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Surface vs. Direct Contact Condenser – A Review in Respect to Emission Control in Direct and Flash Steam Geothermal Power Plants in a Stringent Regulatory Landscape

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ABSTRACT

In dry and flash steam geothermal power plants, condenser type significantly influences cold-end system performance, gas emissions, and overall plant sustainability. This paper compares surface condensers (SCs) and direct contact condensers (DCCs), focusing on their respective roles in non-condensable gas (NCG) abatement - particularly hydrogen sulfide (H_2S) - as well as scaling, corrosion, cooling system behavior, and compliance with evolving environmental regulations. It explores how the latest condenser design affects H_2S partitioning between phases and the resulting need for secondary abatement, especially in relation to ammonia content in geothermal steam. Broader considerations such as material selection, oxygen ingress, and potential for biofouling are also addressed, along with the ability of SCs to support combined heat and power (CHP) applications. The analysis demonstrates that no universally optimal condenser type exists; selection must be based on specific site conditions, fluid chemistry, regulatory context, and governing priorities such as commercial and environmental aspects.

1 INTRODUCTION

This paper focuses on the cold-end systems of dry steam and flash steam plants, where condensing exhaust steam and managing residual heat are critical for plant performance and environmental impact. The cold-end typically comprises three main components: the condenser, the cooling system, and the non-condensable gas (NCG) extraction system.

Two main types of water cooled condensers are employed: Surface Condensers (SCs) and Direct Contact Condensers (DCCs). SCs use a shell-and-tube design to separate steam and cooling water, preventing NCG dissolution into condensate, whereas DCCs achieve condensation by directly mixing steam and cooling water.

This paper provides a detailed comparison of surface and direct contact condensers in flash and dry steam geothermal power plants, emphasizing their influence on cold-end performance, non-condensable gas management, emissions control, and fire safety under increasingly stringent environmental regulations.

2 WORKING PRINCIPLE AND STRUCTURAL DESIGN

In general, 2 main principles are to be considered for condensing steam downstream a geothermal steam turbine, surface condensers also called shell & tube condensers and direct contact condensers.

2.1 Surface Condensers

Surface condensers (SCs) operate as shell-and-tube heat exchangers, where exhaust steam condenses on the outer surfaces of water-cooled tubes. This indirect configuration prevents contaminants - such as dissolved solids and non-condensable gases (NCGs) like CO_2 and H_2S -from entering the cooling water circuit. The shell is designed for sub-atmospheric operation, while the tube bundle layout maximizes heat transfer and minimizes pressure drop.

The most important feature with regard to the performance of the condenser is the design of the tube bundle, in particular its shape and air cooler system. The bundle design affects significantly the rate of heat transfer. The bundle exists of heat exchanger tubes connected to tubesheets at the outer ends and supported by baffles to avoid vibration.

Further components of a SC are the water boxes, hotwell and transition piece.

2.2 Direct Contact Condensers

Direct contact condensers (DCCs) condense steam through direct mixing with cooling water, eliminating the need for tube bundles. Cooling water is introduced into the condenser chamber, where it contacts incoming steam, condensing it. The two most common types of DCCs used in geothermal power plants are the barometric and spray/tray condensers. Most variants combine spray nozzles and structured fill packs. Steam initially condenses through contact with sprayed water, then passes through structured packing for additional thin-film condensation.

2.3 Material Selection

Material selection is crucial due to the corrosive nature of geothermal fluids. Stainless steel 316L is widely used in SCs, and DCCs for its resistance to acidic condensate. In harsher environments with high salinity or elevated H_2S levels, duplex stainless steels offer improved resistance to pitting and crevice corrosion (Eliasson et al., n.d.; Penot et al., 2023).

A special case must be made regarding the use of titanium in SCs, particularly in high-salinity environments where seawater is used as the cooling medium. Notable examples include the Nesjavellir and Reykjanes Geothermal Power Plants in Iceland, where SCs incorporate titanium tubing to enhance durability and resist corrosion (Thórhallsson, 1998; Balcke Dürr, 2021). This approach is not applicable to DCCs due to several practical and environmental constraints. The direct contact between cooling water and steam in DCCs promotes scaling, as salts can accumulate and precipitate within the system. In once-through configurations, the condensate cannot be reused, limiting water efficiency. Moreover, discharging the used condensate back into the original water source may raise environmental concerns due to thermal pollution or changes in the chemical composition of the discharge.

3 NON-CONDENSABLE GAS (NCG) MANAGEMENT

Non-condensable gases (NCGs) are a significant byproduct of geothermal power plants, consisting primarily of gases that do not condense into liquid at typical operating temperatures and pressures. These gases are naturally present in geothermal reservoirs and are released alongside steam during electricity generation. Their proportion in geothermal steam varies significantly across different fields, ranging from as low as 0.04% of the average total weight in the Lumut Balai Geothermal Field (Yanto et al., 2022) to as high as 25% (wt) (Gokcen and Yildirim, 2008). Geothermal fields with high concentrations of non-condensable gases, such as Kızıldere where NCG levels can reach 21%, necessitate dedicated systems for gas extraction and utilization (Gokcen and Yildirim, 2008).

The composition of non-condensable gases (NCGs) in geothermal systems is dominated by carbon dioxide (CO_2), which typically makes up around 95% by weight of the total gas content. Hydrogen sulfide (H_2S) is generally the second most abundant component, with concentrations ranging from near zero up to 21% by weight. Other gases-such as hydrogen (H_2), methane (CH_4), ammonia (NH_3), nitrogen (N_2), and argon (Ar)-are present in smaller trace amounts (Khaghani et al., 2013).

3.1 Global Legislation regarding NCGs

3.1.1 H_2S

Over the past decades, regulatory frameworks concerning H_2S emissions have become increasingly stringent. H_2S is primarily regulated based on its distinct rotten egg-like odor. The odor detection threshold varies among individuals but generally falls between 0.03 and 0.05 ppm (California Air Resources Board, n.d.).

International organizations have played a crucial role in establishing exposure limits for H_2S to protect public health and occupational safety. The WHO guidelines recommend an ambient air concentration of 0.007 mg/m^3 (0.005 ppm) averaged over 30 minutes to prevent odor nuisance. For occupational exposure, the WHO suggests a time-weighted average (TWA) of 10 mg/m^3 (7 ppm) over a full work shift and a short-term exposure limit (STEL) of 15 mg/m^3 (10 ppm) over a 10-minute period. These limits aim to mitigate eye and respiratory irritation, which are the earliest recognized toxic effects of H_2S exposure (World Health Organization, 2003).

3.1.2 CO_2

While carbon dioxide (CO_2) emissions from geothermal power plants are significantly lower than those from fossil fuel-based energy generation, geothermal facilities with high non-condensable gas (NCG) content can still contribute notable CO_2 emissions. Fields such as Kızıldere (Turkey) and Larderello (Italy) have been identified as high-CO_2-emitting geothermal sites, primarily due to their elevated NCG concentrations, where CO_2 constitutes

up to 99.8% of the total gas content (Gokcen and Yildirim, 2008). Given the increasing global focus on climate change mitigation, CO_2 regulations for geothermal energy production have become more stringent as well.

In the European Union (EU), geothermal power plants fall under the EU Emissions Trading System (EU ETS), which requires facilities with high CO_2 emissions to purchase carbon credits to offset their environmental impact (EUR-Lex, 2019). Similarly, in California, geothermal plants are subject to the state's cap-and-trade program, ensuring that CO_2 emissions remain within regulated limits (CARB, 2025). These policies reflect a growing recognition that, despite being categorized as a renewable energy source, geothermal power can still produce significant CO_2 emissions, particularly in high-CO_2 fields, necessitating strict monitoring and mitigation strategies.

3.1.3 Other NCGs

Beyond CO_2 and H_2S, other non-condensable gas components-including hydrogen (H_2), methane (CH_4), ammonia (NH_3), nitrogen (N_2), and argon (Ar)-are present in varying concentrations depending on geothermal reservoir characteristics. In some cases, specific NCG components have been of greater regulatory concern than others. For instance, mercury (Hg) emissions have been a significant issue in Italy's geothermal fields, leading to the implementation of the AMIS (Abbattimento Mercurio e Idrogeno Solforato) system to reduce both mercury and H_2S emissions (Zhang et al., 2020). Other NCGs, like CH_4, receive less regulatory attention.

4 DIFFERENCES BETWEEN SURFACE CONDENSERS AND DIRECT CONTACT CONDENSERS IN RESPECT TO USABILITY AND OPERATIONS

4.1 H_2S Partitioning

The choice of condenser type significantly influences hydrogen sulfide (H_2S) partitioning, which refers to the fraction of H_2S that remains in the vapor phase leaving the condenser rather than dissolving into the condensate. In direct-contact condensers (DCCs), the steam directly mixes with the cooling water, allowing a significant portion of H_2S to dissolve into the liquid phase. In contrast, surface condensers maintain physical separation between steam and cooling water, limiting H_2S dissolution and resulting in a greater fraction of H_2S remaining in the vapor phase.

The extent of H_2S partitioning is strongly influenced by the presence of ammonia (NH_3) in the condensate, as NH_3 significantly affects H_2S solubility. Ammonia readily dissolves in water, raising the pH of the cooling water, which in turn enhances H_2S solubility by shifting the chemical equilibrium toward the ionic forms (HS^- and S^{2-}). In systems with low ammonia concentrations ($NH_3/H_2S \ll 1$), dissolution of H_2S in DCCs is between 28–40%, whereas in surface condensers, over 99% of H_2S remains in the vapor phase. Conversely, in systems with high ammonia concentrations ($NH_3/H_2S \geq 1$), 40–70% of H_2S dissolves into the cooling water in DCCs, while in surface condensers, only approximately 20% of H_2S is absorbed into the liquid phase (Weres, 1983; Weres, 1985). Regardless of ammonia concentration, surface condensers consistently exhibit higher H_2S partitioning to the vapor phase compared to DCCs.

When a substantial fraction of H_2S dissolves into the cooling water, the potential for H_2S emissions at the cooling tower is significantly increased. Once the condensate reaches the cooling tower, the cascading action of the water and the induced draft in the tower strip most of the dissolved H_2S out, releasing it into the atmosphere with the cooling tower plume. To mitigate this, secondary abatement systems are often required to chemically treat the cooling water before it enters the cooling tower, preventing the release of H_2S. However, implementing secondary abatement introduces additional capital and operational costs, increases system complexity, and requires additional infrastructure.

In systems with low ammonia concentrations, surface condensers retain most of the H_2S in the vapor phase, resulting in minimal dissolution into the condensate. This typically allows for direct reinjection of the condensate into the geothermal reservoir without requiring prior treatment, thereby reducing abatement costs and operational complexity. However, in cases where ammonia levels are higher, some H_2S may still dissolve into the condensate, increasing the risk of gas breakout, mineral scaling, and corrosion in the reinjection well and reservoir. In such cases, additional measures such as degassing or chemical treatment may be required to stabilize the condensate before reinjection.

4.2 H_2S Abatement

The following analysis is based on the evaluation of process alternatives presented by Sanopoulos and Karabelas (1997), as well as the more recent reassessment by Rodríguez, Harvey, and Ásbjörnsson (2014), who

evaluated non-condensable gas (NCG) abatement strategies using updated performance standards (Sanopoulos and Karabelas, 1997; Rodríguez et al., 2014).

In geothermal power plant design, the selection of the appropriate condenser type is primarily influenced by geothermal steam alkalinity and the chosen abatement process. Ammonia (NH_3) is the key compound affecting alkalinity, as it directly impacts the partitioning of hydrogen sulfide (H_2S) in the vapor phase. This partitioning is a critical factor in determining both the condenser type and the required abatement strategy. When NH_3 levels are low (NH3/H2S $\ll$ 1), a surface condenser can be utilized without the need for secondary abatement. However, at high NH_3 concentrations, a secondary abatement system becomes necessary for both condenser types. In the case of direct contact condensers, the workload of the abatement system will be higher, since the amount of H_2S dissolved in the condensate will be higher as well. Additionally, the evolving composition of non-condensable gases (NCGs) in the geothermal reservoir must be considered, as certain abatement processes are highly sensitive to variations in NH_3 concentration. Another key factor is the required removal efficiency, which may rule out certain abatement methods that might otherwise be viable options. Moreover, the specific characteristics of the geothermal fluid, including its chemical composition and impurity levels, have to be taken into account. Another key factor is environmental impact, as some methods produce byproducts that require additional treatment or disposal.

Despite the complexity of this selection process, extensive research and practical experience have helped identify the most effective abatement strategies based on key criteria such as condenser design, efficiency, geothermal fluid composition, process economics, and operational conditions. Among these, Scrubbing with Alkali, Liquid-Redox Methods, Noncondensable Gas (NCG) Injection, Selectox, Dow-Spec RT-2, and the BIOX Process have been recognized as the most effective, each offering over 90% H_2S removal while presenting distinct advantages and limitations depending on condenser type, geothermal steam composition, and economic feasibility.

Scrubbing with Alkali is a simple method involving scrubbing geothermal steam or non-condensables with a NaOH solution, achieving over 90% H_2S removal. This process can be installed in both types of condensers and is not influenced by geothermal steam composition, making it highly flexible. However, it has low capital costs but relatively high operating expenses due to the continuous consumption of chemicals. This makes it particularly suited for small geothermal units or for temporary abatement during upset conditions. When NH_3 concentrations are high, secondary abatement using the H_2O_2/Iron Chelate Process or Steam Stripping is required.

Liquid-Redox Methods, such as Stretford, Unisulf, LO-CAT II, and SulFerox, are among the most widely used methods, achieving over 99% H_2S removal. These processes convert H_2S into elemental sulfur, which can be collected for disposal or sale. The Stretford process, for example, has been successfully used at The Geysers geothermal field, with over 13 operational units. Unisulf and SulFerox use iron-chelated solutions for H_2S oxidation, offering high absorption efficiencies with low operating costs but requiring high capital investment. These methods operate best with surface condensers and are best suited for large plants. Additionally, when NH_3 concentrations in geothermal fluids are high, secondary abatement with H_2O_2/Iron Chelate or Steam Stripping is necessary.

Noncondensable Gas (NCG) Injection is an alternative that reinjects compressed off-gases mixed with brine into an auxiliary well, effectively removing almost all H_2S from the geothermal fluid. This method was used at the Coso Geothermal Field for nearly seven years, but challenges such as gas breakthrough and corrosion issues led to its replacement with other technologies. NCG Injection shares similarities with liquid-redox methods, requiring a surface condenser and being influenced by NH_3 concentrations. However, its key advantage is its low capital and operating costs, making it a recommended option for large power plants.

Selectox is a process that has been used at the Yanaizu-Nishiyama geothermal power station in Japan. This method combines the Selectox catalyst with a Claus reaction, converting H_2S into solid amorphous sulfur. The process operates in direct contact condenser systems and is suitable for geothermal plants with low ammonia content in the steam. Due to its high complexity, it is recommended for use in relatively large units, as it demands high capital investment but benefits from low operating costs.

The Dow-Spec RT-2 process combines the burner-scrubber method with an iron chelate chemical additive in the circulating water, effectively treating both the off-gas from the NCG system and the condensate in tandem. In this process, H_2S is incinerated to SO_2, which is then scrubbed to form sulfites, and subsequently reacts with sulfur from the iron chelate reaction to form soluble thiosulfates. This method is currently used in Units 5, 6, 7, 8, 11, and 12 at The Geysers, in retrofitted power plants built before 1980. It is designed for plants with direct

contact condensers and is most effective in low-to-medium NH_3 concentration environments. Its operating costs are optimized for large geothermal plants, making it a cost-effective option for high-capacity facilities.

The BIOX process is a downstream abatement method in which off-gases are compressed and mixed with condensate before entering the cooling tower. The process utilizes an oxidizing biocide, which, in combination with oxygen, converts dissolved H_2S into water-soluble sulfates. This method reduces both primary and secondary emissions of hydrogen sulfide from the cooling tower. The BIOX process is currently in operation at the John L. Featherstone Geothermal Power Plant (Hudson Ranch I Geothermal Project). One of its key advantages is its compatibility with both surface and direct contact condensers, as well as its independence from NH_3 concentration levels in the geothermal steam. It has relatively low capital and operating costs, making it a practical choice for both small and large power plants. However, while it provides a cost-effective and flexible solution, its removal efficiency is lower than that of other methods, making it less suitable in cases where near-total H_2S elimination is required.

4.3 Fire Protection Considerations related to Condenser Type

The choice between a surface condenser (SC) and a direct contact condenser (DCC) in geothermal power plants has important implications for fire protection, primarily due to differences in how these systems handle non-condensable gases (NCGs) and the associated ingress of oxygen.

Geothermal steam, by its nature, is typically low in oxygen and nitrogen. However, oxygen and nitrogen can be introduced into the system through various means, forming part of the NCG stream. Common sources of such ingress include vacuum system leaks and the degassing of cooling tower water. While SCs are generally more prone to vacuum leaks than DCCs, the most significant source of oxygen in the NCG stream is the cooling tower, which is associated only with DCC systems (McIntush et al., 2024). In DCCs, oxygen can be entrained in the cooling water and stripped into the steam during condensation, resulting in oxygen concentrations as high as 5–7% in the NCGs. This elevated oxygen content can have serious implications for fire safety (Piggott et al., 2021).

Although geothermal NCGs with added oxygen are not typically explosive under normal conditions, the situation changes when additional gas treatment steps are introduced. When hydrogen sulfide (H_2S) abatement is followed by carbon dioxide (CO_2) capture, the removal of inert gases can concentrate the remaining flammable components and, in the presence of high oxygen levels, create an explosive gas mixture. In contrast, SCs admit less oxygen into the NCG stream, eliminating the risk of forming such a hazardous mixture.

Water injection into geothermal reservoirs, a common practice to maintain reservoir pressure and sustain steam production, can also influence NCG composition over time. As condensed steam is partially lost through the cooling tower, operators often inject cooling tower blowdown and other water sources into the reservoir. Over time, this practice can alter the solubility-driven distribution of gases in the NCG stream. Observations from operational plants have shown a decrease in CO_2 concentrations and H_2S concentrations, alongside an increase in hydrogen content. Despite these shifts in gas composition, the ingress rate of oxygen-primarily from the cooling tower-remains relatively constant, as the circulation rate of cooling water does not change significantly.

This changing ratio of oxygen to combustible gases, especially hydrogen, is critical from a fire protection standpoint. Given hydrogen's wide flammability range, a higher oxygen-to-NCG ratio coupled with an increased hydrogen concentration can push the NCG composition into or near the explosive range. Compounding this risk, reduced overall NCG flow rates (as a result of water injection or gas removal processes) can impact burner performance in systems that combust NCGs. If the gas flow rate falls below the design specifications of the burner, the velocity of gas entering the burner may drop below the flame speed, increasing the risk of flame propagation upstream-commonly known as “burn-back.” This can necessitate costly and complex retrofitting of burners and the installation of safety systems such as flame arrestors and advanced monitoring systems (Piggott et al., 2021).

4.4 Scaling, Corrosion and Fouling

4.4.1 Scaling, Corrosion and Fouling in the Condenser

Geothermal power plants face unique material and operational challenges due to the chemically aggressive and impurity-rich nature of geothermal fluids. Among these, scaling, corrosion, and fouling represent significant operational threats, arising from the complex chemical and physical interactions between geothermal fluids and plant materials or equipment surfaces.

Scaling refers to the formation of hard, adherent mineral deposits resulting from the precipitation of sparingly soluble salts when their ionic concentrations surpass their respective solubility limits. Commonly encountered

scaling types include calcium carbonate, silica and metal-silicates, heavy metal sulfides, and elemental sulfur. These deposits can obstruct flow, reduce heat transfer efficiency, and require costly maintenance and chemical treatment strategies (Boch et al., 2017).

Corrosion involves the chemical degradation and weakening of plant materials, particularly metal components, due to aggressive reactions between geothermal brines and system surfaces. Corrosive species such as hydrogen sulfide, carbon dioxide, ammonia, and chlorides are common in geothermal fluids, and their interactions are further intensified by temperature, pH, and oxygen ingress. Corrosion issues can also be exacerbated by acidification strategies employed to mitigate scaling, often necessitating the use of corrosion inhibitors or the selection of corrosion-resistant materials such as alloys and protective coatings during plant design (Gunnlaugsson et al., 2014).

Fouling refers to the undesirable accumulation of organic and inorganic materials on the internal surfaces of geothermal plant components. Unlike scaling, which typically involves crystalline mineral deposits, fouling often results from the formation of biofilms composed of microbial communities-such as sulfur-oxidizing and sulfate-reducing bacteria-that thrive in the nutrient-rich, warm, and oxygenated environment of cooling towers and condensers. These biofilms introduce thermal resistance to heat exchange surfaces, impairing heat transfer efficiency and increasing turbine backpressure. Additionally, the bio-organic matrix can trap suspended solids, corrosion products, and elemental sulfur, further accelerate deposit buildup and promote under-deposit corrosion or microbiologically induced corrosion (MIC) (Mortensen, 1996).

4.4.2 Scaling, Corrosion and Fouling in the Cold End System

In the cold-end system, the choice of condenser significantly influences corrosion behavior. From a materials perspective, both surface condensers (SCs) and direct contact condensers (DCCs) typically utilize stainless steel to withstand corrosive geothermal environments. However, in high-salinity conditions-particularly where seawater is used as the cooling medium - a special consideration arises regarding the use of titanium in surface condensers. Notable examples include the Nesjavellir and Reykjanes Geothermal Power Plants in Iceland, where surface condensers incorporate titanium tubing to enhance durability and resist corrosion. This practice significantly extends component life under aggressive conditions but has not yet been applied to direct contact condensers (DCCs) (Elíasson et al., 2014).

From a chemical contamination standpoint, although various dissolved substances contribute to corrosion, this discussion will focus on oxygen, whose corrosive impact is closely tied to condenser type.

Dissolved oxygen is one of the most detrimental contaminants in geothermal steam and condensate, playing a key role in accelerating corrosion. While its concentration in geothermal fluids is typically low, its introduction into the cold-end system can have severe consequences. Oxygen promotes the oxidation of hydrogen sulfide (H_2S) in aerated water, resulting in a pH decrease and an increase in overall corrosiveness. Oxygen ingress can lead to a tenfold or greater increase in the uniform corrosion rate of carbon steel. Furthermore, when present alongside chloride ions, oxygen can initiate stress corrosion cracking (SCC), particularly at elevated temperatures (Gunnlaugsson and Einarsson, 1986).

There are two primary pathways by which oxygen enters the cold-end system. The first is through the condenser itself, where vacuum conditions are maintained to enable steam condensation. However, these vacuum conditions can inadvertently draw in non-condensable gases (NCGs)-including atmospheric oxygen-in the event of system leakages. This issue is more significant in surface condensers, which contain a larger number of mechanical joints and components, increasing the likelihood of leakage. In contrast, direct contact condensers feature a simpler construction with fewer potential leakage points, thereby reducing the ingress of atmospheric oxygen (ChemTreat, n.d.).

The second major source of oxygen contamination is the cooling tower. In wet-type, countercurrent cooling towers, the cooling water is exposed to large volumes of atmospheric air. This contact strips volatile gases such as CO_2 and H_2S, promotes oxidation of H_2S into elemental sulfur, sulfites, and sulfates, and enriches the water with oxygen and nitrogen. In DCC systems, this oxygen-rich cooling water is recycled back into the condenser, bringing it into direct contact with the steam or condensate, thus intensifying corrosion risks. In contrast, SC systems maintain a physical separation between the condensate and the cooling water. As a result, even if the condensate becomes oxygen-contaminated, it is generally reinjected into the reservoir without re-entering the plant's circulation, minimizing its corrosive effect on system components (Sigfússon and Gunnarsson, 2001).

In the cold-end system, scaling and fouling are closely interrelated. The dominant concern is the formation and deposition of elemental sulfur. Sulfur primarily originates from the oxidation of hydrogen sulfide (H_2S), either

through chemical reactions with dissolved oxygen or through biological activity involving sulfur-oxidizing bacteria (Kaya et al., 2017; Hidayat and Kuntoaji, 2016). This transformation is highly dependent on pH, temperature, and oxygen availability, and proceeds most rapidly under acidic conditions (Kaya et al., 2017).

In direct contact condensers (DCCs), where steam and cooling water are fully mixed, a higher percentage of H_2S dissolves into the circulating cooling water. As this H_2S-rich water is exposed to atmospheric oxygen in wet-type cooling towers, it undergoes oxidation, leading to the formation of elemental sulfur. This sulfur precipitates within the cooling water system and is transported throughout the loop, contributing to scaling and fouling in components such as spray nozzles, pipes, water distribution plates, cooling tower fill, etc. These deposits impede flow, reduce heat transfer efficiency, and increase condenser backpressure, which can ultimately lead to lower turbine efficiency and reduced power output (Kaya et al., 2017).

In contrast, surface condensers (SCs) maintain a physical separation between steam and cooling water, which significantly limits the dissolution of H_2S into the cooling loop. As a result, the potential for sulfur formation and circulation through the system is lower. However, in SCs, scaling occurs on the external surfaces of condenser tubes, where residual H_2S and oxygen can still react, leading to localized sulfur deposition that reduces heat transfer performance and requires maintenance (Elíasson et al., 2014).

In addition to sulfur scaling, biofouling represents a major operational challenge in geothermal systems using evaporative cooling towers. The warm, nutrient-rich water, combined with the presence of H_2S and sulfur, creates ideal conditions for the growth of sulfur-metabolizing bacteria such as *Thiobacillus* (Hidayat and Kuntoaji, 2016). These organisms oxidize H_2S into sulfuric acid, which causes sharp drops in pH-with recorded values reaching as low as pH 2.0-thereby increasing both corrosivity and fouling potential (Hidayat and Kuntoaji, 2016). The stripping of H_2S in the cooling tower, particularly in DCC systems where the cooling water is already enriched in dissolved H_2S, amplifies the formation of sulfur and promotes microbial activity, exacerbating biofouling throughout the system (Hidayat and Kuntoaji, 2016).

Biocide management is therefore critical but complicated in geothermal cooling water treatment. Many oxidizing biocides, such as sodium hypochlorite, are ineffective in the presence of H_2S, which rapidly consumes the active compound. Several non-oxidizing biocides also fail under these conditions or may interact poorly with dissolved sulfide species. In systems like DCCs, where water turnover is high and cooling water is typically reinjected into the reservoir, biocides must be fast-acting, non-foaming, and environmentally benign. Foaming is particularly problematic in DCCs, as it can cause vacuum instability and turbine trips Mantri, Rodman, and Gill (2019).

4.5 Ressource Utilization & Sustainability – Hot Water Utilization

Special consideration should be given to how surface condensers enable geothermal power plants to produce district heating in addition to generating electricity, rather than solely focusing on power production. Unlike direct contact condensers, which mix steam with cooling water and render heat recovery impractical, surface condensers facilitate the controlled extraction of thermal energy from the steam exiting the turbine. This is achieved by incorporating a segmented design in the surface condenser, where different sections serve distinct purposes. One section cools the steam using conventional cooling water, while another section is specifically dedicated to district heating. In this section, a separate flow of water absorbs heat from the condensing steam before being distributed to the district heating network. This design ensures that a portion of the steam's thermal energy is directly utilized for heating, rather than being dissipated into the environment.

The Hellisheiði Geothermal Power Plant exemplifies the role of surface condensers in combined heat and power (CHP) applications. Located in southwest Iceland, it is one of the largest high-enthalpy geothermal systems in the country. The plant is designed to meet both electricity and hot water demand for district heating. It operates with a total output of 303.3 MWe and 200 MWth, making it the largest geothermal CHP plant in Iceland. (Sigfússon et al., 2023).

The Nesjavellir Geothermal Power Plant follows a similar approach, with an electricity capacity of up to 290 MW (as of 2005) and a district heating capacity of 290 MW. It supplies 1,100 liters per second of 83°C water to Reykjavik's district heating network, providing approximately 4,500 TJ of thermal energy annually. (Lund and Chiasson, 2007).

The Svartsengi Geothermal Power Plant also demonstrates the efficient use of surface condensers for district heating. With a current district heating capacity of >250 MW, the plant supplies hot water to approximately 20,000 people on the Reykjanes Peninsula.

5 DISCUSSION

The comparative analysis of surface and direct contact condensers in dry and flash steam geothermal power plants reveals that neither approach offers universally superior performance. Instead, the optimal selection depends on multiple interrelated factors. Surface condensers offer clear advantages in reducing downstream H_2S emissions-particularly when ammonia concentrations are low-by minimizing dissolution of H_2S into the cooling water. This reduces the need for secondary abatement and supports more straightforward reinjection or disposal of condensate. SCs also limit oxygen ingress, lowering corrosion risks and improving fire safety, while their physical separation of steam and cooling water enables the integration of district heating systems. However, SCs typically involve higher capital costs and greater mechanical complexity, making them more vulnerable to vacuum leaks.

Conversely, direct contact condensers offer simpler construction and lower initial cost, with high condensation efficiency. Yet their susceptibility to oxygen contamination, sulfur scaling, and biofouling - especially in cooling towers - requires more intensive operational management. The associated increase in H_2S dissolution and release necessitates more complex abatement solutions, particularly in systems with elevated ammonia content. Therefore, site-specific geothermal fluid chemistry, regulatory requirements, plant scale, and economic constraints must all be carefully weighed during system design.

6 CONCLUSION

The selection between surface and direct contact condensers in dry and flash steam geothermal power plants carries significant implications for environmental performance, system longevity, and operational efficiency. Surface condensers tend to perform better in terms of emissions control, corrosion prevention, and support for combined heat and power applications, while direct contact condensers offer simpler design and efficient heat transfer. However, the higher potential for H_2S dissolution, oxygen ingress, and scaling in DCC systems necessitates more robust secondary abatement and maintenance strategies. As regulatory pressures around hydrogen sulfide and carbon dioxide emissions continue to intensify, careful condenser selection tailored to site-specific geothermal fluid characteristics and long-term sustainability goals is essential for optimizing performance and minimizing environmental impact.

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