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Predicting and Mitigating Corrosion Related Damage in Geothermal Facilities, Phase-I

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ABSTRACT

Corrosion-related damage (CRD) in geothermal fields is a primary factor which reduces a plant's safety and reliability and hence its profitability. Therefore, to increase the profitability of geothermal power plants, prediction and mitigation of CRD become a high priority. CRD is more prevalent in areas where the steam's early condensate (first moisture) forms. In these areas, active and continuous monitoring of steam corrosivity are not available. The problem is further complicated as the steam condition and its chemistry change with field, seasons, time, injection patterns, and plant load. In response to this problem, an approach was conceptualized with the goal of developing methods and tools for predicting and mitigating CRD of geothermal plant components. In this current work, conditions leading to the SCC of turbine rotor material were evaluated and methods/tools for continuous monitoring of early condensate steam were developed. Finally, a method for mitigating CRD is proposed.

Introduction

Corrosion-related damage (CRD) in geothermal fields is a primary factor which reduces a plant's safety, reliability, maintenance and hence its profitability. CRD can manifest itself in many forms including stress corrosion cracking (SCC), erosion/corrosion (E/C), general corrosion (GC), and corrosion fatigue (CF). Difficulties associated with predicting and mitigating CRD include variations in steam chemistry with field, seasons, injection patterns, plant load, time, and equipment considerations. Furthermore, CRD is more prevalent in areas where the steam's early condensate (first moisture) forms. To increase the profitability of geothermal power plants, prediction and mitigation of CRD becomes a high priority. In response to this need, an approach was conceptualized with the goal of developing methods and tools for predicting and mitigating CRD of geothermal plant components. This paper presents the current Phase I work, where conditions leading to the SCC of turbine rotor material were evaluated and methods/tools for continuous monitoring of early condensate steam were developed.

Objectives

The research project described herein was initiated with support from the Department of Energy, Idaho Operations (Grant #DE-FC07-ID13656). The overall project goal is to increase geothermal plants' profitability by increasing reliability and efficiency of plants and reducing their operation and maintenance costs.

Specific objectives of this current work (Phase I) were the following:

1. Develop an understanding about conditions leading to SCC of the turbine rotor materials operating in The Geysers geothermal field.
2. Develop tools and methods for continuous measurement of the corrosivity of early condensate steam.
3. Propose alternative mitigative solutions to reduce rotor SCC.

Approach

For this project, the following activities were conducted:

SCC Testing in Simulating Steam Conditions in the Turbine Rotor of a Geothermal Plant

A portable field lab, developed earlier [1], was modified and used for simulating early condensate steam conditions in a geothermal power plant. Figure 1 shows the process and instrumentation diagram of this lab. The lab was instrumented with pressure, temperature, and flow meters; a number of modified wedge opening load (MWOL) coupons for measuring crack size; pH and conductivity probes for measurements of bulk steam conditions; and a new device for measuring corrosion potential of early condensate steam.

The lab was initially installed near de-superheating injection ports of The Geysers Unit-20, but later it was moved to the wellhead #GDCF1528. A testing program was implemented in which various parameters were measured continuously. Test-

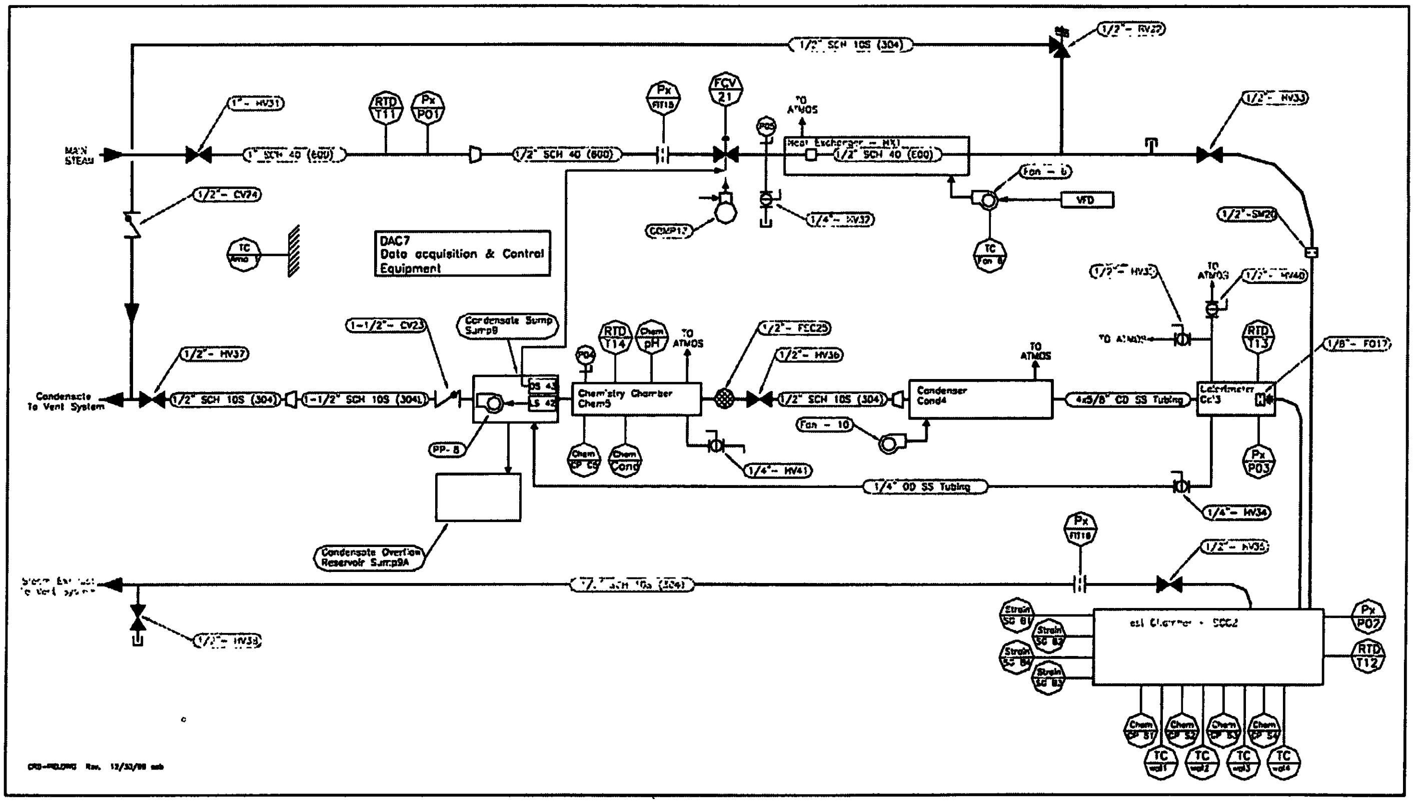

Figure 1. CRD Research Lab P&ID.

ing started in August of 1999 and continued until May of 2000. In addition to lab measurements, steam samples were obtained and analyzed for water vapor, carbon dioxide, hydrogen sulfide, ammonia, argon, nitrogen, methane, hydrogen, chloride, and boron. During this testing program a number of problems (such as failure of lab components and instruments, and power/communication supply issues) were encountered which led to 3 extended lab shutdowns and 11 short duration (1-14 days) shutdowns. However, while these shutdowns were undesirable from economic and scheduling point of view for the testing, they reflect the conditions encountered in real field operation which this testing program was trying to simulate.

As this testing program has not been completed at the time of this paper, a complete data analysis of the results has not yet been performed. However, preliminary evaluation of the collected data shows the following:

1. Steam chemistry measurements indicate a very dynamic steam field where many steam parameters change. For example, Figures 2 and 3 show wellhead chemistries for August '99 to March '00, indicating large variations in these quantities. While the true mechanisms behind the variations in these constituents are not known, injection patterns and plant loads are believed to be important contributors. The steam chemistry data being presented in this paper is for finding their impact on the measured corrosivity of steam and therefore other aspects of this data was not investigated. This information was communicated to the plant owners as it may also be used to investigate causes for variations in steam chemistry.

2. Strain gage measurements during the testing (Figure 4) show small changes in loading, and hence, potentially, the crack size of the MWOL coupons. However, these results are not yet conclusive as these gages failed at various times during testing and the data analysis is not yet complete. Nevertheless, available data suggests crack growth may have occurred under the steam conditions near the wellhead. In addition to performing data analysis, we plan to perform compliance tests of the coupons after completion of the testing program to confirm crack growth.

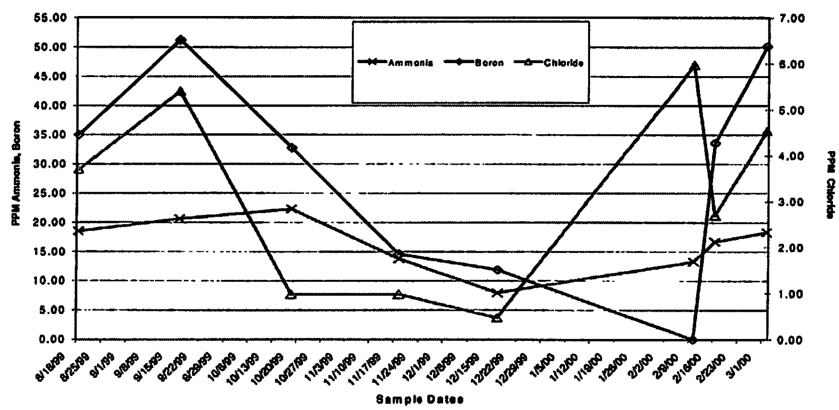

Figure 2. Wellhead chemistry for Ammonia, Boron, and Chlorides.

3. Corrosion potential (CP) measurements (measured by a proprietary probe for the rotor alloy steel) of early condensate steam (see Figure 5) show large variations during testing. Since CP is a measure of corrosivity of steam for a specific material, this result is also indicative of varying steam conditions. It is of interest to note that after each lab shutdown, the CP measurements undergo a large change before settling to their "steady-state" condition. We believe this is caused by introduction of oxygen into the testing chamber during shutdown periods. This may mean that chemistry transients during startup/shutdowns could increase the tendency for CRD of various components.

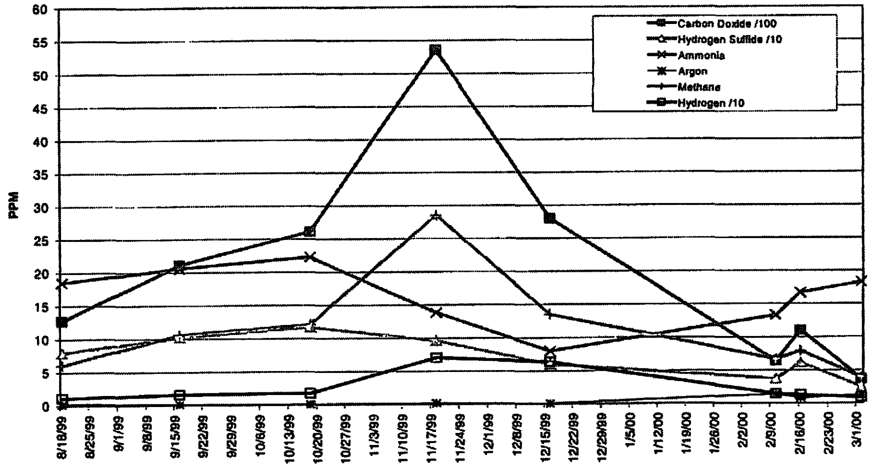

Figure 3. Well head chemistry for Non-Condensable Gases.

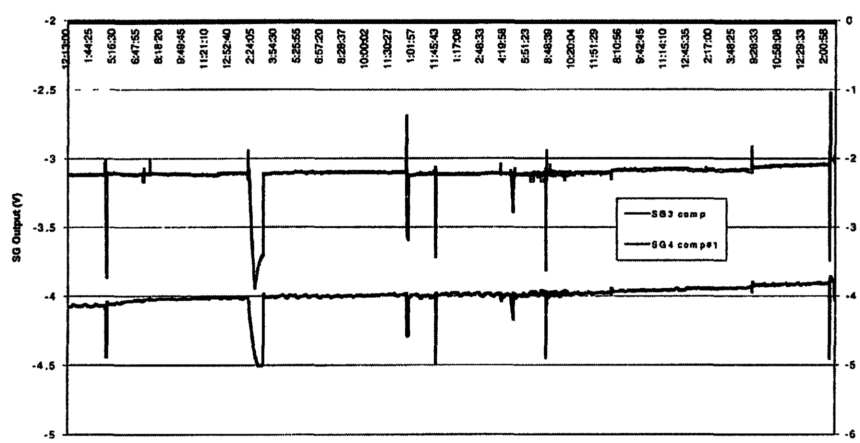

Figure 4. Strain gage data with temperature compensation.

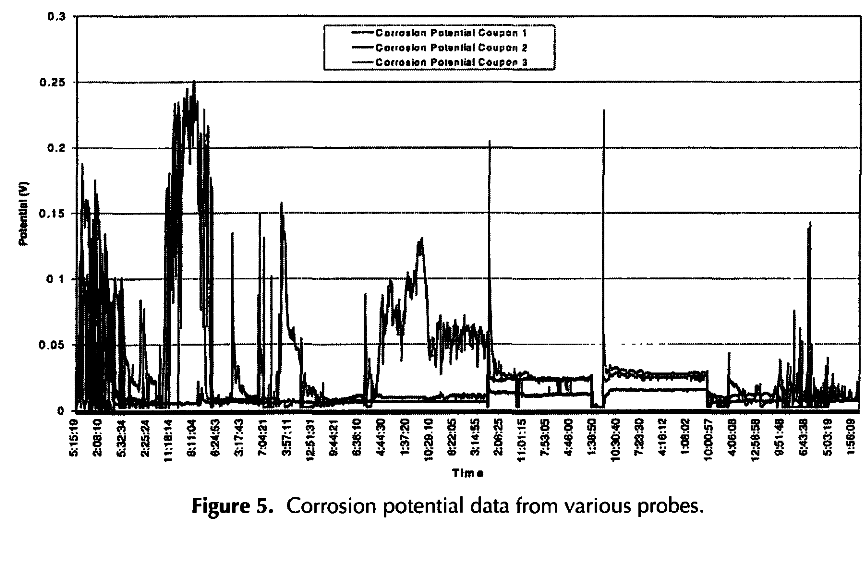

Figure 5. Corrosion potential data from various probes.

Evaluation of Mitigative Alternatives for Preventing SCC

SCC of rotor steel is a costly problem at The Geysers. A method used by the geothermal operators to mitigate this condition is de-superheating. This involves injecting "cold" water into the steam stream to drop it from superheat to moist regime and separating the liquid phase using large separators. This method of "washing" the steam can reduce steam corrosivity significantly. However, this method is very costly (about 2% reduction in generation capacity) and is not fully effective in eliminating rotor SCC. Furthermore, its true benefit and effectiveness cannot be measured as the optimum amount of de-superheating is not known.

Alternatives to the current de-superheating include development of a sealant to protect blade-fit areas, developing dry scrubbing techniques, and adding inhibitors to steam which segregate in the early condensate and reduce the steam corrosivity. The authors are aware of other research projects that are looking into the sealant option (DOE-sponsored) and dry or alternative scrubbing techniques. The authors are not aware of any work to evaluate the effectiveness of inhibitors for mitigation of CRD. As the addition of an inhibitor can provide a very cost-effective solution, it is being proposed here as an alternative mitigative method to eliminate to this problem.

In this approach, an inhibitor, which has been proven to work in geothermal environment, will be selected and added to the superheated steam stream. It is believed that this inhibitor will segregate into the first moisture droplets and hence provide protection against CRD for various components. This solution, if proven, can offer a very low-cost and effective alternative to the current de-superheating and hence increase a plant's profitability. For this purpose, Phase II of the current work, the following needs to be performed:

- Search and identify potential inhibitors which can prevent CRD in the early condensate.

- Design and upgrade the existing lab to allow for testing untreated and treated steam simultaneously.
- Develop and conduct testing to demonstrate the effectiveness of the inhibitor.

Conclusions and Recommendations

This project achieved its objectives by:

- Developing methods and tools and conducting long-term testing for SCC of rotor steel.
- Developing monitoring devices to detect periods where the chemistry of steam's early condensate causes CRD to specific components such that a preventive action can be taken.
- Identifying a new, cost-effective, mitigative solution which can potentially eliminate rotor SCC.

This work concluded that the steam field and its chemistry undergo large changes during operation. Therefore, the need for preventing CRD of various components is not continuous and in fact periods can exist where no preventive measures may be necessary. This work developed tools that can be used to continuously monitor for such changes in the early condensate regime, thus allowing the operators to design and implement an effective and low-cost mitigative approach. For example, these devices/methods can lead to proper de-superheating of steam making sure that over- or under-de-superheating is not taking place.

We recommend that Phase II of this project, where a potential low-cost solution for preventing SCC will be tested for its effectiveness, be implemented. Results of the Phase II work can be implemented on a large-scale to an operating geothermal rotor (Phase III). Future phases of the project, which may involve expanding this technology to other geothermal fields and plant components, are recommended.

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