properly, it is necessary to monitor various parameters of the air in the clean rooms; otherwise, a failure, malfunction or misuse of any of the sealing or air purification systems might not be noticed until a failure in the protected equipment occurs.

The first two basic parameters to be monitored are temperature and relative humidity; as has been explained above they are important and can be continuously measured using relatively cheap and widely available electronic sensors. Another important parameter to measure is the presence of corrosive gases in the air, which can be typically done in three ways: direct gas measurements, reactivity monitoring coupons, and “real time” corrosion measurements. Direct gas measurement involves the use of an electronic instrument that measures the concentrations in the air of a particular gas, like hydrogen sulphide (Figure 20). They have the capability of detecting concentrations in the ppb range. These instruments can be



FIGURE 20: Portable H₂S analyzer

portable, so that periodic surveys are carried out in different rooms and even different plants with the same instrument 2 to 4 times per month.



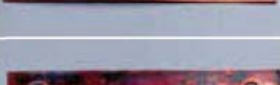

A reactivity monitoring technique is a low cost solution for monitoring the probable corrosion damage in equipment. It consists of locating specially prepared copper coupons inside the protected areas, and exposing them to the same environment to which the electronic and electrical equipment are exposed; corrosion experienced by the coupons would be a good indication of the corrosion that is being experienced by the actual equipment. After placing the samples in the room, they are left for a period of 30-90 days and then sent to a laboratory where the corrosion film thickness is determined. The methodology is explained with detail in ISA-S71.04-1985 (Purafil, n.d.). The standard proposes samples of 15 cm² made from 99.99% pure, oxygen-free, high-conductivity copper as coupon material to monitor corrosion. These coupons are available from companies in the gas-phase filtration market (Figure 21). Table 6 shows the appearance of such coupons exposed to different corrosive levels.



FIGURE 21: Copper and silver coupons for reactivity monitoring (Purafil, n.d.)

TABLE 6: Appearance of copper coupons when exposed to different ISA S71.04-1985 classification environments for 30 days

According to Muller (1999), the main disadvantage to reactivity monitoring using copper coupons is that it does not provide immediate information on the environmental classification, and feedback is obtained after laboratory analysis of the 30-day exposed sample. For this reason, some manufacturers have developed “real time” corrosion measurement systems, which use metal-plated quartz crystal microbalances. Based upon the change within each 24-hour period, the device determines the corresponding 30-day severity level G1, G2, G3 or GX (Figure 22).

ISA Classification	Reactivity rate	Coupon appearance
G1 – Mild	< 300A / 30 days	
G2 – Moderate	< 1000A / 30 days	
G3 – Harsh	< 2000A / 30 days	
GX - Severe	= 2000A / 30 days	

Another monitoring device used at some geothermal power plants is door and window limit switches that give an alarm when a door or a window has been open for a certain amount of time. This prevents excessive entrance of contaminants into the room by alerting the operator when a person leaves a door or

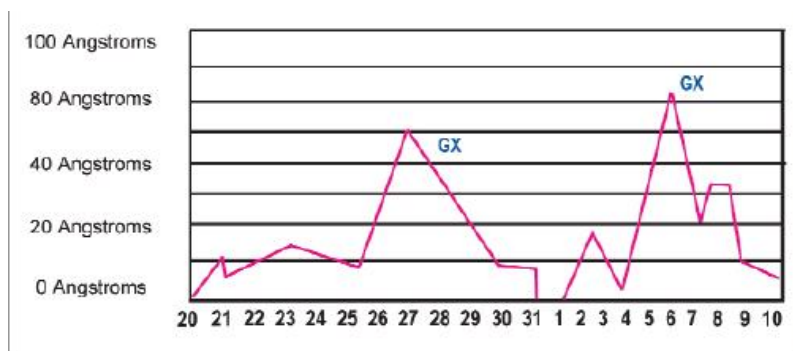


FIGURE 22: Daily corrosion trend obtained using a quartz crystal microbalance device (Purafil, 2006c)

window open. The air filtration system should also be monitored by the plant control system or a separate control system and the operators should be alerted in case of system failure.

4.2 H₂S abatement systems for emissions control

Some countries have strict regulations regarding H₂S emissions from industrial plants, geothermal plants included (Table 7). The plants are required to install additional systems designed to remove H₂S from their emissions, particularly the NCG exhausted normally through the cooling towers, in order to comply with the law and receive a governmental permit to continue operations. Even though some of the main reasons for these regulations are health related, or to avoid complaints from the surrounding communities and to protect nearby tourist sites, there is a side impact on the air quality related to the electrical and control systems of the power plant. The concentrations of H₂S in the air in a power plant with an abatement system can be expected to be substantially lower than in a plant without such a system. As a consequence, a smaller air purification system or no system at all will be required to treat the air into control and electrical rooms. Nevertheless, abatement systems are much more complex and expensive systems, and are not an alternative to the gas-phase filtration systems described above. They are to be considered only when environmental law enforces such action; otherwise, a gas-phase filtration is a more economical solution. Below are described some of the main abatement systems used in geothermal power plants around the world.

TABLE 7: H₂S emissions of some geothermal power plants (Hauksson, 2007)

Plant	H ₂ S emissions per MWh of electricity
Svartsengi, Iceland	1.1 kg
Bulalo, Philippines	1.8 kg
Geysers, USA	2 kg
Ohaaki, New Zealand	7 kg
Krafla, Iceland	9 kg
Námafjall, Iceland	14 kg

4.2.1 Stretford process

One of the first processes used at the Geysers geothermal fields to remove H₂S from the non-condensable gases (NCG) extracted from the condenser was the Stretford process (Figure 23). This is a liquid oxidation process: The gases enter the reactor, where they come in contact with the Stretford solution, which consists of a mixture of sodium carbonate, sodium ammonium polyvanadate and anthraquinone disulfonic acid (ADA). The hydrogen sulphide reacts with the sodium carbonate, and then the resulting sulphide ions react with the vanadium (V), forming vanadium (IV) ions and elemental sulphur, which is floated away as froth. The Stretford solution is then regenerated by injecting oxygen, which oxidizes the vanadium (IV) back to vanadium (V) ions. The ADA is used as an oxygen carrying agent. The overall reaction is as follows:

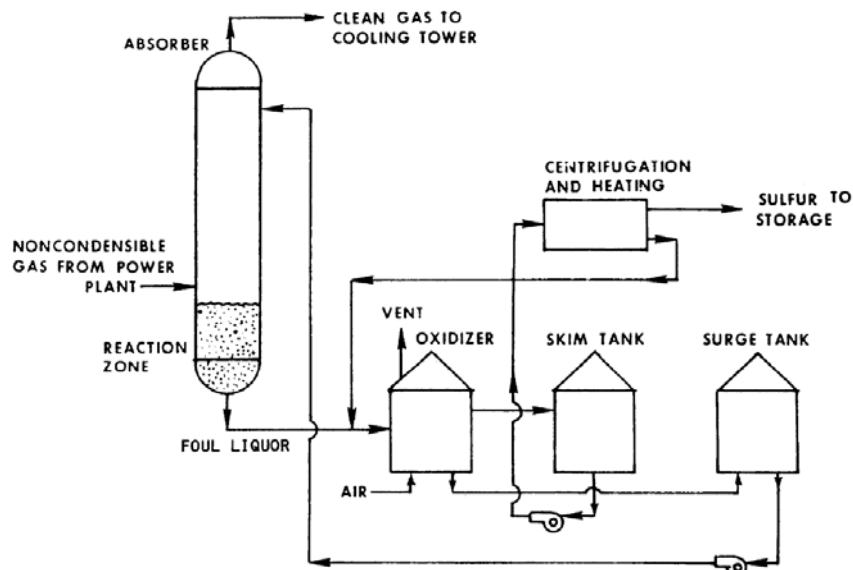
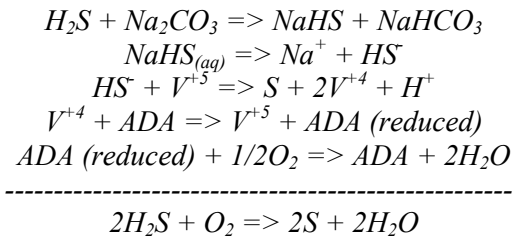


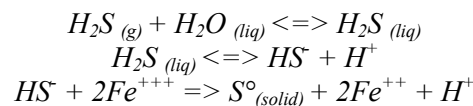
FIGURE 23: The Stretford process for H₂S removal from NCG (Acurex, 1980)



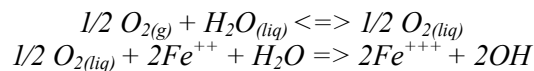
The installation and operation costs of this system are low, but the purity of the sulphur is also low, which reduces its usefulness (Takahashi and Kuragaki, 2000). The removal efficiency of this process can be as high as 99%. An important consideration for this system is the type of condenser used in the power plant.

4.2.2 LO-CAT process

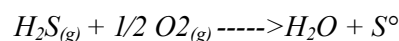
Another common process used to remove H₂S from the NCG is the LO-CAT process. This is another liquid oxidation process where chelated iron is used as a catalyst to convert sulphide ions to elemental sulphur. The first stage of the process is the absorption of H₂S into a slightly alkaline LO-CAT solution; H₂S is ionized to sulphide ions, which is transformed to solid elemental sulphur by reaction with the iron, which is then reduced from ferric to the ferrous state:



Afterwards, the ferrous ion is reoxidized back to its ferric state, regenerating the catalyst and leaving it ready to be used again:



The overall reaction is:



The resultant sulphur slurry is precipitated to the bottom of the vessel, where it is collected (Figure 24). Both of these two processes take place inside the same vessel, separated by baffles, and the driving force for the circulation is the density differences between the aerated liquid in the absorber and the oxidizer. The disadvantage of this process is the large consumption rate of the catalysts, which can lead to high operating costs (Takahashi and Kuragaki, 2000). It is currently being used in geothermal power plants in California, Indonesia and the Philippines.

4.2.3 AMIS Process

AMIS is a patented process invented at ENEL (Italy) in operation at some of their geothermal power plants since 2002, in areas where the smell of H₂S is particularly undesirable because of the touristic character of the place (Figure 25). This process is designed to remove not only H₂S but also mercury from the non-condensable gases (NCG) extracted from the condenser.

The first stage of the process is mercury removal by means of a bed of absorbent material like selenium mass or sulphurized activated carbon; to maximize the efficiency of this process, the gas is previously cooled to a temperature of about 70°C. The second stage of the process is a catalytic oxidation of H₂S to sulphur dioxide (SO₂) in excess oxygen. This requires heating the NCG in order to promote the catalytic effect. The oxidation itself is an exothermic reaction; the gases coming out of

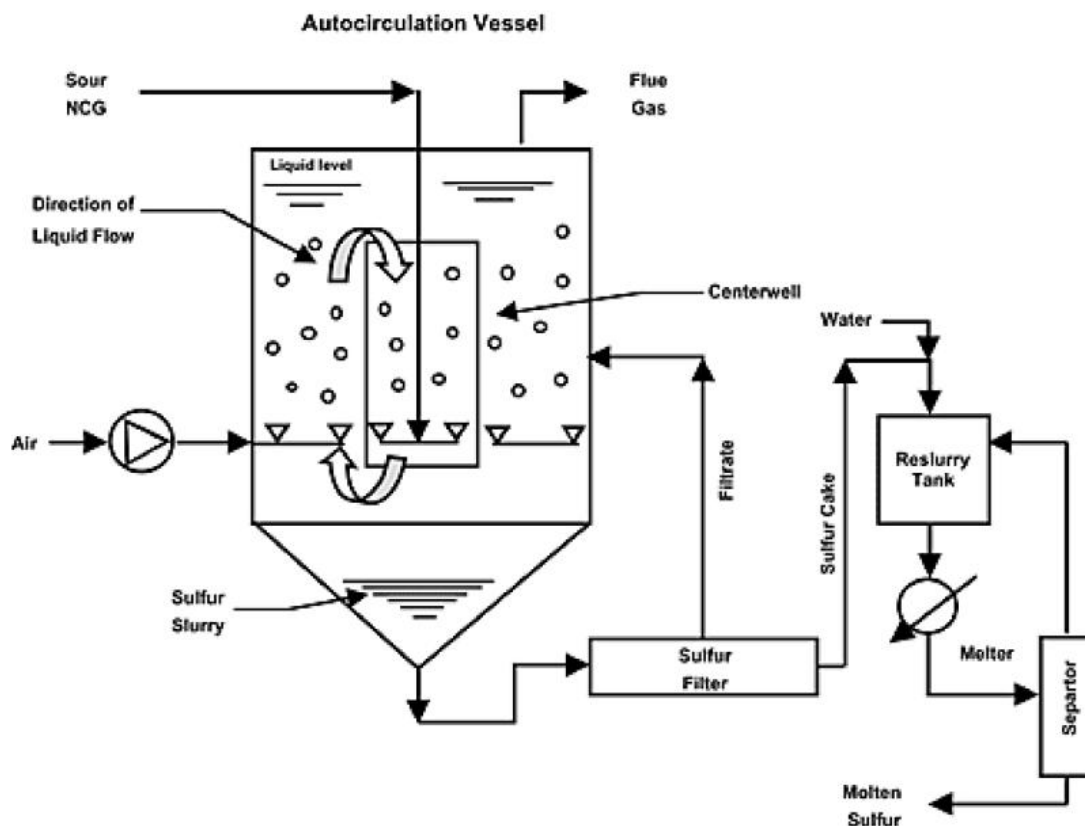
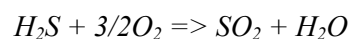


FIGURE 24: LO-CAT autocirculation process (Nagl, 1999)

the reactor are used to preheat the incoming gases in order to achieve the optimal temperature mentioned without the need of an external heat source. The reaction occurring is:



The last stage of the process is scrubbing SO_2 in condensate water coming from the cooling tower basin. This water usually contains basic compounds like ammonia, which react with SO_2 to produce soluble products like sulphites, thiosulphites and thiosulphates. If the water contains enough ammonia, a 100% removal can be achieved; if not, a basic compound like sodium hydroxide (NaOH) can be added to the water to produce the same effect. The water leaving the scrubbing tower is mixed back with the condensate water going to the cooling tower and enters the overflow level control (Figure 26).



FIGURE 25: A picture of the AMIS H_2S abatement system installed at the Travale 4 geothermal power station (IEA, 2006)

4.2.4 Selectox process

Another common method to remove H_2S from a gas stream is the Selectox process, which was installed for the first time in a geothermal power plant at the Yanaizu-Nishiyama plant, Japan, in 1998. In this process, the non-condensable gases are heated to an optimal catalyzation temperature and then

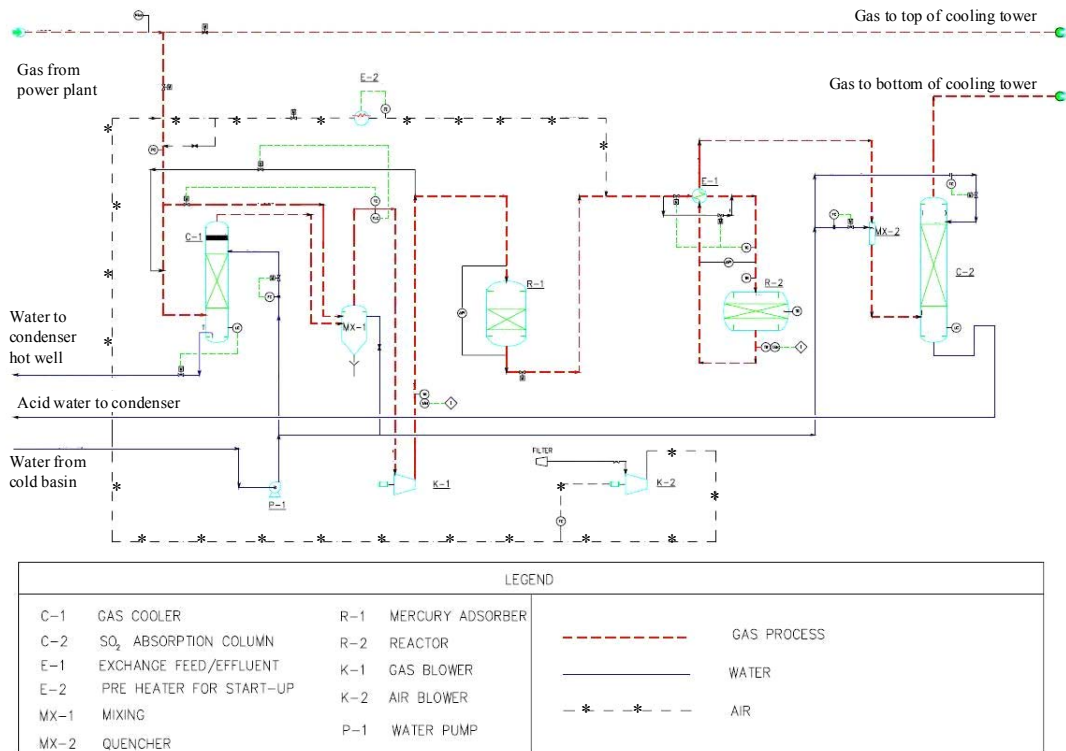


FIGURE 26: AMIS process flow diagram (Baldacci et al., 2005)

enter a reactor, where they react with the Selectox catalyzer, consisting mainly of aluminium oxide and silicon dioxide, to produce SO₂, which in turn reacts with any H₂S which has not reacted yet and undergoes a Claus reaction, producing sulphur vapour. The sulphur vapour is cooled in order to condensate it, and it is collected and transported to a sulphur pit. The remaining gases undergo two more successive similar reaction stages, at the end of which most of the H₂S has been removed (Figure 27). The temperature required at the reheaters is 190°C for the first and second stages and 260°C for the third. Because the temperature of the steam is only 166°C, thermal oil heated by auxiliary heaters was chosen to transfer heat to the gases.

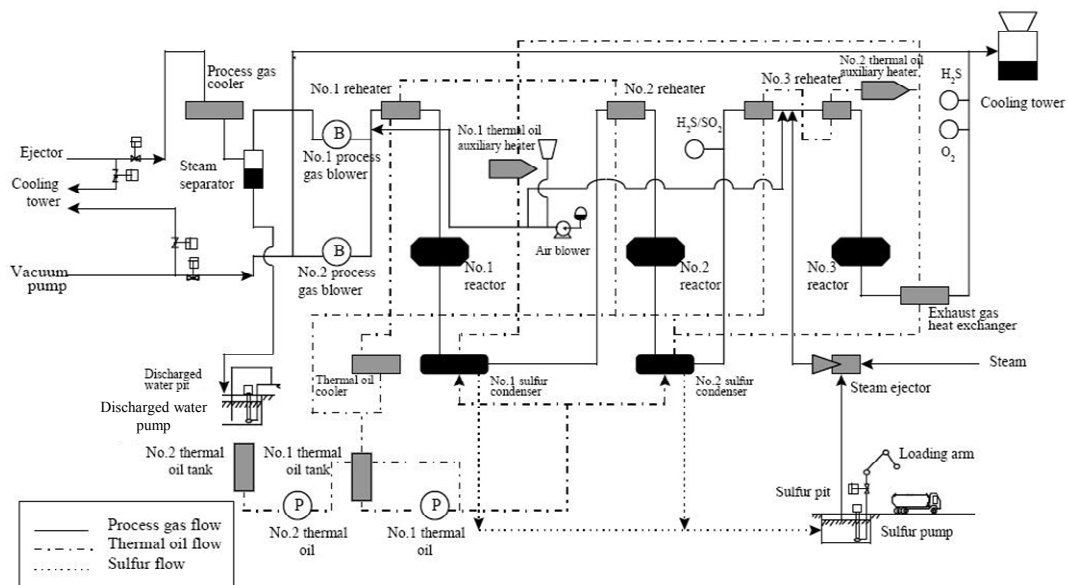


FIGURE 27: Dry-type Selectox H₂S abatement system used at the Yaizu-Nishiyama geothermal power plant. (Takahashi and Kuragaki, 2000)

The produced sulphur is of high purity (more than 99.9%), and is being sold as a by-product, and the performance of the system has been satisfactory (Takahashi and Kuragaki, 2000). It can be seen in Figure 28 that this abatement system is a whole plant by itself, using a considerable amount of space and equipment. This unit produces about 12 tonnes of sulphur by-product per day, with the plant running at 65 MW (Takahashi and Kuragaki, 2000).



FIGURE 28: Picture of the Selectox H₂S abatement system at Yanaizu-Nishiyama, Japan (Takahashi and Kuragaki, 2000)

5. CONSIDERATIONS ON INSTRUMENTATION FOR GEOTHERMAL POWER PLANTS

5.1 Water flow measurement

One of the most problematic applications of water flow measurement is brine measurement, like that used in reinjection systems or brine supply for binary plants. Many geothermal power plants have reported this same problem. At Ahuachapán geothermal power plant, El Salvador, problems have been experienced with averaging pitot (Annubar) flow metering devices (Figure 29) installed at brine reinjection lines. The reason is that the brine is at a temperature close to the silica saturation temperature, which is around 115°C for the fluid in this particular field, and occasionally can be even lower because of mixing with condensate water or water that has cooled in an open emergency tank. The small orifices in the primary element become clogged by silica and sand, and inaccurate readings are obtained. Therefore, the instrument has to be taken out of service to be cleaned approximately once a month, and the cleaning of the orifices can be a difficult task (Figure 30). Also in the Ahuachapán power plant there are annubar flowmeters installed in the brine inlet pipelines to the horizontal flash vessels, but because these lines operate at a higher temperature, 158°C, the scaling is minimal.

In Miravalles 5 binary power plant, Costa Rica, problems with brine flow measurement have been reported (Moya and DiPippo, 2007). The measurements of the specific consumption of brine for the unit seemed to be unrealistic,

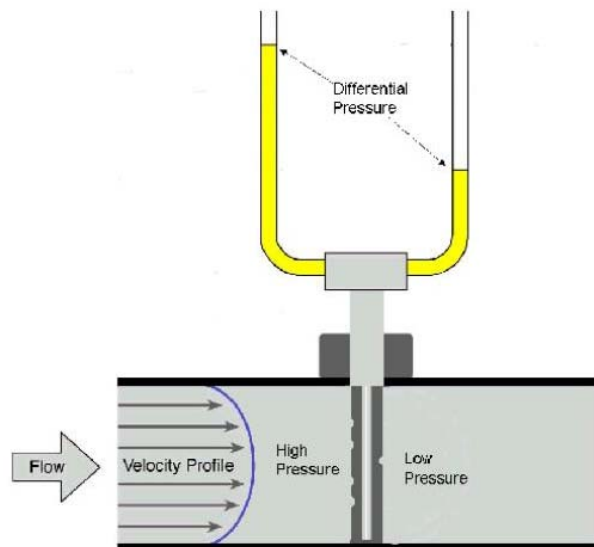


FIGURE 29: The averaging pitot flowmeter (CNSC, 2002)



FIGURE 30: Deposition in the upstream face of an annubar flowmeter in a reinjection line, Ahuachapán

according to the expected performance of the unit, and the reason was found to be that the Annubar element used for measurement was clogged by particulate matter, mainly sand. To address this problem, purge valves were installed in the measurement manifold. The valves are opened periodically to clean the pipe, but the problem with this is that sometimes this valve is left open for extended periods, which distorts the recorded readings, creating confusion when, later, the brine consumption trend is analyzed.



FIGURE 31: Magnetic flowmeter; the flanged instrument becomes an integral part of the pipeline when installed (Siemens, 2007)

In the Palimpinon I geothermal field, Philippines, it was reported (Jordan et al., 2000) that silica deposition caused distortion of the reinjection water flow measurements obtained using an orifice disc.

Magnetic flow meters (Figure 31) are commonly used in Iceland in low-temperature fields exploited for district heating systems with satisfactory performance. They have the advantage of being mostly non-intrusive to the stream, causing almost no pressure drop and with low susceptibility to scaling and abrasion. Disadvantages are that fluid temperature is limited to about 180°C, depending on the manufacturer, and also that because of its installation system it cannot be dismantled with flow in the water line.

5.2 Steam flow measurement

Steam flowrate is a very important parameter, as it serves to calculate performance and efficiency parameters of the power plant. In some operating schemes, one company exploits the geothermal field and sells the steam to the power plant; in such cases, extreme accuracy is required for this parameter.

The most common method to measure steam flow is using differential pressure producers. These elements are inserted in the main flow stream, creating an obstruction which, in turn, generates a pressure loss across it; this differential pressure is used to infer the flowrate. The most common devices used to generate the differential pressure are orifice plates and Venturi tubes (Figure 32). These devices rely on very strict

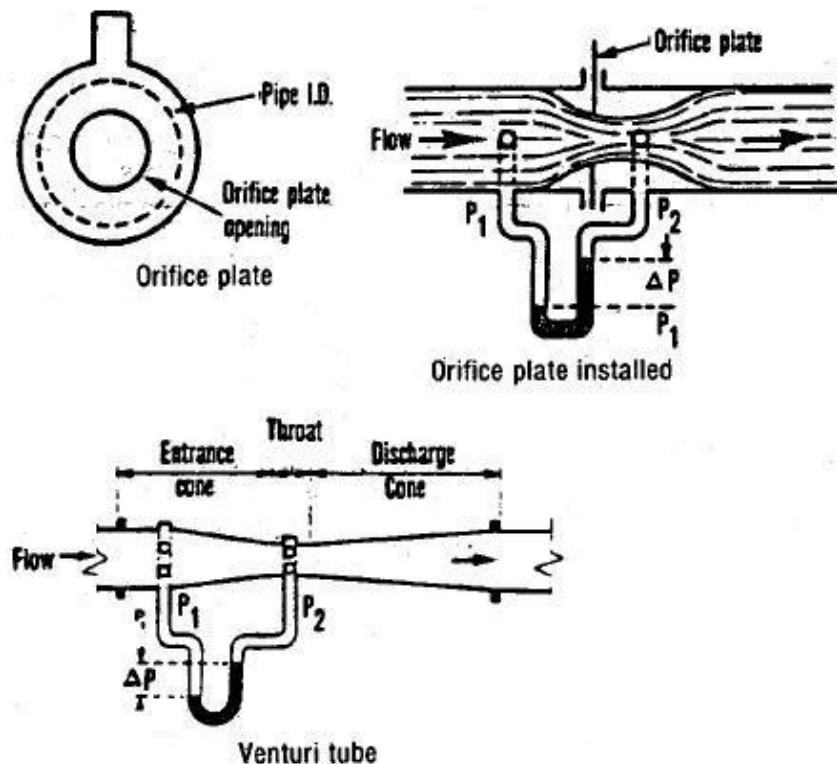


FIGURE 32: Two common differential pressure producers used for flow measurement (modified from Whitbeck et al., 1979)

dimensional and surface roughness tolerances in order to make accurate measurements. The problem with these elements, when used in geothermal steam, is the silica deposition caused by sudden pressure drop. This alters the dimensions, leading to distorted readings. In addition, orifice discs suffer erosion, particularly on the inner edge, causing even more dimensional distortion (Figure 33). For this reason, it is important to keep in mind that these devices will require periodic inspection during plant shutdowns or when readings become suspicious, to check if edges are rounded or the diameter has changed due to scale formation or erosion.



FIGURE 33: Erosion in the inner edge of an orifice disc used to measure steam flow at Cerro Prieto geothermal field, Mexico (Canchola and Sánchez, n.d.)

In recent years, some plants have tried to solve these inconveniences by trying non-traditional instruments like vortex shedding flow meters (Figure 34). The vortex shedding technique consists of the insertion of a bluff body or shedder bar to generate vortices in the flow stream; the frequency of vortex generation is directly proportional to the speed of the fluid. The shedder is subjected to alternating lift forces from the vortices, causing strain in the bar. The frequency of these strain changes is measured using piezoelectric elements. Rouse (2004) reported the use of these instruments to measure the flow of steam at five different geothermal projects in California and Nevada, USA, where problems had been experienced because the orifice plates, venturis and pitot tube arrays were frequently clogged by the large quantities of dissolved solids in the steam. The power station operator reported that monthly maintenance and instrument calibration were unusually not performed. Vortex meters were installed to replace the above mentioned elements, and after two years of service, plant personnel reported that the scaling problems had disappeared, maintenance costs were reduced and the reliability of the measurement had increased.

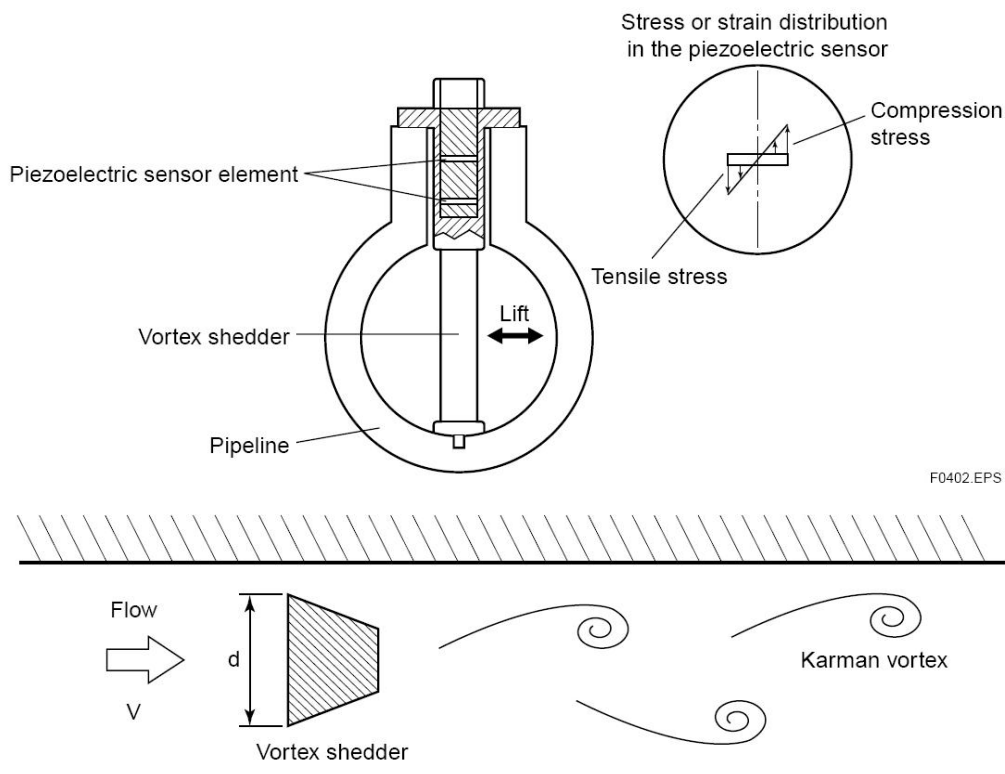


FIGURE 34: The vortex shedding technique to measure steam flow (Yokogawa, 2001)

5.3 Pressure measurement

The most significant problem with pressure measurement in geothermal fluids is deposition which blocks the passage of fluid to an instrument and eventually leads to inaccurate readings. A bourdon-tube pressure gauge will function properly until its inner surface becomes plugged; because the fluid is essentially stagnant, instrument pipes will become scaled. In both cases, the instrument will lose its sensitivity. It is possible to use seals between the geothermal fluid and the instrument, but this does not always solve the problem because, with time, deposition will also occur on the sealing element, degrading the accuracy of the instrument. Periodic purging of the instrument pipes can help to prevent clogging. Another solution is to fill the instrument pipe with clean water or, in places where freezing of the fluid may occur, antifreeze solution instead of geothermal fluid to prevent deposition.

5.4 Water level measurement in pressure vessels

Water level measurement instruments can also be affected by scaling, particularly in pressure vessels containing brine. Differential pressure instruments for analogue level measurement are attacked as described above and, after some time in service, the ball floats become stuck because of silica deposition. This is a dangerous condition, as these level switches are sometimes used for security to provide alarms and turbine trip signals. Moore (1989) reported that higher reliability could be expected from analogue instruments. For this reason, the Ohaaki plant switched to using analogue instruments to set alarms and trip levels. Electrode type level switches seem to have a better performance than float switches in brine service.

5.5 Other considerations regarding instrumentation

Because of the corrosive characteristics of separated fluid or condensate, instrumentation piping is normally stainless steel. Paddle type flow switches are very likely to stick due to silica deposition when in contact with geothermal fluid. These and the above mentioned potential problems must be considered during unit major inspection.

Due to increasing automation in modern geothermal developments, the use of monitoring instrumentation in each well to measure pressure, control electrical valve actuators, etc, is becoming more and more frequent. These instruments are sometimes connected to a central I/O panel via long copper cables, which can be several thousand metres long. In places where lightning activity is frequent, it is a good practice to consider providing surge protectors in each independent circuit of the instruments; otherwise, lightning can produce over-voltages that could destroy the instruments or the I/O cards. An alternative design is to use remote I/O units located near the wells. The remote I/O units should be located in sealed cabinets with clean air leaked into the cabinet. A power supply, which must also be surge protected, is needed for the remote I/O. The remote I/O units are connected through fibre optic cable to a central PLC. This design is less susceptible to damage due to lightning and also permits longer distances between the central PLC and the wells.

For important signals belonging to a control loop, like the steam pressure signal used to control the pressure relief valves, it is a common practice to use a "2 out of 3" voting scheme, in which 3 sensors are used to measure the same parameter and the control system compares the 3 signals, so that it regards a signal as valid only if at least 2 of the 3 signals coincide in value; otherwise, it will consider that at least two of the sensors are faulty and a correct measurement cannot be determined.

The selection of materials for instrumentation piping, pneumatic valve actuators, active parts of instruments, etc., can be made based on the results of a previous materials corrosion testing programme. In this programme, coupons made of various commercially available materials are tested for corrosive behaviour on different geothermal fluids like separated water and steam. Testing must

be carried out before the specifications for the geothermal plant equipment are given. To conduct a program like this, it is necessary to have access to a laboratory with the appropriate equipment and personnel, which might not be the case when a power company is small. In such cases, some smaller companies have opted to relay as much detail as possible about the chemistry of the fluids and environment with which the instruments will have contact in the tender documents, and then leave it to the manufacturers to propose materials according to their experience and expertise, which usually leads to good results.

6. ENVIRONMENTAL REGULATIONS CONCERNING HYDROGEN SULPHIDE

The presence of hydrogen sulphide gas can be easily recognized because of its characteristic smell of rotten eggs. In addition to the corrosion in equipment mentioned above, inhalation can be very unpleasant for humans, and in higher concentrations can cause olfactory paralysation, mucous tissue irritation and even death. Table 8 summarizes the findings from many sources about the effects of hydrogen sulphide in humans, as reported by the World Health Organization (2003).

In a report written by a group of experts and published by the World Health Organization, it was concluded that tolerable concentration for H₂S in air is 100 µg/m³ (71 ppb) for short-term exposure times (1–14 days) and 20 µg/m³ (14 ppb) for medium-term exposure times (up to 90 days) for the protection of humans (WHO, 2003). Some countries have their own air quality standard in which H₂S limits are specified. For example, in Japan, the Offensive Odour Control Law defines a maximum permissible concentration between 0.02 and 0.2 ppm (Japan Ministry of the Environment, 2002); the level of “very weak but identifiable” is 0.006 ppm (Takahashi and Kuragaki, 2000). In New Zealand, the concentration limit has been established at about 0.005 ppm, not with regard to health effects, rather the level at which H₂S starts annoying the population (New Zealand Ministry of the Environment, 2002). In Iceland, the limit exposure is 10 ppm for an 8-hour work shift, but this is currently under revision. In New Mexico and Indonesia, the limit is 0.003 ppm (Hauksson, 2007). The California Ambient Air Quality Standard (CAAQS) establishes that the maximum allowable exposure to hydrogen sulphide is 0.03 ppm for one hour. Moreover, in California the current regulation has established emission limits for power generating plants using geothermal resources, where the maximum emissions allowed are 50 lb/hr released to the atmosphere from a power plant of nominal 100 MW (US DOE, 2003).

TABLE 8: Human health effects at various H₂S concentrations (WHO, 2003)

Symptom	H ₂ S concentration
Odour threshold	8 ppb
Bronchial constriction in asthmatic individuals	2 ppm
Increased eye complaints	4 ppm
Increased blood lactate concentration, decreased skeletal muscle citrate synthase activity, decreased oxygen uptake	5 ppm
Eye irritation	4-21 ppm
Fatigue, loss of appetite, headache, irritability, poor memory, dizziness	20 ppm
Olfactory paralysis	99 ppm
Respiratory distress	560 ppm
Death	497 ppm

7. CONCLUSIONS

Hydrogen sulphide corrosive attack is a problem many industries have to deal with, including geothermal plants. It can damage materials and affect equipment life and plant reliability if not

addressed, but there are well established designs and strategies to deal with it. The key point in these designs and strategies is to select appropriate materials and shelter the equipment which are sensitive, like computers and electronics, from contact with hydrogen sulphide.

In some countries strict regulations regarding H₂S emissions require the installation of abatement systems for H₂S removal and the problem is, thus, solved at the source. In case H₂S emissions to the atmosphere are not limited to an acceptable level, clean rooms are used to isolate sensitive equipment, created by maintaining a positive air pressure inside the room with clean air and providing a good seal at all openings. This clean air is obtained mainly by using gas-phase filtration systems.

It is important to monitor the corrosivity of the atmosphere inside the clean rooms, in order to gain feedback on the performance of these filtration, pressurization and sealing systems. There are many monitoring options available.

Special considerations are also required concerning instrumentation equipment. This equipment is exposed to the particular characteristics of geothermal fluids, and can be attacked in three main ways: corrosion, erosion and scaling. High reliability can be expected from geothermal power plant control, instrumentation and electrical systems if their designs address the particular environment and characteristics of the geothermal fluids, and if maintenance routines include inspections and procedures that take into account the particular modes in which equipment could be attacked at the geothermal power station.

ACKNOWLEDGEMENTS

I want to express my gratitude to the United Nations University and the Government of Iceland for sponsoring and giving me this opportunity to take part in the six months Geothermal Training Programme in Iceland. Special thanks to Dr. Ingvar Fridleifsson, Director of the UNU-GTP and Mr. Lúdvík S. Georgsson, Deputy Director, for their kindness, the passion and patience in their teachings about geothermal and Iceland, and for their warm treatment. My gratitude to my supervisor Mr. Jóhann Thór Magnússon for his useful advice, guidance and comments about my final report. Sincere thanks to Ms. Thórhildur Ísberg, Mrs. Dorthe Holm and Ms. Margrét Jónsdóttir for their useful help and guidance during my stay in Iceland. Thank you Merce for your support and understanding. I want to extend my gratitude to my employer LaGeo for encouraging and giving me the opportunity to attend this course.

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