LOAD OPTIMIZATION BY STEAM AND BLADE WASHING IN A FLASH TYPE POWER PLANT-A CASE STUDY OF OLKARIA II GEO-THERMAL POWER PLANT

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A Thesis Submitted in Partial Fulfilment of the Requirements for the Award of the degree of Master of Science in Geothermal Energy Technology in the Geothermal Energy Training and Research Institute of Dedan Kimathi University of Technology

MARCH, 2019

DECLARATION

Student's Declaration

This thesis is my original work except where due acknowledgement is made in the text, and to the best of my knowledge has not been presented in any university or institution for a degree or for consideration for any certification.

Signature:……………………………………. Date:……………………………………

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G296-003-010/2013

APPROVAL

We confirm that the work reported in this thesis was carried out by the candidate under our supervision as University supervisors.

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DEDICATION

My dedication goes to my family for their support and encouragement which saw me through to this end. I would also like to pass my dedication to the entire KenGen fraternity especially my divisional head, Eng. Abel Rotich for his support during the research process and KenGen PLC, for the financial support inform of scholarship it accorded me for the entire study and research in the Master of Science in Geothermal Energy Technology program.

My final dedication goes to Dedan Kimathi University of Technology for the logistical arrangements, the infrastructure it provided and for the admission it extended to me as one of its students which has turned me to be whom I am today.

To this entire team, I say thank you all and may almighty God shower you with blessings abundantly!

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I also thank my wife for her enormous contributions in terms of material, emotional and financial support throughout the research period. The prayers she continuously made together with our beloved children energised me and gave me the strength to pursue this noble task.

The effort of every other person not mentioned and who has contributed in one way or the other to the success of this thesis is also appreciated.

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ABBREVIATIONS AND ACRONYMS

ADB	Africa Development Bank
CDM	Clean Development Mechanism
CEEC	Centre for Energy Efficiency and Conservation
CER	Certified Emission Reductions
NCG	Non Condensable Gas
DOSHS	Directorate of Occupational Safety and Health Services
EIA	Environmental Impact Assessment
EIR	Environmental Impact Report
EMC	Environmental Management Committee
EMCA	Environmental Management and Co-ordination Act
EMCs	Environmental Monitoring Committees
EMP	Environmental management Programme.
EMS	Environmental management system
EO	Environmental Officer
ERC	Energy Regulatory Commission
TDS	Total Dissolved Solids.
NEMA	National Environmental Management Authority.
DeKut	Dedan Kimathi University Of Technology.
KenGen	Kenya Electricity Generating Company Limited.
Enthalpy	Heat content in a substance in KJ/KG.

SYMBOLS

NCG	Non Condensable Gas
O_2	Compound of Oxygen gas.
CO_2	Carbon dioxide
CO_{2e}	Carbon dioxide equivalent
P, V, T	Pressure, Volume and Temperature
Q	Volumetric flow rate in m^3/s.
T_{Wb}	Wet bulb temperature in Kelvin, K.
T_{db}	Dry bulb temperature in Kelvin, K.
Z	Elevation in meters (m).
SOx	Compound of sulphur and Oxygen.
TDS	Total dissolved solid.
N_2, $H_{2,}$ CH_4	Compounds of Nitrogen, Hydrogen and methane gases.
Na, K, Ca, Mg	Elements of Sodium, potassium, Calcium and Magnesium.
SiO_2	Compound of Silica.
H_2S	Compound of Hydrogen Sulphide gas.
H_2O	Compound of water.
SO_4, $CaCO_3$	Compound of Sulphate and Calcium Carbonate (calcite compound) respectively.
F, Al, Fe, Mn	Elements of Fluoride, Aluminium, Iron and Manganese.
Cl, B, C, As	Chloride, Boron, Carbon and Arsenic elements.
X	Steam dryness fraction ration (or percentage)
h	Enthalpy in KJ/KG saturated steam.
W	Work output in KJ/KG.
$Ca^{2+,}$ Fe^{2+}	Cations of Calcium and Iron respectively.
$HC0_3^{-}$	Bi-Carbonate Iron
$Si(OH)_4$	Silica Hydroxide
e^{-}	Negatively charged electron
$Fe(OH)_3.3H_2O$	Hydrated Iron three Oxide (rust).
$Fe(OH)_2$	Iron Hydroxide.
g	gravitational acceleration m/sec^2
ϕ	Relative Humidity
P_v,	Partial pressure of water vapour
P_{sat}	Partial pressure of saturated water vapour.
m	Mass of a matter, air, water or solid.
ω	Humidity ratio; is the mass of water vapour per unit mass of dry air.
MW	Megawatts Units of measuring electrical energy (Mega Joules/sec).
V	Volume of a vessel in m^3.
Q	Heat load in (W/m^2K).
a	Internal area; Volumetric term for indeterminate transfer area of drops.
dt	Logarithmic mean temperature difference (K)
K	Kelvin; Unit of measuring temperature.
T	Temperature; Hotness or coldness of a substance in degrees centigrade or Kelvin

ABSTRACT

Generator load is the key focus of a power plant which is significantly affected by its generating equipment which can be determined by both maintenance and the running parameters. The parameters of interest for this study were turbine inlet pressure, steam flow rate, steam chest pressure (Bowl pressure) and Generator Loading. The operation of Olkaria II power plant was started in the year 2002, with Unit I turbine taking steam at a flow rate of 62.5 Kg/Sec (225 ton/hr). After operating for 2 years, steam chest pressure increased from 2.5 bar g to 4.1 bar g and steam consumption increased to 72.2 kg/s (260 T/hr.) with the turbine power generation capacity decreased to 26.4 MW out of the rated capacity of 35.0 MW. After dismantling and inspecting for the purpose of this study in 2015 the turbine and its major auxiliary equipment, it was found that significant Sulphur deposition, scaling and related compounds had occurred on the turbine shroud, the turbine nozzles and the cooling tower, reducing their efficiency and leading to reduced power generation. The purpose of this research was to explore blade washing and steam washing operation procedures for removal of silica scaling and deposition at the Turbine blades and nozzles, improving the geothermal power plant efficiency through addressing scales and mineral deposition for improvement of plant performance and productivity. The method employed was the use of steam and blade washing technique. Condensate water is tapped and pumped through spray nozzles to the main steam line while in operation mode (power generation).The pump discharge pressure to the main steam line is 14 bar g and this is above the main steam line pressure of 4.2 bar g. This sprayed water atomizes and increases the density of the steam in the localized area of the main steam line. This mixture then hits the silica deposits around the Turbine blades and nozzles and over a period of time the silica scaling is washed away under pressure. In real time data analysis, the study realized that steam and blade washing have positive effects on load optimization. Once the turbine blade washing was introduced, the steam flow rate needed to generate 1Mwe of power was reduced from a high of 7.9Kg/s to a mean value of 7.24Kg/s. This therefore makes this study conclude that blade washing and steam washing programs improves on turbine efficiency hence optimizes load in a geothermal power plant from silica dominated systems. The research analysis therefore enhances the study of the effects of steam and blade washing on the silica scaling, steam chest pressure, and power plant efficiency.

CHAPTER ONE

INTRODUCTION

This chapter introduces and provides an idea of what is covered in the whole study. It contains background information on sources of naturally occurring geothermal energy around the whole world, what the research seek to solve, research gaps and hypothesis, limitations and assumptions.

1.1 Background of the study

The access to energy is fundamental to our civilization, and our economic and social development fuels a growing demand for reliable, affordable and clean energy of which geothermal energy is part of. Moreover, nearly 1.6 billion people, or roughly a quarter of the world's population, need access to modern energy services (World Energy Council, 2004). However, recent events, including increasing tensions in oil-rich nations and the resulting price volatilities, evolving energy regulations, environmental legislation and diminishing resources call for a balanced energy mix, and maximum effort in the efficient use of available resources. This involves understanding the energy resources, energy generation processes and facilities, and laying down elaborate maintenance strategies for their performance improvement and maximum resource utilization. Kenya has got various energy sources at its disposal. Some are renewable while others are non-renewable. Amongst the non-renewable sources are mainly oil and coal while the renewable sources of energy are mainly Hydro-power, wind, solar, biomass and geothermal energy. Kenya has got a unique energy mix for its grid system. Amongst the various modes of power generations in Kenya's Energy mix (both renewable and non-renewable) are;

1. Hydro-power
2. Oil
3. Coal
4. Geothermal
5. Wind
6. Biomass

Currently as it stands, Geothermal occupies 51% of Kenya's Energy demand although hydro-power energy is more by installation. This is because Geothermal Energy is used as base load and therefore its dispatch is more than any other mode of power generated. The Kenya's global leadership position is 8^{th} the world over in geothermal energy utilisation for power generation. The figure 2.0 below shows our global ranking in terms of world geothermal exploitation and as such the country is likely to overtake Turkey if the construction of Olkaria 1AU units 6 and Olkaria V are completed soon as scheduled.

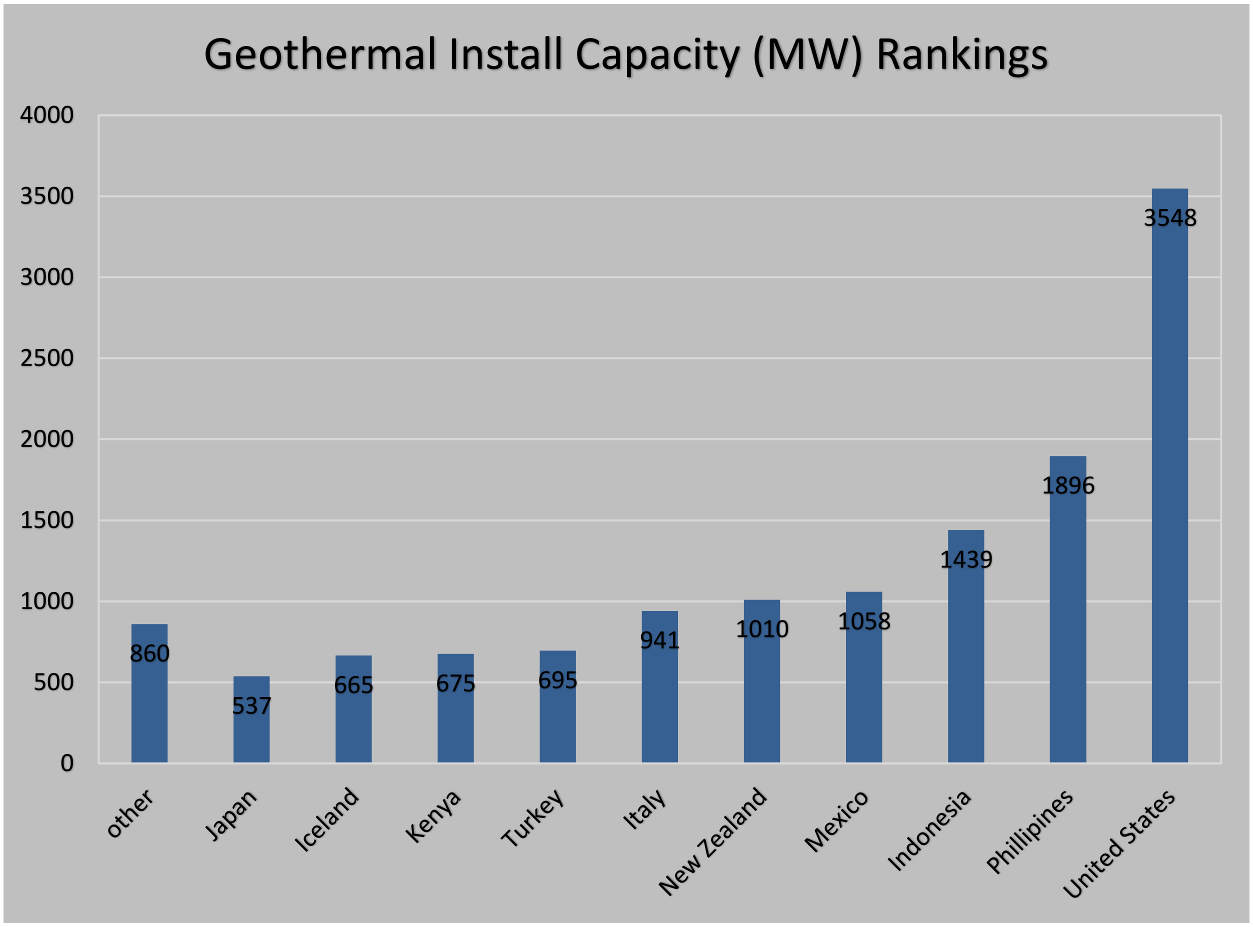


Figure 1. 1: World geothermal installed capacity (MW) Rankings (Geothermal Resource Council, 2018)

Geothermal energy is a naturally occurring phenomenon within the East African Rift valley starting from the afar area (triple junction) stretching to the Mozambique belt. Geothermal energy is energy harnessed from the subsurface emanating around the core of the earth. This energy inform of heat is transmitted by way of conduction and convection through the earth's formation to the surface of the earth. Figure 1.1 below shows the origin of the earth's geothermal energy as heat from the centre of the earth being the core to the upper crust which is the surface of the earth.

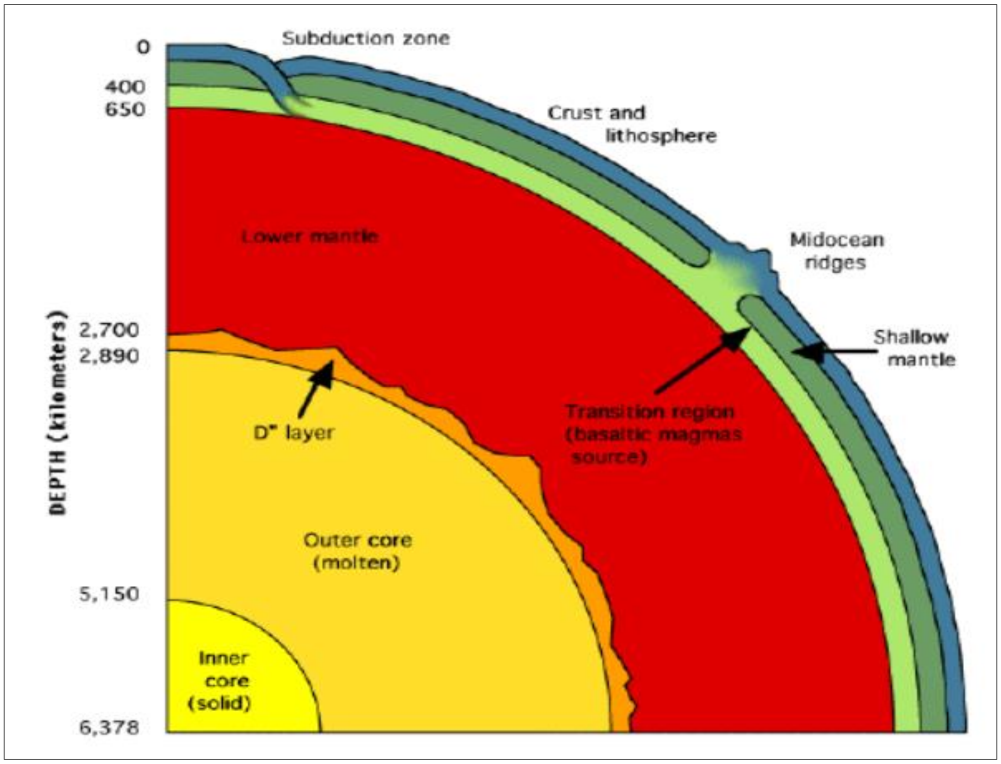


Figure 1. 2: Source of Geothermal Energy from the Earth (source is google search/internet)

The heat energy as it travels to the Earth's surface, heats up the underlying water bodies on its way converting it into steam. The fluid being heated up and trapped between the cap rock and the bedrock underneath builds up enormous amounts of heat and pressure. Whenever this fluid is drilled and brought to the surface, it flashes into more steam after experiencing a sudden drop in pressure. This steam at high pressure and temperature is then directed to a prime mover called a turbine which is then used to generate electricity.

There are several types of deposits which form on the turbine blade causing fouling. One type is that which is apparently caused by a deposition of solids carried in the steam from the steam separators, and another is that caused by a chemical reaction between chemicals in the steam and the material making up the turbine blades. The first type is the most common, and is readily distinguished from the other in that it is largely soluble in water, and is washed off with comparative ease, whereas the other type of deposit adheres to the blades very tenaciously i.e. thermo sets, Ref. "*Deposition of solids in geothermal systems J.S Gudmundsson,D.M.Thomas"* The increase in generating capacity and pressure of individual utility units in the 1960s and 70s, the importance of studying large steam turbine reliability and its efficiency has greatly increased.

The increase in turbine size and changes in design (i.e., larger rotors, discs and longer blades) resulted in increased stresses and vibration problems and enforce the designers to use higher strength of materials. Turbine blades are subjected to very strenuous environments inside a steam turbine. They face high thermal stresses, high impact loading as well as a potentially high vibration environment. The deposition of solids carried in the steam appears to be the major cause of difficulty. This thesis confined itself into getting to know the effect of steam and blade washing on load optimization at Olkaria II power station at Olkaria field in Naivasha-Kenya.

1.2 Background of Olkaria II power station

Olkaria II power station is a 3x35 MW power plant. Units 1 & 2 were commissioned in May and September 2003 respectively while Unit 3 was commissioned in October, 2010. The three Units have performed well since their commissioning with each Unit having generated the followings energy units in Kilowatts hours (kW hrs.) by end of June, 2012: Unit 1 – 2,681,723,134 KWh; Unit 2 – 2,690,394,322 KWh and Unit 3 - 670,828,677 KWh. Figure 1.3 below shows the map of Olkaria field with the location of Olkaria II power plant and the geothermal wells supplying its steam.

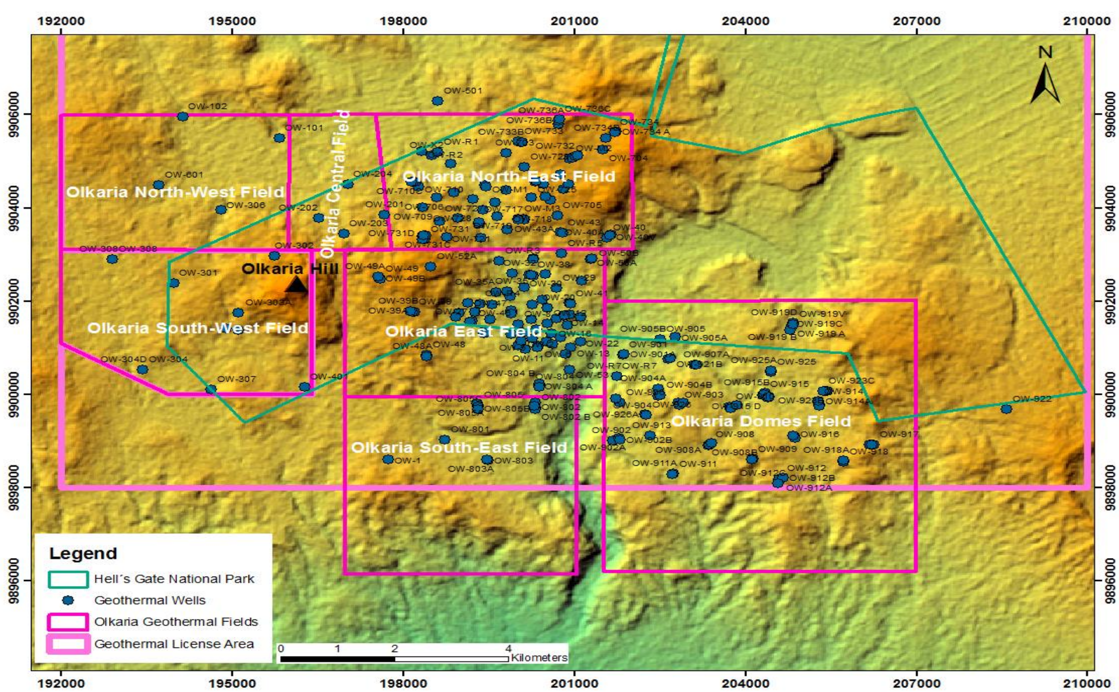


Figure 1. 3: Map of Olkaria field (source is Olkaria well siting committee Mwania et al)

Olkaria II power station is located in a field at about 140 Km North West of the city of Nairobi. The Olkaria field is capable of generating about 1,000 MW of electrical energy. Geothermal steam to Olkaria II Power plant is supplied by 25 wells scattered in the entire Olkaria North East field and the two - phase flow of steam and water is separated at a pressure of 6 bar a in cyclone separators. Brine (hot condensate) is then re-injected into deep hot-reinjection wells located within the field for steam regeneration, while separated steam is passed to the turbine blades at an initial pressure inlet of 4.2 bar g (or 4.8 bar a). Steam at a pressure of 4.8 bar a enters the steam chest then passes through the turbine and exhausts into the main condenser at a pressure of 0.075 bar a, a pressure lower than the atmospheric pressure hence a vacuum.

In the main condenser, turbine exhaust steam and non-condensable gases at 45^o C is sprayed with cold water (condensate) from the cooling tower at a temperature of 21^o C. Exhaust steam condenses to form water (condensate) at a temperature of about 42^o C, which then passes through the hot well pumps to the cooling tower for heat rejection (cooling). In the cooling tower, condensate is cooled from a temperature of 42^o C to 21^o C (depending on the cooling effectiveness of the tower) and passes back to the main condenser by way of gravity for more cooling of turbine exhaust steam. Also, the non-condensable gases (NCGs) coming with steam are ejected from the condenser and pass through the first and second stage steam ejectors (Bernoulli's effect) for cooling and are finally ejected to the cooling tower for dispersion/disposal. A vacuum pump in place helps in ejecting (sucking out) the NCG content that exhausted in the Main condenser after the turbine last stage blade.

The Bernoulli's effect works when a stream of fast moving jet (steam) passes, causing a net effect of creation of partial vacuum along, this causes the non-condensable gases to quickly exit towards this direction to fill this vacuum created hence the ejection! The non-condensable gases then flows in the direction of fast moving steam which leads to their removal from the main system and circulating water by contributing to the Cooling tower plume.

1.3 Major geothermal surface equipment prone to silica attacks

a) Steam Turbine nozzles
b) Main Condenser
c) Hot well pumps and pits
d) Cooling tower nozzles.
e) Cooling tower basins
f) Turbine nozzles
g) Main Steam & auxiliary steam pipelines
h) Re-injection pipelines.
i) Main stop valves and Control valves
j) Steam Ejectors
k) Inter-condensers
l) Brine separators

1.4 Statement of the problem

Geothermal fluids contain varying concentrations of dissolved solids and gases. The dissolved solids and gases often provide highly acidic and corrosive fluids and may induce scaling during well operations. Dissolved gases are normally dominated by CO_2 gas but can also contain significant quantities of H_2S gas, both of which can provide a high risk to personnel and induce failure in drilling tools, casings and wellhead equipment.

Silica scaling is a major problem in most geothermal fields especially in the Olkaria field. The source of steam is from Sulphur and silica dominated reservoirs and this minerals get precipitated whenever flashing occurs mostly in the separators, along steam pipeline, the scrubber vessel and in the steam turbine. The flashing at the steam separators is a physical process of removal of the silica and other minerals contained in the steam through precipitation. The steam is then admitted to the turbine with lesser silica and other minerals content to protect the turbine.

The silica concentration in the flowing steam ought to be mitigated in order to reduce its effects on the power plant during power generation. The kind of scaling that manifests at the power plants equipment is solely dependent on the geology of the formation of the steam field. The scaling reduction can be effected through procedures such as steam washing, blade washing and plant overhauls for manual removal of these scales.

Therefore this project has been developed in order to mitigate on silica scaling and other mineral deposition to reduce their effects on the efficiency of geothermal power plant in Olkaria II power Station. Overhauling and the physical removal of silica from the affected auxiliary components is tiresome and costly, therefore the steam washing exercise is relatively cheap and less laborious and when done well, this yield excellent results within a short turn around period.

1.5 Main Objective

To develop a silica scaling mitigation methodology to enhance plant efficiency in Olkaria II geothermal power plant.

1.6 Specific Objectives

i) Designing a steam and blade washing method as a solution to silica scaling and deposition on the turbine blades and diaphragms.

ii) Designing an experimental steam washing methods for generation of data to be analysed for optimum performance of Olkaria II geothermal power plant.

iii) Optimisation of Olkaria II geothermal power plant by analysis of the experimental data recorded using graphical analytics.

CHAPTER TWO
LITERATURE REVIEW

This chapter provides the review of the theoretical literature, critical review of the study and finally the summary of studies conducted in relation to the problem and the gaps.

2.1 Geothermal Energy Exploration

The Geothermal energy exploration begins with identifying a potential geothermal site that when drilled, the possibility of harnessing useful geothermal steam will be quite high. Geothermal energy utilisation starts with the preliminary surface exploration of studying the geothermal field. This is then followed by drilling of slim holes for exploration purposes. The slim holes play a critical role in collecting data necessary for geothermal study for exploitation. The study depending on the results produced would then lead to the drilling of several production wells to produce steam. The production of geothermal steam for power generation forms the exploitation phase after being passed through separator units for steam separation at higher pressures. The exploration phase of any geothermal activity is a costly and riskier process as one may strike a dry well which would cost anything in the upwards of 5 million United States Dollars.

The Figure 2.0 below illustrates geothermal potential on various sites within the East African rift. For the close to twenty geothermal sites, it is estimated that a geothermal potential of about 10,000 MWe can be realised. The Olkaria field has already harnessed steam that is being utilised in generating electrical energy of about 533.5 MW. The Eburru geothermal field already has a small power plant unit generating about 2.5 MW of electrical energy which was a pilot project that is still working to date.

The Government of Kenya through its exploration arm of the geothermal development company limited is currently focussing on the exploration of the far north areas of the country in Silali, Korosi, Lake Baringo and Paka hills to maximise on the renewable energy project in order to provide its citizenry with not only a cheap source of power but with a clean and renewable source.

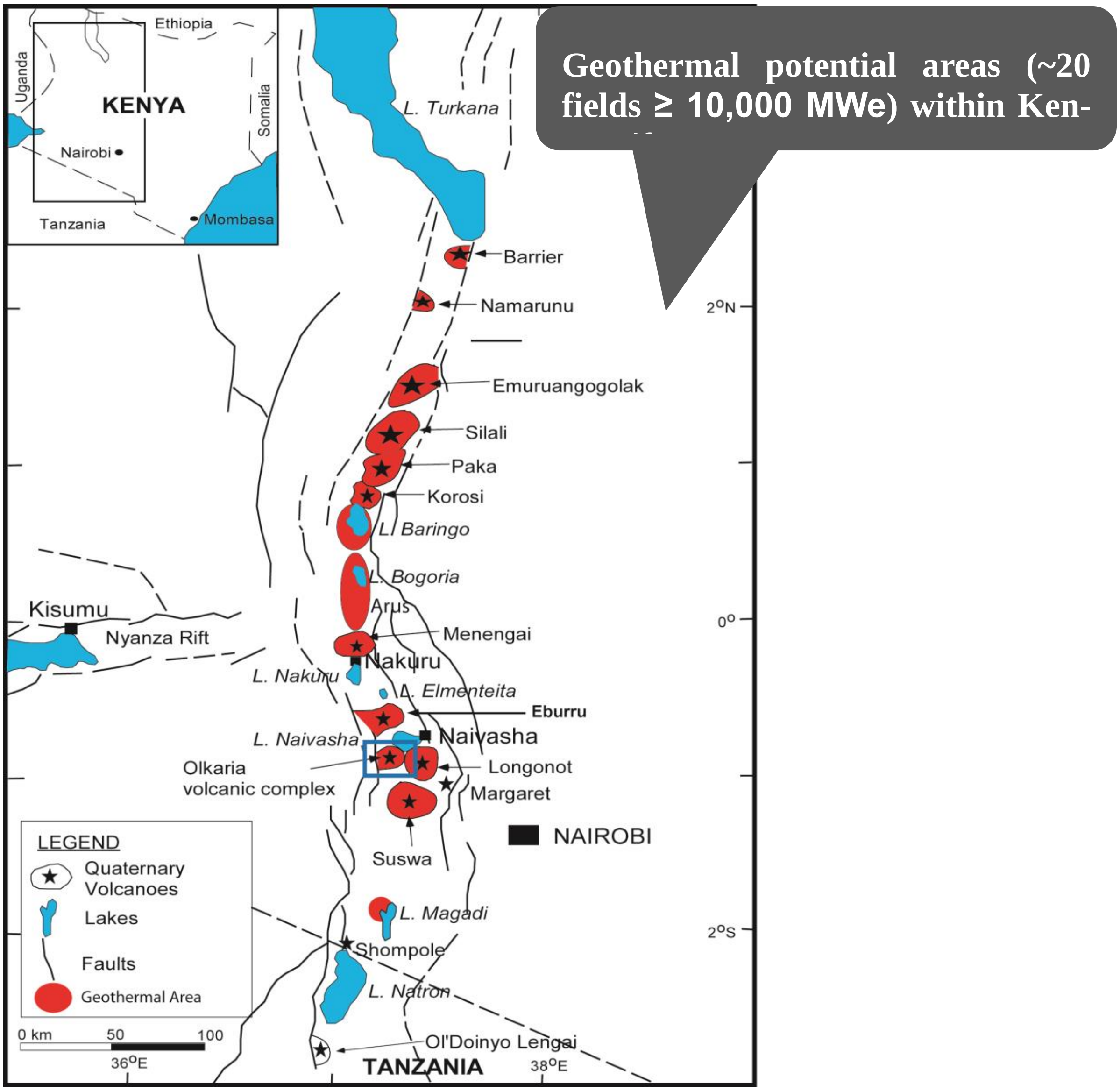


Figure 2. 1: Geothermal potential sites in Kenya today within East African Rift valley.

The exploration phase involves an intensive scientific studies known as the feasibility studies. This is a very crucial phase as it would determine the location of the first production well which would have direct impact on the financiers for the project financing. After a productive well is sited the geo-scientific section then acquires some impetus to carry on with their exploration functions for siting more successful wells for drilling production wells.

Several literature reviews have been developed overtime explaining the phenomenon of silica scaling in geothermal systems. Review of advances on solubility of amorphous silica in aqueous solutions has been made. Relevant literature on effects of temperature, pH, pressure and dissolved salt content on silica solubility has been discussed. Several research reviews on polymerization of amorphous silica over a range of pH, temperature, supersaturation and salinity conditions have been propagated. The existing models for the polymerization rate are summarized and compared. The reports on reaction order and maximum polymerization rate have been contradictory. Lack of solubility and polymerization data at elevated temperature, pH and, especially, in solutions containing multi-component dissolved salts are found to limit advances in current understanding of silica behavior.

In a technical journal paper *"Silica precipitation kinetics: the role of solid surface complexation mechanism integrating the magnesium effects from 25 to 300°C" L.Andre, N.Devau, P.Pedenaud M.Azaroual.* The results presented in this paper allow identifying and integrating the role of magnesium in the kinetic rate of silica precipitation. The basic thermodynamic and kinetic approaches are not sufficient to comprehensively describe the kinetic rate of silica precipitation as well as the simultaneous changes of the solution properties such as pH variations. Trial-error modelling tests reveal that it is necessary to take into account the silica solid surface complexation reactions, in particular the protonation reactions of the silanol sites outcropping of silica surface, in the kinetic law to reproduce measured properties (pH, dissolved silica concentrations, etc.).This newly developed kinetic law is able to correctly describe silica precipitation in presence of magnesium as well as chemical changes in the aqueous phase up to high temperatures (300°C).

In their technical journal paper on "*Research directions in solids deposition in geothermal systems", D.M.Thomas and J.S Gudmundsson* discussed future research directions in the fields of carbonate deposition, silica scale, sulfide deposition, treatment methodologies, heat exchanger engineering, and water/rock reactions. There recommendations for future research included the following: development of more complete and accurate models of the physical and chemical mechanisms associated with the nucleation, adhesion, and growth of scale minerals onto substrate surfaces; investigation and synthesis of more efficient and cost effective chemical scale inhibitors; improvements in heat exchanger materials, design, and operational characteristics; and development of more general economic models for heat extraction facilities that will allow an evaluation of the costs and benefits of various scale-control strategies.

Silica scaling is widely encountered in geothermal wells which produce two-phase geothermal fluid. Silica scaling could be formed due to chemical reaction by mixing a geothermal fluid with other geothermal fluids in different compositions, or also can be caused by changes in fluid properties due to changes in pressure and temperature. One of the methods to overcome silica scaling which occurs around geothermal well is by workover operation. In their technical paper "*mathematical Modelling of Silica Scaling Deposition in Geothermal Wells*", M Nizami[1] and Sutopo[1,2] discussed the finite growth and development of silica scales in geothermal systems.

Modelling of silica deposition in geothermal is an important aspect to determine the depth of silica scaling growth and the best placed method for cleaning silica scaling. Their study attempted to develop a mathematical model for predicting silica scaling growth through geothermal wells. The mathematical model is developed by integrating the solubility-temperature correlation and two-phase pressure drop coupled with wellbore fluid temperature correlation in a production well. The coupled model of two-phase pressure drop and wellbore fluid temperature correlation which they used in their paper is *Hasan-Kabir* correlation. Their mathematical modelling is divided into two categories: single and two phase fluid model. Modelling of silica deposition is constrained in temperature distribution effect through geothermal wells by solubility correlation for silica. The results of their study visualized the growth of silica scaling thickness through geothermal wells in each segment of depth. Sensitivity analysis was applied in several parameters, such as: bottom-hole pressure, temperature, and silica concentrations. Temperature they found out to be the most impact factor for silica scaling through geothermal wellbore and depth of flash point. In flash point, silica scaling thickness reached the maximum because of the reduction of mole in liquid portion.

The Geothermal activities mostly occur along certain defined zones and regions on the earth's surface. Various plates or boundaries provides such zones that easily acts as a heat source for heating the geothermal fluids trapped underneath the earth's surface.

The Figure 2.1 below illustrates the geothermal activity and plate tectonics (movement) around the world. These geothermal activities mostly occur within zones that are active volcanic centres otherwise known as "*the ring of fire"* by the geologists.

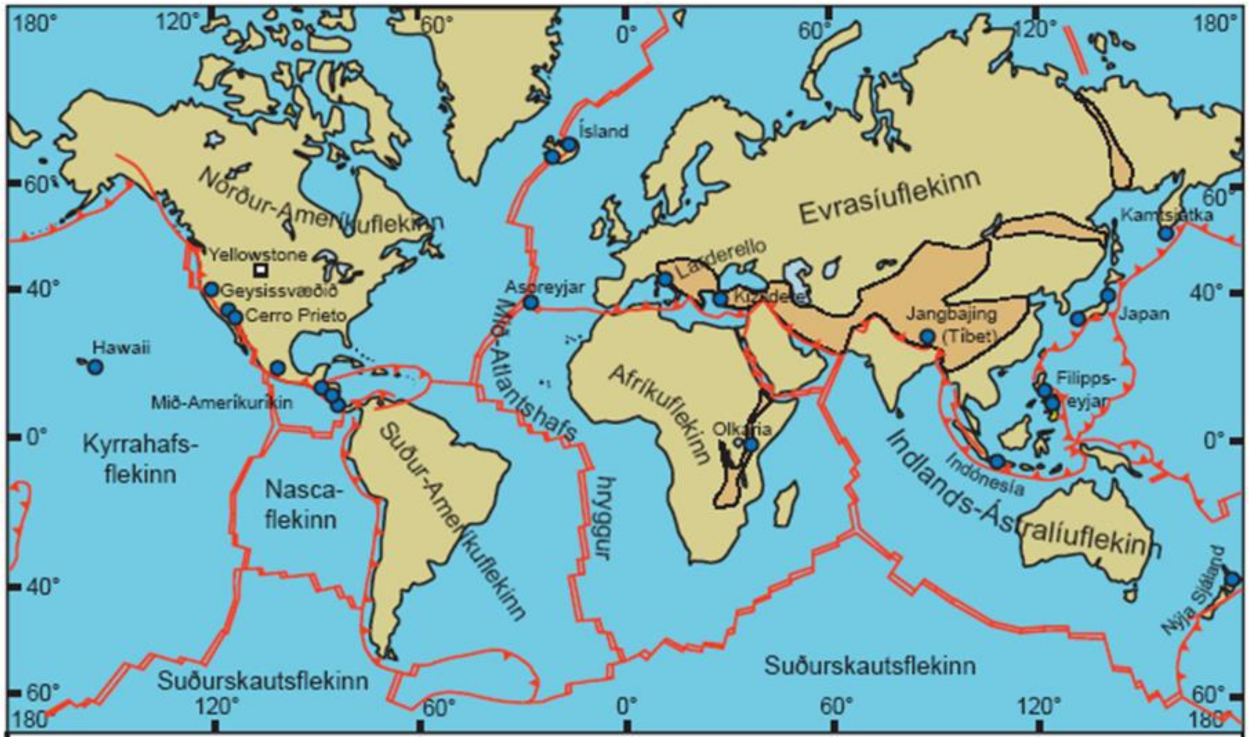


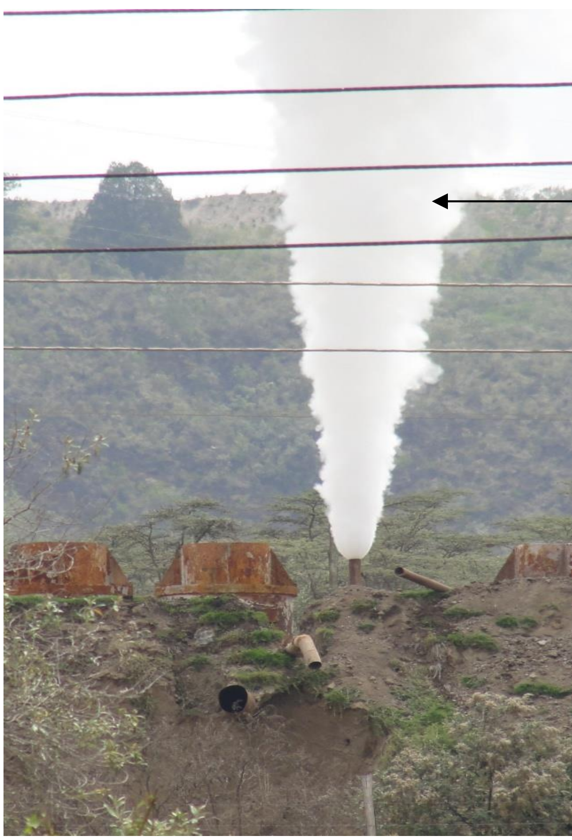
Figure 2. 2: geothermal activity and plate tectonics around the world (Geothermal Resource Council, 2010)

The red boundary clearly indicates high heat sources that is the source of volcanic activity hence geothermal energy source. These localised zones forms the probable areas that plate movements and seismic activities are most likely to occur. When this is below the sea, it causes sea floor spreading. This phenomenon may lead to the formation of the convergent or divergent zones or the occurrence of the Mid-oceanic ridges.

Once a successful exploration activities of a field have been adequately conducted and a possible location of a well has been sited, rigorous production drilling follows for steam production. Drilling is a costly activity that consumes about five million USD (USD 5,000,000) and this is because of the costly drilling infrastructure and materials that goes into it. Some of the drilling materials and equipment needed include the drilling mud (foam), circulating water, diesel generators, the compressors as well as the infrastructure of constructing road networks and the well pads.

There are various types of wells that have been drilled and utilised for different purposes and these wells derive their naming from the various functions that they are meant to serve. Some of the names that have been used to classify the various geothermal wells are;

a) Gradient well
b) Reconnaissance well
c) Exploration well
d) Appraisal well
e) Production well
f) Reinjection well
g) Observation well
h) Step-out well
i) Low temperature well
j) Medium temperature well
k) High temperature well



OW 45 discharging during well testing

Figure 2. 3 : A successful Production well discharging for

Well testing in Olkaria OW 45, Olkaria field in Kenya.

Figure 2.2 above shows OW 45 in the Olkaria field discharging steam and brine during a well completion test. During this period, the production of the well is computed using standard computer software's, computing formulae with simulations.

The steam and brine discharge pressure, temperature and flow rates are computed before being enjoined with the other steam produced from a nearby well in a common steam separator unit in order to calculate the effective production average as it's directed to the power plants.

Figure 2. 4: A successful Production well discharging for well testing in Reykjavik, Iceland

2.2 Geothermal Systems

A geothermal system is one such system that utilises geothermal energy in its functions. A geothermal system may be of a direct or indirect type. The direct type of a geothermal system utilises the geothermal steam in its raw form without converting this type of energy into another form. The steam, brine or complex minerals in brine from a geothermal well is put directly into a more beneficial use. Some of the direct uses of a geothermal system includes;

i. Hot springs heating for bathing in form of Spas.
ii. Green house heating for a quick maturity of the green house plants such as flower farming in Oserian, Kenya.

iii. The use of geothermal steam for the drying of farm produce such as pyrethrum a practice done in Eburru, Kenya by the local community.

iv. Geothermal steam and brine can also be used in fish farming in cold areas to heat the fish ponds in cold seasons a practice that is known to multiply the growth of fish.

v. Geothermal energy can also be used in industries for direct heating and pasteurizing of milk in milk processing plants.

vi. Geothermal energy can also be used in laundries and industrial cleaning where electrical heating can be substituted.

vii. In the cosmetics industries certain minerals with cosmetic value such as sulphur can be harnessed for the manufacture of beauty products.

viii. A variety of minerals can be harnessed from brine as by products. Some of these mineral can be used in industries for other advanced uses.

ix. Some countries like New Zealand, that do experience very severe weather fluctuations thereby experiencing winter are known to be using geothermal energy for direct heating of walk ways and bike riding trucks to avoid the icing. This can also be utilised in heating of runways for aircrafts landing as icing may cause aircrafts skidding during landing and take offs.

x. Geothermal energy can be used directly in the heating and cooling of houses and offices during winter and summer respectively in countries that do experience such weather conditions.

The major indirect utilisation of the geothermal energy is in the generation of electrical energy in running of steam turbines. Geothermal fluids are drilled from various wells and this is then channelled into separator units for the two phase separation of brine and steam. The brine is re-injected back into hot re-injection wells and the steam is made to expand through a prime mover of the type of a steam turbine to generator electrical energy.

2.3 Geothermal power plants

There are three basic types of geothermal power plants;

1) Dry steam plants

The dry steam plants use steam directly from a geothermal reservoir to turn generator turbines. The first geothermal power plant was built in Tuscany in Italy in 1904 where natural steam erupted from the earth.

2) Binary cycle power plants transfer the heat from geothermal hot water to another liquid. The heat causes the second liquid to turn to steam, which is used to turn the steam turbine that is coupled to a generator for generating power.
3) Flash steam plants take high-pressure hot water from deep inside the earth and convert it to steam to drive the generator turbines. When the steam cools, it condenses to water and this is reinjected back to the ground to be used again in the future. Most geothermal power plants around the world are of the flash type.

Figure 2.3 below illustrates a process flow of flash type geothermal power plant in Olkaria II power plant, the most susceptible equipment to silica are the piping just after the wellhead, Separators, scrubbers and within the steam chest pressure at turbine first stage blades and inlet. This equipments form the greatest flashing points along the main steam pipeline and it is here that precipitation takes effect discharging the complex salts in solid forms.

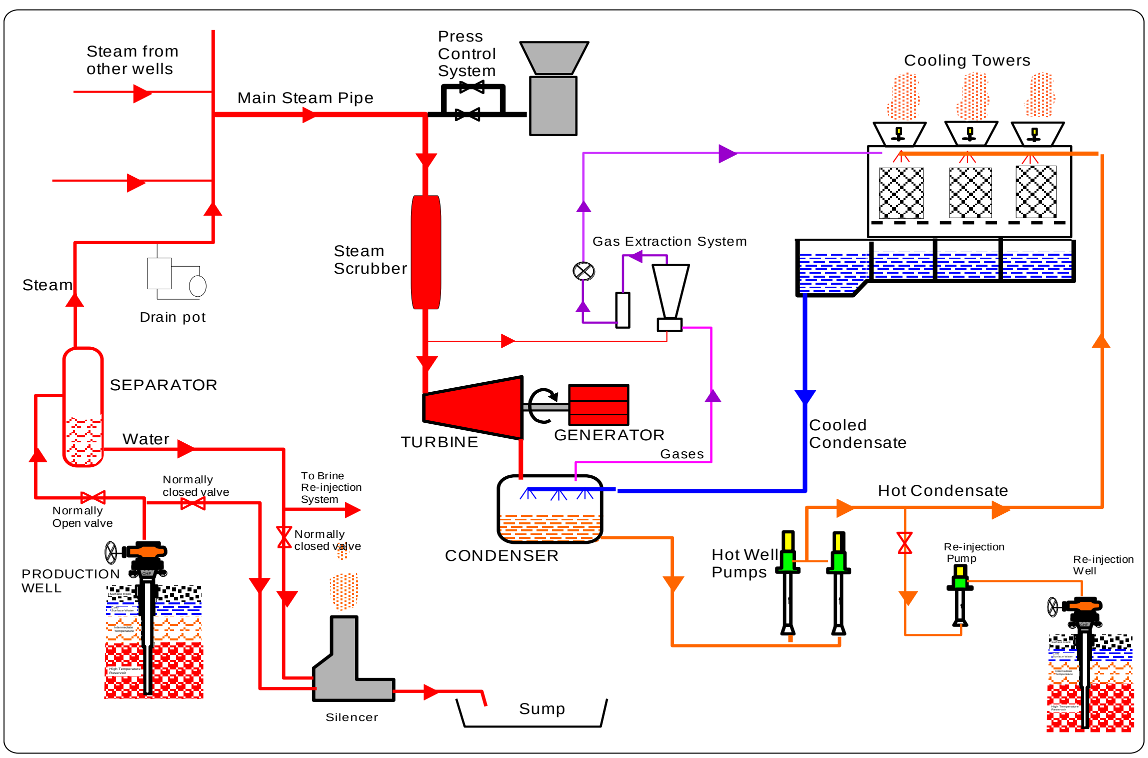


Figure 2. 5: A process flow of flash type geothermal power plant in Olkaria II power plant.

The steam from a production well first flashes with reduced pressure on the surface of the earth. The silica solubility is the highest and it’s supersaturated within a well. This flashing causes a drop in temperature after the pressure drop hence scaling begins to occur as silica precipitates (scales) begins to manifest. This phenomenon is repeated each time flashing occurs all the way to the last stage turbine blade. The silica dissolved in the condensate water which forms the circulating water system and the reinjection water system is carried around and finally finds its way into the re-injection wells. The silica precipitated and deposited onto the surface equipment such as the steam chest pressure and the main steam pipes forms the basis for this project and a serious attempt has been made to provide the solution.

Olkaria II power station receives steam from Olkaria North East field which measures about 6 km2 in area. The field has 25 production wells, 4 hot re- injection wells and 2 cold re-injection wells. In addition to the deep Production and reinjection wells, 3 shallow wells, M1, M2 and M3 were drilled as field monitoring wells but are not currently in use. Furthermore, the field has been divided into eastern and western fields for better operation and steam field management.

The well casing program consists of 20’’ diameter surface casing; 13 3/8’’ anchor casing; 9 5/8’’ production casing, and 7’’ slotted liners. The production casing usually extends to between 600 and 900 m depth while the drilled well depth ranges from 1800 to 2500 m.

2.4 Scaling in Geothermal Systems

Scales are hard mineral coating and corrosion deposits made up of solids and sediments that collect in the distribution systems e.g. piping, storage tanks, reservoir and household plumbing. The plugging and deposit problems caused by scale can reduce power plant production, and create expensive cleaning costs. The reduction in power and increased operating costs caused from difficult scale conditions can directly impact a plants financial outcome.

Different types of geothermal fluids from different wells have brine with differing chemistry conditions are found in various areas around the world. Substantial differences can even be found within the various wells of a given field. The chemistry of these different brines varies and the differences will depend on several factors including the geology of the resource, temperature, pressure, and water source. Depending on the resource, steam and water ratios in the brine can vary significantly. The scaling and corrosion characteristics of brine and steam cause difficult problems in geothermal operation.

Scaling by mineral deposition is a common problem in almost all production wells, it occurs on all surfaces in contact with the brine produced; however, the most serious scale problems affect both reservoir permeability and well production. Several studies about down-hole scale characterization have been realized using X ray diffraction to identify the main minerals deposited inside the production lines.

The table below, presents typical minerals identified in scales inside the production wells and pipe network from various geothermal fields around the world.

Table 1. 1: Mineral composition of silica scales in geothermal systems

Mineral	Formula	Mineral	Formulae
Anhydrite	$CaSO_4$	Montmorillonite	$(Na,Ca)_{0.3,3}$ $(Al,Mg)_2$ Si_4O_{10} $(OH)_2.n$ H_2O
Anglesita	$PbSO_4$	Magnetite	Fe_3O_4
Calcite	$CaCO_3$	Pyrrhottite	FeS
Chalcopyrite	$CuFeS_2$	Quartz	SiO_2
Galena	PbS	Sphalerite	ZnS
Gypsum	CaSO4.2H2O	Silvite	KCl
Halite	NaCl	Talc	$Mg_3SiO_4O_{10}(OH)_{2.5}.n$ H_2O
Luzonite	Cu_3AsS_4	Verniculite	$(Mg, Ca)_{0.9}$ $(Mg,Fe)_3(Si,Al)_4$ O_{10} $(OH)_{2.5}$ H_2O
Magnesioferrite	$MgFe2O_4$		

The major species of scale in geothermal brine typically include calcium, silica and sulphide compounds. Calcium compounds frequently encountered are calcium carbonate and calcium silicate. Metal silicate and metal sulphide scales are often observed in higher temperature resources. Typical metals associated with silicate and sulphide scales include zinc, iron, lead, magnesium, antimony and cadmium. Silica can present even more difficulties, as it will form an amorphous silica scale that is not associated with other cations. All of these scales types can present challenging operating problems for geothermal plants.

Inside the wells, there are certain points where the internal diameter is considerably larger, making them the flush points. Most of the time, the scale precipitates there, but the flush points are not stationary due to other factors such as pressure in fluid reservoirs.

2.4.1 Types of geothermal scaling

Boiling point scaling in production wells

a. Occurs over limited interval in production wells
b. Caused by sudden pH changes due to boiling
c. Involves precipitation of calcium carbonates and metal sulphides
d. Problematic where fluids have high TDS or high concentration of dissolved calcium carbonate

Calcium carbonate scale frequently causes operational problems in the brine handling systems. It typically forms as a result of the evolution of CO_2 from the liquid phase. CO_2 evolves any time a pressure drop occurs. Pressure drops occur in the flash vessels and also in localized areas of production well pumps or elbows in surface piping. As CO_2 is evolved, the liquid phase will experience a corresponding pH increase. At elevated temperatures, even small amounts of calcium in the brine will precipitate with the pH increase. Fluids containing calcium (even small amounts) have the potential to form calcium scale, especially in the production wells. A high flow to the well –and also through the well pipe –will aggravate calcium scaling conditions.

Calcium carbonate scale can form in production wells, plant vessels and equipment, and injection lines and wells.

Metal sulphides; Sulphide scales can also be encountered in geothermal operation. Sulphide scales have been observed in high temperature as well as in low/medium temperature resources. Sulphide scales are associated with other metal cations forming scale compounds that are very hard and difficult to handle. Sulphide scale has been observed in production wells with two-phase flow and has caused plugging or choking of the brine flow from the well. Antimony has been observed in low/medium temperature resources and can form antimony sulphide deposits in binary plant heat exchangers. Because antimony is extremely insoluble, low levels of antimony (100 parts per billion) in a resource fluid can cause antimony sulphide deposit problems.

Calcium is an abundant mineral in rocks which have been altered by geothermal water, in particular where the water boils extensively in up-flow zones. Scales of calcite, and some times of aragonite, have been observed to form in some geothermal wells but not in others. The rate of scale formation varies enormously from place to place. In some cases, it can be dealt with, either by periodic mechanical cleaning of the wells, or by the use of chemical scale inhibitors. Calcite scaling in producing geothermal wells is generally only encountered as a problem if the first level of boiling is inside the well, as most often is the case. Theoretical considerations indicate that calcite super-saturation always results when extensive boiling of geothermal water is induced in discharging wells, irrespective of whether this boiling starts in the well or in the aquifer. The principal cause of this apparent discrepancy is considered to be the big difference in the volume of the well bore compared to the anticipated volume of connected pores in the aquifer, even at a small distance from the well. Calcite does furthermore not form significant deposits unless a certain degree of super-saturation is reached.

The calcium content of geothermal waters varies by several orders of magnitude, being highest for saline waters of relatively low temperature (>1000 PPM) and lowest for dilute waters of high temperature (<1PPM). The total carbonate content of geothermal reservoir water with temperature greater than about 200° C runs in the hundreds to tens of thousands of PPM.

2.4.2 Scaling mitigation methodologies in geothermal systems.

Different methods have been applied to cope with calcite scaling in production and injection wells. Methods involve periodic cleaning, either mechanical or chemical, or the use of inhibitors. The most successful mechanical cleaning method involves drilling out the scale with a small truck-mounted rig while the well is in production. By this method, the scale is brought to the surface, thus not cumulating at the well bottom. The well can be connected immediately after the cleaning operation is completed. This method of coping with calcite scales is feasible if the deposition is not very fast and cleaning is required no more than about twice a year. If scale formation is faster, the use of scale inhibitors is a more useful method. By this method, the inhibitor must be injected continuously into the well through tubing to a depth that is below the level of first boiling. Mechanical cleaning or the use of inhibitors is the most commonly applied remedies.

Chemical treatment of the geothermal water, either by an acid or CO_2, to make it calcite under-saturated has been tested. It has, however, several disadvantages. Due to the relatively high PH buffer capacity of geothermal waters, a large amount of acid may be required, making this treatment expensive and, therefore, not attractive economically. Further, acidification may render the water corrosive.

Solution 1

Periodic work-over of well Involving: reaming with a rig, high-pressure washing and acid cleaning.

Solution 2

Gradually decreasing wellhead pressure lowers the boiling point and thus the scaling point

Solution 3

Injection of chemical inhibitors in combatting geothermal scales.

Examples of inhibitors; polyacryllate Scaling inhibitors in surface equipment mostly for amorphous silica, Calcium carbonate and sulphides to a lesser degree

Silica related scale is one of the most difficult scales occurring in geothermal operation. Silica is found in virtually all geothermal brine and its concentration is directly proportional to the temperature of the brine. As brine flows through the well to the surface, the temperature of the brine decreases, silica solubility decreases correspondingly and the brine phase becomes over saturated. When pressure is dropped in the flash vessel, steam flashes and the temperature of the brine further decreases. In the flash vessel, the brine phase becomes more concentrated and the silica, already unstable, becomes even more unstable. Under these conditions, silica precipitates as either amorphous silica or it will react with available cations (e.g., Fe, Mg, Ca, and Zn) and form co-precipitated silica deposits. These deposits are extremely tenacious and can occur throughout the production field, plant and injection systems. Mostly they occur further away from wellheads, common after separator stations.

Quartz and amorphous silica are of interest in deposition studies. In liquid-dominated high temperature geothermal reservoirs, the amount of silica dissolved in the geothermal water depends on the solubility of quartz. However, amorphous silica is the form which precipitates from geothermal fluids upon concentration and cooling. Silica precipitation from geothermal fluids can occur over periods of minutes or hours after super-saturation occurs. Silica scales have been found throughout the fluid handling equipment of several geothermal facilities.

Siliceous scale is typically inert to most chemicals and, once deposited, is also somewhat resistant to mechanical removal. Hence, most treatment methods focus on prevention of silica deposition or on controlling the morphology of the silica deposited. Efforts to prevent scale deposition on surface equipment have included restricting steam separation - that is to say to operate the system at temperatures so high that amorphous silica super-saturation is not reached.

2.4.2.1 Silica concentrated scales in geothermal systems

a) Amorphous–silica (None crystalline type of silica).
b) Deep fluid saturated with respect to quartz
c) Boiling increases concentration of dissolved SiO_2 in injection pipelines particularly in wells after separator stations and surface equipment.
d) When the fluid reaches saturation with respect to quantities
e) Problematic Silica solubility and scaling curves.

When initially discharged, the silica content of water from wet-steam wells is governed by equilibrium with quartz in the producing aquifers, at least if temperatures in the reservoir exceed 180°C. The aqueous silica concentrations in the boiled water can be predicted quite accurately at any particular pressure from the quartz equilibrium concentration at the aquifer temperature. This is shown alongside aquifer waters at 250 and 300°C. Steam formation due to boiling, and therefore also the increase in aqueous silica concentration, is caused by flashing when the pressure is lowered. The resulting temperature and pressure changes due to such flashing are shown as solid straight lines. These changes can be calculated as the average fluid enthalpy is constant (adiabatic flashing).

Many treatment methods have been applied to reduce silica scaling in production wells and equipment. In order to avoid amorphous silica scaling in wells, it is common practice, whenever possible, to operate the wells at wellhead pressures higher than those corresponding to amorphous silica saturation.

1. Separating steam at high pressure –Wasteful, a lot of thermal energy wasted

2. Diluting separated water with condensate–Can cause corrosion

3. Acidification –Can cause corrosion

4. Crystallize silica in suspension [Crystallizer-Reactor-Clarifies process (pumping from conditioning ponds after it has cooled down and the silica has polymerized)] –Costly

When considering injection of cooled wastewater into either cold or hot ground water, the possible effects of mixing the two compounds of silica, Mg-silicate or Al-silicate deposition should be specifically looked at.

2.4.2.2 Detection and measurement of scales in production wells

In order to determine the location and thickness of scales in geothermal wells, different mechanical methods are used. These include:

1. Wire baskets of different diameters, lowered on a logging wire until it stops;

With different diameters of wire baskets the location and the thickness of scaling in the well can be determined by how deep the basket can be lowered into the well. These spot measurements can be done in the well under pressure.

2. Callipers logging tool, electrical logging tool with four fingers.

The disadvantage of the calliper tool is the temperature limitation of the electronics. Usually the well needs to be killed and cooled down for a calliper survey.

2.5 Fluids chemistry from geothermal wells

The chemistry of well discharges usually varies from one field to another. It also varies from one well to another, within the same field. After sampling and analysis of different wells fluids, mean values of well chemistry are taken to be representative of reservoir fluids. Deep reservoir fluid chemistry is influenced by boiling processes, fluid-rock interactions and mixing processes.

Chemical components in geothermal fluids are grouped into 2 distinct categories: mineral forming components; and conservative components. Mineral forming components: SiO_2, Na, K, Ca, Mg, S-H_2S and SO_4, C-CO_2, F, Al, Fe, Mn, etc. give information on deep reservoir temperatures, and boiling and mixing processes. Conservative components, e.g. Cl, B, and stable isotopes of deuterium and oxygen, are useful in determining reservoir recharge and re-injection (Wambugu, 1996).

Olkaria Northeast field wells discharge sodium-chloride water, with an average pH of about 6.7 to 7.4. The concentrations of sodium range from 450 to 850 PPM; chlorides range from 500 to 900 PPM (Appendix I); and water may be considered dilute with total dissolved solids (TDS) of about 2,500 PPM (Wambugu, 1996). The total carbonate concentration in the reservoir, calculated as CO2, ranges from 1,000 to 2,000 PPM in most well fluids.

After separation of reservoir water into brine and steam, most of the non-condensable gases (NCGs) escape into the gaseous phase (steam) while other gases remain in the liquid phase. Also, depending on separation efficiency, some chemicals with principal species being Na, K, Cl, Ca, Fe, etc. are mechanically carried over into the steam supply. Other chemicals with appreciable solubility in steam at the separator temperature (150°C) will partition into steam as molecular species and thus cannot be removed by mechanical separation. These consists of CO2, H2S, H2, N2, CH4, silica (SiO2), B, F, As, etc. The concentrations of chemicals in steam phase for Olkaria Northeast field were analysed and are given in Table 1.1 on mineral composition of silica on page 14.

The cyclone separators are vertical cylinders and are designed for high-efficiency steam separation (dryness fraction of 99.98%), so as to minimise the impurities in steam. Also, due to the relatively high percentage of non-condensable gases in the steam, the condensate formed has a pH of about 3.5.

2.6 Silica scaling in geothermal systems

Silica scales are found to some extent in all high temperature geothermal installations but by maintaining the temperature above the solubility level for amorphous silica (the non-crystalline form of silica), the scaling should not occur and thus this is one of the design criteria for most geothermal plants. In this way the high-pressure separator will not scale, nor the reinjection pipeline, assuming that the so called “hot-injection” method is used. In the high temperature reservoir before the fluid is extracted, the silica concentration is usually in equilibrium with quartz, the crystalline form of silica. Once the water starts to boil and cool down, the silica concentration in the water increases due to the steam loss. The water immediately becomes quartz supersaturated but quartz precipitates are not formed because of the slow growth of quartz crystals. Silica scales are first formed when the amorphous silica solubility curve is passed. Looking at these two curves it is clear that the “window of opportunity” for operating the geothermal plants free of silica scaling lies between the quartz and amorphous curves. This means in practice that only some 25% of the water can be converted by “flashing” into steam from liquid dominated reservoirs without the danger of silica scales, almost independently of the temperature of the resource (flashing= rapid conversion of water into steam). A silica “rule of thumb” may say that it is only possible to cool the water by some 100°C without the risk of scaling. Reservoir water of 240°C has thus to be separated above 140°C to avoid scaling. For this reason it is not of as great importance as one might think that the reservoir temperature be as high as possible, because the higher the reservoir temperature, the higher the temperature of re-injected water needs to be that puts a lid on the thermal efficiency.

In the combined heat and power geothermal plants the precipitation of amorphous silica can occur when the separated water flows through heat exchangers. In the heat exchangers the separated water is cooled down and becomes supersaturated with respect to amorphous silica. This commonly causes scaling in the tubes of the heat exchangers which have to be removed regularly. In the dilute high temperature fields where the chloride concentration is low the precipitation of amorphous silica can be postpone by slow flow rate through heat exchangers allowing the aqueous silica to form polymers in the solution. This has been applied at the Nesjavellir power plant reducing silica scaling in the heat exchangers. After heat exchangers the separated water flows through a large retention tank for further polymerisation of the silica before condensate is mixed with the separated water and re-injected into subsurface.

In low temperature geothermal systems the silica content is governed by the solubility of the silica mineral chalcedony at low temperature and quartz at higher temperature. In water from the low-temperature areas, although it is cooled in the district heating systems down to about 20°C, silica saturation does not occur.

Scaling is a common phenomenon in all geothermal installations in the world. It occurs due to interaction of geothermal water with rocks and boiling processes deep in the reservoir, resulting in supersaturated water due to the dissolution of minerals. Dissolution may be accelerated by temperature and, sometimes, it may be retrogressive depending on the solute (Gunnarsson et al., 2005). Calcite, silica and metal pyrite deposition are the most common scales sited in Olkaria Northeast field.

Calcite scaling is largely confined to wet wells and occurs when geothermal water becomes supersaturated with calcite due to a decrease in partial pressure of carbon dioxide leading to its precipitation. It occurs in both low- and high-temperature geothermal installations as polymorphs of calcium carbonate which include vaterite and aragonite (Opondo, 2002). Calcite deposition is highly controlled by water temperature and pH, according to the equation:

$$Ca^{2+}_{(aq)} + 2HCO^{-}_{3\,(aq)} = CaCO_{3(s)}\,(Calcite) + CO_{2\,(g)} + H_2O\,(l) \quad (1)$$

The solubility of silica in geothermal fluid is very dependent on temperature, the initial degree of super-saturation, salinity, pH, and the presence (or absence) of colloidal particles. Thus, separation temperatures of geothermal fluid need to be carefully chosen so that much of the silica will remain in solution or allow it to come out of solution before injection. Silica is mainly deposited as quartz or amorphous silica. Quartz (controls solubility of hot reservoir fluid) is deposited in the temperature range of 100-250°C and amorphous silica (controls solubility of low temperature fluid) in the range of 7-250°C (Gunnarsson, et al., 2005; Dipippo, 2005) depending on saturation, according to the equation:

$$OFeOH.\,H_2O + Si\,(OH)_4 = Fe\,(OH)_3.\,SiO_{2(s)} + 2H_2O \quad (2)$$

Metal sulphides, silicates and oxides are also common scaling problems in many low- and high-enthalpy geothermal installations. In low-enthalpy fluids containing high concentrations of dissolved solids, severe corrosion of mild steel production well casings occur. The iron oxides formed from this corrosion react rapidly with sulphide-rich geothermal fluids causing metal sulphide deposition, mainly found in high-temperature environments. Iron sulphides identified in production and re-injection wells are pyrite, mackinawite, pyrrhotite and small amounts of iron and calcium carbonates (Lichti and Braithwaite, 1980).

In high-enthalpy systems, metal sulphides and oxides are also deposited in surface equipment e.g. separators, silencers, and weir boxes, etc. due to cooling and pH change accompanying flashing processes leading to the concentration of metal ions.

2.7 Corrosion in Geothermal systems

Corrosion is an enormous challenge in both low- and high-temperature geothermal installations. It is most prevalent in wellhead equipment, transmission pipelines and geothermal fluid utilization facilities. Also, re-injection wells, power plant substations, and electronic devices used to control utilization processes, etc. are attacked by corrosion leading to their degradation and inefficiency.

The most common forms of corrosion encountered in both low- and high-temperature geothermal installations are general corrosion, pitting corrosion, crevice corrosion, turbulence corrosion, galvanic corrosion, selective attack and stress corrosion cracking. All these forms of corrosion are accelerated by the presence of oxygen, high pH, high temperature, and the presence of water or moist air, characteristic of geothermal fluid (Gunnarsson et al., 2005). Corrosion is well explained by the anode/cathode reactions below. Since most installations are made of mild steel and iron alloys, the anodic/cathodic reactions are given with iron attack in mind.

Cathode reaction:

$$4e^- + O_2 + 2H_2O = 4OH^-_{(aq)} \qquad (3)$$

Anode reaction for iron:

$$2Fe = Fe^{2+} (aq) + 4e^- \qquad (4)$$

Combining these two reactions to form a total reaction:

$$2Fe + O_2 + 2H_2O = 2Fe(OH)_{2(s)} \qquad (5a)$$

$$2Fe(OH)_2 + \frac{1}{2} O_2 + H_2O = 2Fe(OH)_{3(s)\ (rust)} \qquad (5b)$$

Various methods are employed to prevent corrosion attacks: good material selection; minimising oxygen ingress by painting; the use of fibre glass and stainless steel material; lagging; pH control; and good design among others.

2.8 Typical Geothermal energy generation equipment

2.8.1 Steam turbine

The steam turbine is the most important equipment in a geothermal power plant, though it depends on size, construction and the power cycle. Steam can be admitted into a turbine as: direct dry single-pressure steam; separated single -pressure steam; single-flash single-pressure steam; double-flash 2-pressure steam; or multi-flash (3 or more pressures). Other possible power cycles are brine/hydrocarbon binary cycle; or as hybrid fossil systems, among others.

After steam is expanded through a turbine, it is exhausted into the atmosphere (back pressure turbine) or condensed into a condenser (condensing exhaust turbine). In binary plants, geothermal fluid heats a secondary fluid in a heat exchanger, and the secondary fluid is expanded through a turbine (Organic Rankine Cycle). In hybrid systems, geothermal fluid is used to preheat a working fluid, then flue gases from coal or fossil oil superheats the working fluid.

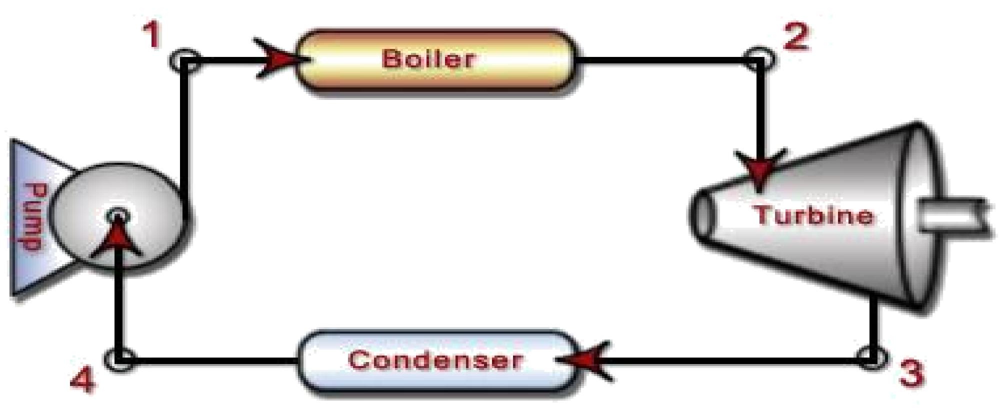


Figure 2. 6: The Rankin cycle (Organic) diagram

For separated single-flash steam, Figure 2 (T-S diagram) shows geothermal fluid from a production well at 1, passing into a cyclone separator at 2, where it is separated into liquid (brine), 3, and a steam phase at 4. Steam expands through the turbine and is exhausted into the condenser. The energy of inlet steam (inlet enthalpy), h_2, is reduced to thermal and pressure energy (exit enthalpy), h_{3s}, at exhaust conditions. Under isentropic expansion (constant entropy), point 2 to 3s, the work extracted from a steam flow rate of 1 kg/s is given as:

$$W = h_2 - h_3s \tag{1}$$

Where W = Work output from turbine (kJ/kg);

h_2 = Steam inlet enthalpy (kJ/kg);

h_3s = Steam exit enthalpy (kJ/kg).

However, isentropic expansion is an ideal process and the factor, isentropic efficiency, η, is introduced to compare the actual turbine expansion to the isentropic expansion process, given by the formula below:

$$\eta = \frac{Actual\ Expansion}{Isentropic\ Expansi} = \frac{h_2 - h_3}{h_2 - h_{3s}} \tag{2}$$

where h_{3s} = Actual steam exit enthalpy after expansion (kJ/kg).
For steam flow rate, m (kg/s), actual work extracted from the turbine, is given by:

$$\mathbf{P = (h_2 - h_3)} \tag{3}$$

where P_{actual} = Turbine power output (kW).

To extract maximum energy from the turbine, steam is expanded until it is at as low a pressure as possible. However, the limiting conditions are the exhaust dryness fraction ($\boldsymbol{X} > \mathbf{86\%}$), and the cooling water temperature which depends on ambient conditions.

Another factor which is important in a power plant is the utilization efficiency, η_u, which compares the turbine output with the maximum theoretical obtainable output when steam is exhausted to sink conditions and is given by:

$$\eta_u = \frac{Power\ output}{Exergy} \tag{4}$$

In power generation practice, some terms used are defined below:

Availability factor; is the ratio of the time the turbine is running to the total available time;

Load factor; is the ratio of the units of power generated to the power that the turbine could have generated, if it was running at the rated output for the total available time;

***Utilization fact**or* is the ratio of units of power generated to the power that the turbine could have generated, if it was running at the rated output for the actual time run;

Frequency of breakdowns is the number of times the turbine trips in a specific time e.g. a month.

Olkaria II steam turbine is a 6-stage impulse reaction turbine and geothermal steam passes through the steam chest at a pressure of 4.8 bar-a and steam chest nozzles to the turbine first stage rotating blades. Steam then alternates through the stationary blades (diaphragms) and rotating blades (turbine rotor) and is exhausted to the main condenser after the 6rotating row of blades at a pressure of 0.075 bar a.

The 3 turbo-generators are identical and the turbine has the following specifications:
Type of steam turbine – SCIF -30’’ - Single Cylinder, single flow, down exhaust type, Impulse Reaction Condensing turbine
Rated Output at Generator terminals (a) – 34,830 KW
Rated Output at Generator terminals (b) – 35, 440 KW
Rated speed of turbine - 3,000 rpm
Rotating direction (view from GOV. Side to GEN. Side) – Clockwise
Rated steam pressure at main steam strainer – 4.8 bar a
Rated steam temperature at main steam strainer – 150.3 deg. C
Turbine exhaust pressure at 100% load – 0.075 bar a
Turbine exhaust pressure at 90% load – 0.064 bar a
Number of stages – 6
Last stage dimension – 762.0 mm (30 inch)
Outside Diameter – 3,000.0 mm

2.8.2 Condenser

A condenser is a type of equipment that receives exhaust steam from the last turbine stage (6^{th}) blades and allows condensation processes to take place. This is done by spraying a jet of water onto the steam to condense it. With the help of two Hot well pumps (rating 3.3 KV each), the condensate water is pumped out of the main condenser for cooling at the cooling tower.

The main condenser is a direct contact spray type where exhaust steam is sprayed with cold water (condensate) from the cooling tower. Cold water at a temperature of 21 ^{o} C from the cooling tower enters the condenser through a 1050 mm diameter pipeline and is sprayed to the turbine exhaust steam through nozzles. Exhaust steam at 47^{o} C, mixes with cold water to form condensate at 42^{o} C which passes to the cooling tower for heat rejection.
In geothermal power plants, condensers are used to condense turbine exhaust steam, hence creating sub-atmospheric conditions in the condenser. Back pressure turbines do not use condensers, instead exhausting the steam directly to the atmosphere.

Condensers are mainly divided into two types: surface condensers and direct-contact condensers (spray, barometric and jet types). In surface condensers, turbine exhaust steam passes through the outer surface of a bank of tubes carrying cold water, hence condensing steam on the shell side. In direct-contact condensers, exhaust steam is directly sprayed with cold water (mixing two streams), with the subsequent steam and gas cooling and condensation. In barometric condensers, cooling water is made to cascade down through a series of baffles and thoroughly mixes with turbine exhaust that is rising from a lower inlet. In jet condensers, exhaust steam and cooling water are made to cascade down to a diffuser, (El-Wakil, 1984).

Condensers are designed to provide low turbine exhaust pressures for maximum turbine efficiency and work extraction, and to ensure minimum cooling water for complete steam condensation and the reduction of dissolved geothermal gases. In order to meet these requirements, some features are included in the condensers design:

1. Minimum pressure drop for both steam/gas and cooling water distribution system;
2. Maximum removal of non-condensable gases;

3. High heat transfer coefficients for maximum steam condensation and gas cooling;
4. Prevention of ambient air leakages; and
5. Compactness and low water level arrangement.

The design of a direct-contact condenser is determined by the total volume required for maximum heat and mass transfer. The heat transfer is calculated by the empirical formulae:

$$V = \frac{Q}{Uadt} \tag{1}$$

where V = Volume of condenser (m^3);
Q = Condenser heat load (W);
U = Overall heat transfer coefficient (W/m^2 K);
a = Internal area (volumetric term for indeterminate transfer area of drops) (m^2/m^3);
dt = Logarithmic mean temperature difference (K).

However, manufacturers generally use the heat transfer methods with modifications of these empirical relationships.

The condensation process occurs when the latent heat of the inlet steam at point 1 (Figure 3) is absorbed as sensible heat in the cooling water at point 2. When the temperature of the water is high enough to reverse the gas absorption, the stripping process is said to occur. This occurs when the turbine exit steam has high water vapour content such that the partial pressure of gas is lower than the equilibrium partial pressure and the gas tends to be stripped from the liquid (Hart, 1979). The mass and energy balance, with m and h denoting mass-flow rates and specific enthalpies, respectively, give:

The condenser has to operate in the stripping regime, such that 95% of the steam is condensed in the main condenser, and provide a gas cooler to operate in the absorption regime to complete condensation and gas cooling. The two streams, one with a large flow of condensate from the main condenser with a low concentration of dissolved gases, and a smaller one from the gas cooler containing highly dissolved gases, are mixed to form one stream at 3, with acceptably low gas content.

2.8.3 Cooling tower

Turbine exhaust steam carries a lot of heat which requires dissipation. The heat rejection process can be done using several different methods dependent on the cooling medium: cooling ponds/lakes; spray ponds/canals; ‘once-through’ cooling; or the use of cooling towers (wet mechanical draft, wet natural draft, dry/wet cooling towers) among others.

Most cooling towers use evaporative cooling, where about 1-3% of re-circulating water evaporates to cool the remainder of the stream by 8-12°C (evaporative cooling), depending on the ambient wet and dry-bulb temperature. Water to be cooled is brought into intimate contact with a moving air stream. About 75% of the cooling takes place by evaporation and the remainder by conduction to raise the dry bulb temperature of the air. The air stream leaves the top of the tower, when it is at near-saturation condition, as a plume.

The cooling tower receives hot condensate at a temperature of 42° C and cools it to 21° C. The cooling effect takes place as condensate flows downward through the honey comb corrugated plastic fills and the air flows upwards due to air draught from the fans. The counter flow of the 2 streams (air and condensate) causes cooling of the condensate by evaporation.

The cold condensate collects at the bottom of the cooling tower basin and flows back to the main condenser through the glass reinforced pipes (GRP), to be sprayed to turbine exhaust steam.

To assess the fouling mechanisms, observed fouling patterns must be analysed. Findings from both the literature and from observations recorded are discussed. Vigueras Zuniga (2007) reports deposits on the gas turbine compressor rotor and vanes, with deposits both on suction and pressure surface. There is evidence of increased deposits in the leading edge region of the rotor blade suction side. The deposits exist on both the suction and pressure side of the rotor blades, with fewer deposits near the leading edge and in the hub region. The deposits seem to indicate the location of the transition area of the boundary layer.

To enhance heat exchange between water and air, the area of contact between the water and air stream is increased by spraying water in thin jets into packing fills to form thin water film.

The Energy and mass balance in a wet cooling tower is calculated as follows;
For a better understanding of a wet cooling tower, some terms needs to be defined:

Relative humidity, φ, is the ratio of partial pressure of water vapour, P_v, in air to the partial pressure of water vapour that would saturate the air at its temperature, P_{sat}:

$$\phi = \frac{P_v}{} \tag{1}$$

P_{sat}

Humidity ratio, ώ, is the mass of water vapour per unit mass of dry air:

$$\omega = \frac{m_v}{m_a} = \frac{0.622 P_v}{P - P_v} \qquad (2)$$

where P = Atmospheric pressure.

Wet-bulb temperature, T_{wb} is the temperature of air when it is fully saturated with water vapour;

Dry-bulb temperature, T_{db} is the temperature of air as commonly measured i.e. when not fully saturated with water vapour;

Approach is the difference in temperature between the cold water entering the cooling tower and the wet-bulb temperature of the outside air;

Range is the temperature difference between cold water exiting tower, and hot water entering the cooling tower.

2.8.4 Pumps

2.8.4.0 Introduction

In order to make water and other liquids move in pipes and channels, mechanical energy is usually imparted by pumps. Pumps operate like fans, though fans normally deal with air and gases. They are mostly driven by being coupled directly to the motor driving shaft or through some speed reduction devices like gear wheels.

2.8.4.1 Classification of pumps

Pump types can be grouped into two main categories: centrifugal (dynamic) and positive displacement pumps. Centrifugal pumps impart kinetic energy to a liquid by the spinning motion of an impeller, while positive displacement pumps operate by trapping liquid into pump cavities and displacing it to pump discharge.

Centrifugal pumps are further divided into radial flow and axial flow pumps. Radial pumps move the liquid outwards from the centre of the impeller into the scrolled casing, where some kinetic energy is converted to pressure forcing the liquid out of discharge. Axial flow pumps impart energy through the lifting action of propeller-shaped vanes resulting in axial discharge.

Positive displacement pumps are divided into rotary and reciprocating types. They provide a constant volumetric flow rate at a particular speed independent of pressure and liquid characteristics, and thus are mostly used for chemical dosing.

2.8.4.2 Pump operating characteristics

The performance of a pump is defined by the flow rate and the total dynamic head across it. When a pump pushes water or liquid through a piping system, there is resistance to the flow from friction and inertia pressure. This resistance depends on type, size and length of pipe as well as type and number of pipe fittings.

The power consumption for a pump depends on total head and liquid flow rate. The total head, Pt, depends on the height that the liquid is raised.

The performance of a centrifugal pump is defined by impeller diameter, pump speed, flow rate, head, power and fluid characteristics.

5. Pump performance with a specificimpeller size is shown as a continuous curve between no-flow conditions.

2.8.5 Air Compressors

Compressed air systems are widely used in power plants to provide compressed air for system control and domestic uses. The systems consist of three main components: compressor plant (compressor, storage tanks, dryers and coolers); distribution piping network; and equipment service lines. Air compressors are grouped into positive displacements (using pistons and rotors) and dynamic displacements (using impellers or blades). They draw in air and discharge it at higher pressures, usually in storage tanks or piping systems for use in the plant.

The changes in pressure, temperature and volume of a given air mass conform to the ideal gas laws as follows:

$$\frac{P_1V_1}{T_1} = \frac{P_2V_2}{T_2} \qquad (1)$$

where P_1, P_2 = Initial and final absolute pressures (Pa);
V_1, V_2 = Initial and final volumes (m^3);
T_1, T_2 = Initial and final temperatures (K).

The ideal gas laws can be written in terms of volumetric flow rates as:

$$\frac{P_1Q_1}{T_1} = \frac{P_2Q_2}{T_2} \qquad (2)$$

Where Q1, Q_2 = Initial and final air flow rates (m^3/s).
However, during the actual compression processes, the ideal gas laws are not followed because the processes are non-adiabatic (heat addition or removal to the system occurs) and non-isothermal (temperature changes during the process).

2.8.6 Liquid ring vacuum pump (LRVP), ejectors and inter-condensers system.

Non-condensable gas extraction systems are installed in power plants to remove gases from turbine exhaust steam, hence maintaining condenser pressure. Before gas removal, it is appreciably cooled, so as to dissolve some in water and also reduce its volume. This reduces the size/capacity of the gas extraction systems and hence their capital costs.

Steam ejectors of the nozzle types and the liquid ring vacuum pumps (LRVP) are the most common types of equipment used in gas extraction systems, though their selection depends on the gas content in steam. Selection of a particular system also depends on reliability, initial cost, operating costs and space requirements, and the frequency and complexity of maintenance. Steam ejectors operate by Bernoulli's principle, which relates kinetic energy and potential energy in a flow stream. The relationship is given by:

$$\frac{P}{\rho g} + \frac{v^2}{2g} + z = K \qquad (3)$$

where P = Pressure in the stream (Pa);
ρ = Average density of the gases (kg/m^3);
v = Velocity of the gases (m/s);
g = Gravitational acceleration (m/s^2);
z = Elevation (m);
K = Constant.

2.8.7 Scrubber

In the power plant, a scrubber is one such important auxiliary equipment that a flash type power plant cannot run without. A scrubber has got two important functions in a power plant.

i. Drying the Steam to the turbine up to 99% steam dryness.
ii. Scrubbing or cleaning the steam before entry into the turbine.

In the flash type power plants, special cyclone type steam scrubbers are used for these functions. These types are of very high performance and reliability and they placed just preceding the steam turbines. A scrubber works under the principle of a centrifuge system. Wet and dirty Steam enters the scrubber vessel from one side at a velocity of 40 m/s and leaves from the other side after decanting and filtration process cleaned and ready to enter the turbine.

The scrubber cleans the steam because the steam-impurities mixture has a higher density than pure saturated steam. The difference in densities forces the impurity to settle at the bottom of the outer chamber of the vessel while the scrubber cleaner steam leaves from the inner chamber.

It is thus important to keep the scrubber all the time containing some water to aid the vessel in the scrubbing action during operation. The minimum required scrubber level is 300 mm and a maximum of 2400 mm. A scrubber level of 2400 mm trips the turbine. This is because an interlock has been put in place not to exceed this level as this has a serious risk of admitting water into the steam turbine.

At no time should the scrubber vessel operate without water. This level should not go below 300 mm for effective scrubbing of steam before entry into the turbine. The figure below shows a diagram of the Scrubber vessel of the vertical type being used in Olkaria II power plant.

2.8.8 Plant fouling

Parker and Lee (1972) studied fouling patterns on rotating blades for very fine (0.13 to 0.19 lm) particles. Sample results of the estimated deposition rates for different regions of the blade surface were reviewed. These results show high deposition rates at the blade leading edge, relatively low deposition on the pressure side, and a higher deposition rate on the suction side toward the trailing edge. The deposition rates on the suction surface near the trailing edge are where the boundary layer is thick and turbulent.

On the other hand, Syverud, et al. (2007) detected in a gas turbine subjected to salt water spray deposits mainly on the blade pressure side and the blade leading edges, causing a significant increase in surface roughness. They also found, like other researchers, that the majority of the deposits occurred on the early stages of the compressor. It must be noted that the salt water spray in these experiments formed larger size and wet droplets. Obviously, the relative humidity (and with it the salt particle size) drops in the latter compressor stages due to the temperature increase. Typical particle sizes after air filters in industrial gas turbines will be much lower. As a result of the acceleration of the inlet air when it enters the compressor through a bell mouth and inlet guide vanes, the relative humidity of the air will increase. An ambient relative humidity of 50 percent can, therefore, lead to condensation at the inlet guide vanes. The droplets that can form due to this effect may scrub entrained solids, such as salts, as well as some gases like CO2 or SOx. Because they form downstream of the filter, their droplet size can be larger than the particle sizes normally prevented from passing through the air filter. They also will create an acid atmosphere within the compressor; thus, causing corrosion pitting on the blades (corrosion pitting can be prevented by appropriate coatings).

Another area that is affected by fouling is the compressor shroud or casing. Elrod and Bettner (1983) compared the performance of the axial compressor of a gas turbine for different shroud roughness levels. Comparing the results for design roughness (1.8 lm) with a rough (13 lm) shroud, the compressor loses about 1 percent in flow capacity and about 1 percent in peak efficiency. The added wall roughness increases the wall boundary layer displacement thickness.

The type of foulants entering the compressor varies widely from site to site. Deposits of oil and grease are commonly found in industrial locations as a result of local emissions from refineries and petrochemical plants, or from internal lube oil leaks (Meher-Homji, et al., 2009). These types of deposits act as "glue" and entrap other materials entering the compressor. Lube oil ingested into the flow path is spread by centrifugal and aerodynamic forces and generates a film on ten blades that allows even larger particles to stick to the surface.

Coastal locations usually involve the ingestion of sea salt, desert regions attract dry sand and dust particles, and a variety of fertilizer chemicals may be ingested in agricultural areas.

The fouling deposit mechanisms were discussed in detail by Kurz and Brun (2012) and are, thus, not further discussed herein. Similarly, the impact of fouling on gas turbine performance has been discussed in many papers and a good summary can be found in Kurz and Brun (2009).

Figure 2. 7: Cooling tower

Figure 2. 8: Eroded turbine diaphragms

Figure 2. 9: The turbine-generator assembly at Olkaria II power plant

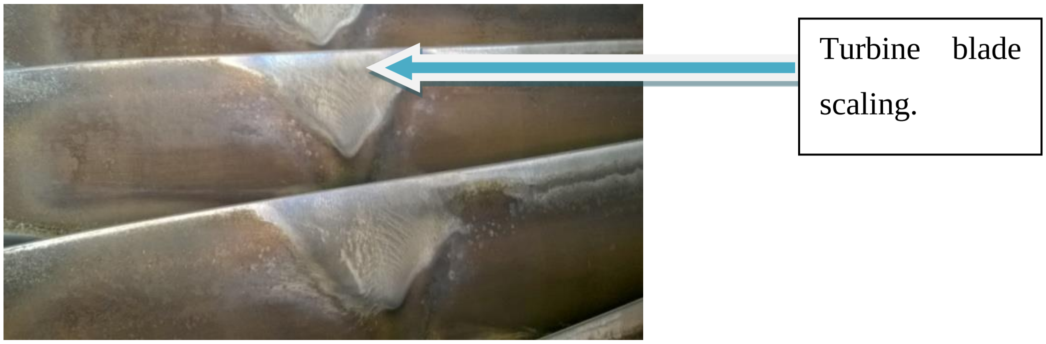


Figure 2. 10: Turbine blade scaling

2.8.9 Challenges in a geothermal power plant

There are so many operational activities which are carried out on a daily, weekly and monthly basis in every power plant. These routine activities must be conducted in accordance to the set out procedures in the operational manuals. An able team of the operational crew must all the time remember not only to carry them out but also conducting them as per the standard of practice.

Among the many routine activities in a power plant includes;

a. Oil inspections
b. Bearing Temperatures
c. Load generation and monitoring
d. Strainers cleaning
e. Circulating water flows
f. Hot well temperature.

CHAPTER THREE
RESEARCH METHODOLOGY

This chapter discusses the research method, research design and the experimental set up in trying to achieve the intended research objectives earlier proposed in chapter 1. It also describes in a step wise manner the procedure to be followed in order to achieve and improve the steam turbine efficiency by clearing silica scale formation and deposition in Olkaria II geothermal power plant.

The methodology for conducting the experiment is also demonstrated for ease of understanding as well. The data for the research are also recorded with the main purpose of its analysis in the succeeding chapter. The data recorded was carried out when the plant was in generation before steam washing was done and after. The interpretation of the data recorded during the study by the researcher is carried out with very minimal interference to power generation hence avoiding the company's production process. The researcher undertook the experimental tests with help of other engineers and technicians at the power plant during the process in order to improve on the accuracy and reliability of the results to be obtained. The researcher thereafter analysed the data recorded with the help of a computer program where he used Microsoft office word, excel and Statistical package for social sciences (SPSS) to come up with the graphical representation and analysis of results. The data was analysed, interpreted and discussed in chapter four clearly as they were done at Olkaria II geothermal power plant.

3.1 Research design

The study design used by the researcher was an experimental test based on a case study of Olkaria II Power plant. Olkaria II geothermal power plant is a geothermal power plant comprising of three units with each unit generating a power output of thirty five megawatts (35 MW).Over time because of silica scaling on the first stage of the turbine blades, the power generated deteriorates and excess steam is required to generate the rated capacity of the turbine. The research design is based on an already generating power plant with an experimental set up for quantitative analysis of the gathered information of the steam and blade washing method for the plant. The research design also encompasses the statistical analysis methods integrating with the Microsoft office and excel.

3.2 Steam washing

Steam washing is a basic steam scrubbing technique of introducing water or condensed steam (condensate) into the steam flowing along the steam pipeline at a convenient location such that it may not contribute to a considerable drop in steam temperature and enthalpy. The most appropriate location for the introduction of the condensate would be about fifty metres on the steam pipeline upstream of the turbine inlet. This is upstream of the separator vessel (scrubber) so that any excess condensate injected into the steam pipeline might be drained through the scrubber drains to the nearby cooling tower. This collects unwanted substances such as all forms of scales including silica scales, debris, sludge and rock formations contained and moving along with the steam into the wash water. The rock formations, debris and all manner of scales are dropped in the scrubber vessel by virtue of their densities and the less dense steam is forced under pressure to flow along the main steam pipeline. Silica, boron, ammonia and arsenic are all trapped inside the scrubber vessel and are removed readily in this manner. However other non-condensable gases such as carbon dioxide, Nitrous oxide and hydrogen sulphide cannot be removed readily by scrubbing as they quickly proceed with the steam into the turbine. In order to optimize condensate water injection rates used for steam scrubbing, an on-site analytical test procedure must be developed, based on the turbine scale composition.

The researcher started one steam wash pump after fully opening the manual isolation valve on the local pump panel. This was done while monitoring the steam wash condensate flowing into the main steam pipeline at a constant rate.

The steam washing condensate flow was adjusted to position in order to modulate and provide a condensate flow rate of between (4.0-6.0 tonnes/hour) at a pressure of about 15 barg.

The main steam flow rate flows at 260 tonnes/hour at a steam pressure of 4.2 bar g.

The properties of steam flowing to the power plant from the reservoir varies from one well to the other and each steam source has a unique steam quality and purity.

The Turbine supervisory instruments were then monitored for the turbine and the wash system and the following parameters were then recorded;

a) Main steam pressure.
b) main steam temperature,
c) Main steam flow rate.

d) Condenser vacuum.

e) Governor percentage opening.

f) Power output-Load.

g) Steam chest pressure (bar g).

h) Turbine system vibration

i) Rotor position.

j) Bearing metal temperatures for all the four bearings.

k) Steam Wash condensate flow.

l) Steam wash pump discharge pressure.

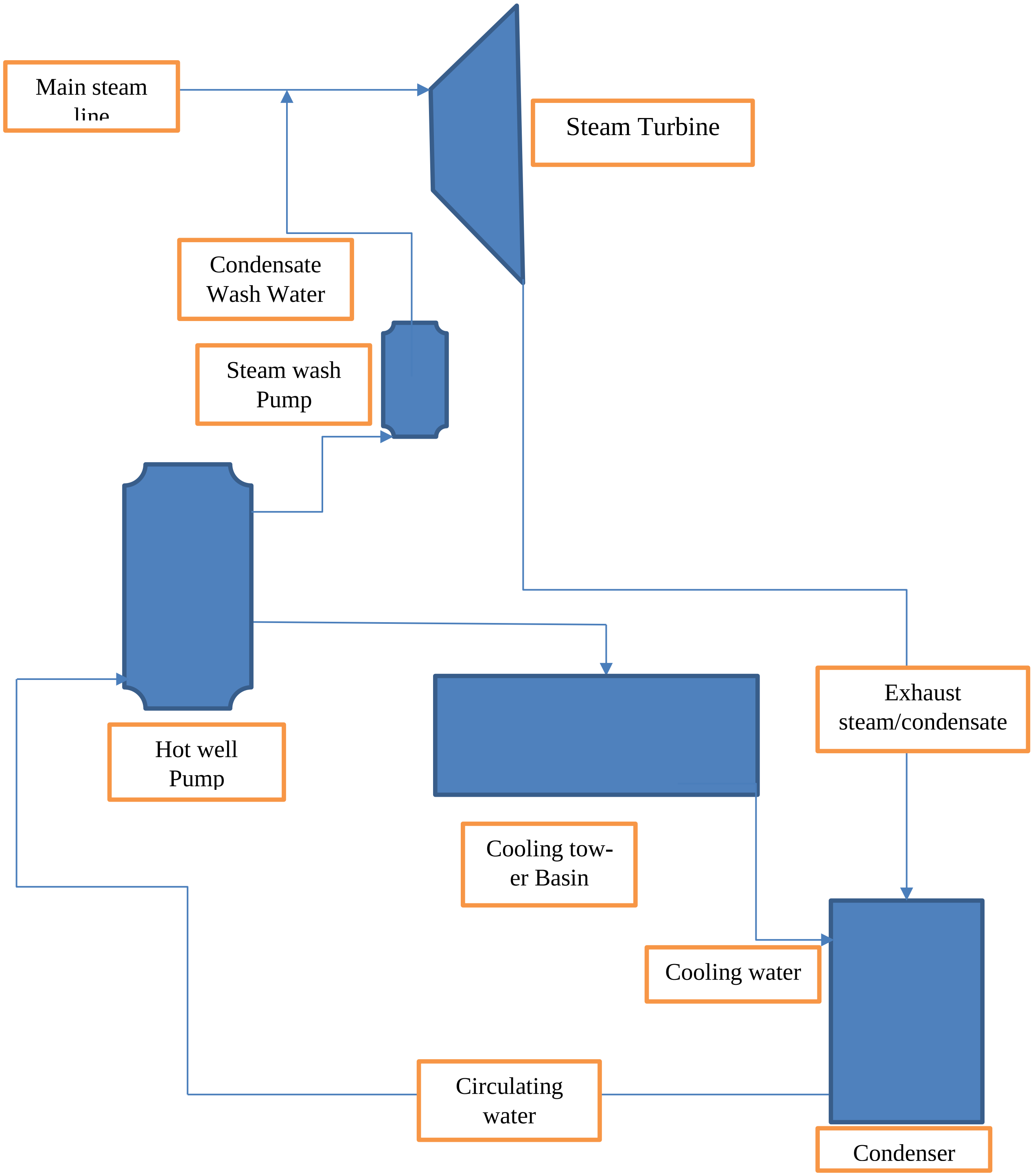
m) Steam scrubber level.

3.2.1 Preparation for steam washing:

1. The condensate water flow control valve and manual isolation valve were fully closed before the wash pump was started.
2. The two hot well pumps were put into service in the normal start up procedure.
3. After establishing water circulation system and the steam system the unit was synchronised to the grid to export the electrical energy (power output).
4. Take up the generator load to full load and ensure that this load is stable and ready to start steam washing.
5. The manual isolation valves and the discharge nozzle valves were closed fully.
6. The turbine supervisory instruments and the steam wash system were Measured and recorded for the following parameters before the steam washing operation;

    a) Main steam pressure (bar g)
    b) Main steam temperature (^{0}C)
    c) Main steam flow i.e. more than 260 tonnes/hour.
    d) Condenser vacuum (bar g)
    e) Governor valve opening (%)
    f) Power output- Load (MW)
    g) Steam chest pressure (bar g)
    h) Vibration readings in (mm/sec)
    i) Rotor position (mm)
    j) Bearing metal temperature (^{0}C)
    k) Steam wash condensate water flow rate.
    l) Steam wash pump discharge pressure (bar g)
    m) Steam scrubber level (mm)

Figure 3. 1: Schematic drawing for the Experimental set up for steam Washing Operation in Olkaria II Power plant



3.2.2 Steam washing operation;

1) The steam wash pumps were started from the local panel and the pump discharge monitored until constant flow rate is achieved.
2) The manual isolation valves and the discharge nozzle valves were fully opened.

Figure 3. 1: Steam washing valve arrangements

<u>Adjusting the Steam Washing Flow rate</u>

I. Flow adjustment:

The position of steam scrubber wash water control valve was adjusted to provide a condensate flow rate of (4.0-6.0 t/hr.) proportionate to the main steam flow rate of between (130-260 t/hr).

II. Operation period:

The properties of Geothermal steam and percentage of impurities vary from one well to another as well as the reservoir, and the nature and accumulation rate of scales vary in the same manner.

3) The turbine supervisory instruments and the steam wash system parameters were both measured and recorded as follows during the operation;
   a) Main steam pressure
   b) Main steam temperature
   c) Main steam flow
   d) Condenser vacuum
   e) GV Opening
   f) Load output
   g) Steam chest pressure
   h) Vibration
   i) Rotor position
   j) Bearing metal temperature
   k) Wash water flow
   l) Wash pump discharge pressure

m) Steam scrubber level

Figure 3. 2: Steam washing valve closed before the experiment

Figure 3. 3: Steam washing flow meter (4-6 tons/hr)

3.3 Turbine blade washing

Turbine blade washing is a procedure used to clean steam turbine blade of solid deposition by intermittently injecting warm condensate water into the main steam line. The cleaning process is carried out with the turbine operating at partial load. This technique has been successfully used in geothermal steam turbines for a number of years. It is generally not recommended for frequent use, due to the inherent danger of water droplet erosion and thermal shock effects. Turbine wet-steam washing must, for the above reasons, always be carried out with great care and under carefully controlled conditions. . The characteristics are measured at the commissioning stage. It is possible to recognize the scaling at first stage nozzle in comparison with this characteristic at the commissioning stage. If steam chamber pressure increases up to about 15% from the initial operating pressure, turbine blade washing should be carried out.

The condensate washing action functions principally in two ways

1. It dissolves soluble solids contained in the deposited scale and so weakens the scale's matrix.

2. The weakened scale matrix, consisting largely of silica and its compounds, is then mechanically washed away by droplet impingement action and liquid flow.

It is generally recommended that steam entering the inlet nozzles of the turbine during washing has a dryness ranging between 90% and 95% (by weight) and that all casing and labyrinth seal drains be kept open. To minimize thermal shock and improve the homogeneity of the wet steam entering the turbine, it is advised that the temperature of the condensate injected into the steam flow be at least 100° .The wet steam washing should be started gently, and the steam wetness controlled. The liquid injection quantity should be monitored and can be gradually increased until the values obtained indicate that the inlet steam is within the above wetness range.

It is recommended that the progress of the washing be initially gauged by chemical analysis of the condensate from the turbine casing drains. When concentrations measured in the condensate have reached normal values, the washing can stop. A recovery of any lost generating capacity also indicates adequate cleaning. It is further recommended that the cleaning be carried out at an approximately constant load, somewhere in the mid-load range. This improves the ability to accurately control the wetness of the inlet steam and reduces possible erosion effects while keeping steam velocities through the passages at a reasonable level for efficient scale removal.

Before blade washing, the researcher confirmed that the Turbine wash shut off valve and flow adjusting manual valve are fully closed, hot well pumps were placed into service for circulating water and confirmed that minimum flow line was in service. The researcher further opened the air vent valve for air bleeding and after confirming that the line was filled with water and closed the valve and confirmed that the unit load was greater than 80% of rated load (≥ 27.8 MW). The researcher later monitored the instruments around turbine and the wash system.

The study measured and recorded Main steam pressure, main steam temperature, main steam flow, condenser vacuum, governor valve opening (%), generator load, steam chest pressure, vibration, rotor position, differential expansion, bearing metal temperature, thrust Bearing metal temperature, wash water flow, wash pump discharge pressure, blade wash pump is energized and ready for start-up.

3.3.1 Preparation for Blade washing;

i. The condensate water flow control valve and manual isolation valve were fully closed before the wash pump was started.
ii. The two hot well pumps were put into service in the normal start up procedure.
iii. After establishing water circulation system and the steam system the unit was synchronised to the grid to export the electrical energy (power output).
iv. Take up the generator load to be greater than 80% of rated load ($\geq$ 27.8 MW) and that this load is stable and ready to start blade washing.
v. The manual isolation valves and the discharge nozzle valves were closed fully.
vi. The turbine supervisory instruments and the steam wash system were Measured and recorded for the following parameters before the blade washing operation;
    a) Main steam pressure
    b) Main steam temperature
    c) Main steam flow
    d) Condenser vacuum
    e) Governor valve opening (%)
    f) Generator load
    g) Steam chest pressure
    h) Vibration
    i) Rotor position
    j) Differential expansion
    k) Bearing metal temperature
    l) Thrust Bearing metal temperature
    m) Wash water flow
    n) Wash pump discharge pressure
    o) Blade wash pump is energized and ready for start-up.
    p) U seal pumps available and running.

3.3.2 Blade washing steps

1. The blade pumps were started at the local panel.

2. The discharged atomised water into the main steam line is drained into the scrubber draining to the cooling tower basin.
3. The shut off valves were fully opened and the blade wash pumps started.
4. The flow adjusting manual valve was gradually opened at the pump local panel, monitoring the wash water flow.

During the initial turbine blade washing operation, the condensate water was injected at a quantity of about 2.5 ton/hr, and gradually increased according to the effectiveness up to a maximum of 6 ton/hr. The properties of geothermal steam and percentage of impurities vary from one well to another and so is the nature and accumulation rates of scales. Therefore a suitable pump operation period and injection flow rate was established through the actual operation to achieve the safe, effective and successful results.

The Figure 3.4: below shows the spray nozzles positioning on the main steam pipeline for steam washing operation. The spray nozzles spray atomised water into the main steam pipeline for the precipitation of the minerals and silica scales. The atomised water travelling at the velocity of the main steam, erodes the silica scales stuck on the 1st Stage blade nozzles of the turbine.

Figure 3. 4: Steam washing Spray nozzles

3.4 Recording of data from Supervisory instruments

The instruments readings around the turbine and the steam wash system were measured and the following parameters recorded during the operation;

a) Main steam pressure
b) Main steam temperature

c) Main steam flow
d) Condenser vacuum
e) Governor opening
f) Load output
g) Steam chest pressure
h) Vibration
i) Rotor position
j) Differential Expansion, Bearing metal temperature
k) Wash water flow and Wash pump discharge pressure.

Data records from the experiment

The relationships between steam chest pressure, main steam flow rate as well as the power output (load) are shown in figure 3.6 below. Steam chest pressure is plotted every four hours in a day during the turbine blade washing operation. The effectiveness of the operation can be judged by the plots, because the steam chest pressure will drop gradually and reach to a target pressure during the operation at the same load and vacuum conditions by washing away the scaling on the first stage nozzles.

Table 4.1 and Table 4.2 in chapter four illustrates the data recorded on the first and second days of the experimental set up. When the steam washing procedure was started there was no significant result that was noted in the first few hours. But with persistency there was a remarkable improvement in the steam chest pressure in the first stage of the turbine. The reduced chest pressure gave a corresponding increase in the turbine and generator loads (power output) hence the graphical illustration showed a remarkable improvement as can be seen and discussed in chapter four of this project.

It is important to always monitor and record the steam chest pressure at least thrice a day during the normal plant operation. The recording should also be plotted on a graphical manner for tracking and illustrating these changes. Such records or plots will indicate symptoms of the scaling on the first stage nozzles of the turbine. Figure 3.7 below shows for comparison purposes the clean turbine diaphragm and the damaged turbine blade nozzles caused by scaling and deposition that has occurred over time.

The whitish spots shown by the arrow indicates the silica deposition on the turbine first stage turbine nozzles which is completely embedded on the metallic diaphragm blades. The scales deposited on the diaphragms limits the clearance which is the main steam passage axially during the mechanical expansion of steam. This limitation also affects the steam chest pressure by raising it hence causing back pressure. The back pressure interferes with the forward flow of steam and gradually reducing the generator load over time.

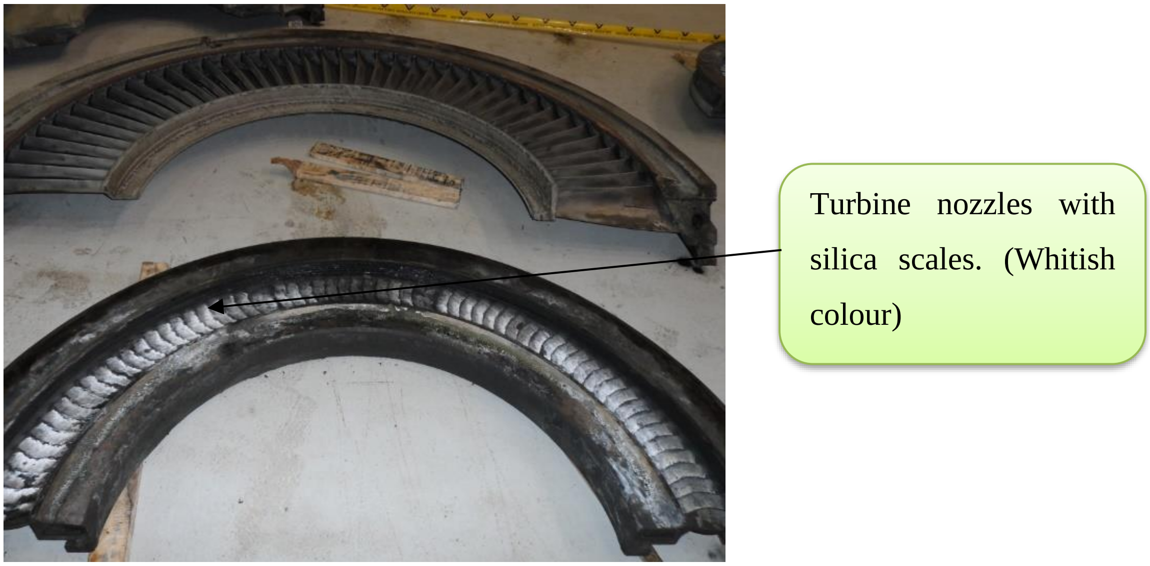


Figure 3. 5: Turbine nozzles with Silica Scales.

Inadequate steam purity from liquid-dominated or vapour-dominated geothermal resources can be detrimental to the long term economical and reliable operation of geothermal power plants.

Contaminants in the motive steam of geothermal power plants cause scale build-up in the inlet nozzles which, in time, reduces power output. There are two basic types of contaminants in geothermal steam, liquid entrainment, and volatile chemical species. Liquid entrainment can generally be resolved adequately using mechanical separators and emergency dump valves (EDV's) . The volatile species consist of slightly volatile substances such as silica, arsenic and boron, as well as highly volatile substances such as carbon dioxide, hydrogen sulphide and ammonia.

CHAPTER FOUR

RESULTS AND DISCUSSION

This Chapter mainly analyses the findings of the research study of load optimization by steam and blade washing in a flash type of power plant in the geothermal power generation. The data recorded during the experimental set up is also presented here for further analysis, interpretation and the conclusion done thereafter. The line graphs drawn from the data projects various parameters that come into play whenever generation of energy occurs in the geothermal power plant. The load generated in a geothermal power plant mainly depends on the steam chest pressure (bowl pressure), main steam flow rate, steam inlet pressure, temperature and condenser vacuum.

4.1 Data Analysis

From the experimental set up and the recorded data, the following results can be inferred and deduced.

i. The Load generated in a geothermal power plant is dependent on the following factors;
   a. Steam chest pressure (Bowl pressure).
   b. Main steam flow rate.
   c. Inlet steam pressure and temperature.
   d. Condenser vacuum (Exhaust pressure).

ii. The lower the steam chest pressure (Bowl pressure), the better the load generated at the generator (inversely proportional).

iii. The lower the condenser pressure (Exhaust pressure or Vacuum), the better the Load that is generated by the generator (Inversely proportional).

iv. Load generated is directly proportional to main steam flow rate in a geothermal power plant.

v. The Load generated in a geothermal plant is also directly proportional to the inlet steam pressure and temperature respectively.

   Table 4.1 and 4.2 below gives a record of the data collected for the analyses in the graphs.

Table 4. 1: Data Records from Experimental steam and blade washing method (Day 1)

		ITEM TO BE MEASURED			UNIT	BEFORE BLADE WASH	BLADE WASH 1	AFTER BLADE WASH 1	BLADE WASH 2	AFTER BLADE WASH 2
STEAM & BLADE WASH		Time hours			Hours	1235	1635	2035	0035	0435
	1	Generator load			**MW**	26.4	25.9	28.5	30.3	33.5
	2	Blade wash water flow			T/H	3.8	3.9	0	3.9	0
	3	Main steam flow			T/H	253.94	253.85	249.35	246.1	244.5
	4	Main steam pressure		inter-face	Bar g	4.45	4.38	4.3	4.28	4.22
				LH		4.15	4.12	4.08	4.04	4.02
				LH		4.16	4.12	4.07	4.05	4.03
	5	Main steam temperature		inter-face	C	151.34	151.5	151.6	151.7	151.0
				LH		150.3	150.1	150.3	150.4	150.3
				RH		150.3	150.1	150.3	150.5	150.3
	6	Steam chest pressure			Bar g	3.638	3.52	3.22	3.15	3.00
	7	Condenser vacuum			Bara	0.077	0.079	0.077	0.075	0.075
	8	GV position		LH	%	61%	60.5	53.3	52.2	50.8
				RH		59%	58.5	52.9	51.8	50.5
	9	Bearing metal temperature		#1	C	66.5	66.7	66.4	66.3	66.2
				#2		63.5	63.6	63.4	63.2	63.1
				#3		62	62.3	61.9	61.8	61.6
				#4		60.8	60.9	60.6	60.5	60.3
	10	Bearing vibration	#1	X	Micron P-P	18	17	14	14	14
				y		19	18	15	14	14
			#2	X		24	23	17	17	17
				y		24	24	19	18	19
			#3	X		32	32	31	31	33
				y		20	21	20	20	21
			#4	X		24	24	25	24	26
				y		29	29	29	29	32
	10	Rotor position			Mm	-0.09	-0.09	-0.11	-0.11	-0.11
	12	Differential expansion			Mm	1.11	1.11	1.15	1.16	1.24
	1	Thrust bearing metal			C	58.2	58.3	57.6	57.4	57.3

	2	temperature (Gov side)						
	13	Thrust bearing metal (gen side)	C	44.1	44.2	43.9	43.8	43.6

The Figure 4.0 Below shows the graph of Generator Load Vs the Year of Operation of the Unit.The Unit was commissioned in 2003 with a generating capacity of 35 MW.From the graph it can be seen that the Unit maintained an optimum performance for close to four years and thereafter Silica scaling started affecting the Unit.From the third year in 2006 the Unit fell short of generating its full capacity rating and this gave an indication of the silica scaling phenomenon.The unit deteriorated in generation of load to a low of 26.5 MW with an indication of further deterioration.A mitigation measure was quickly hatched and put in place in order to bring back the unit to its full generating capacity.One of the options was to shut down the unit for the physical removal of silica and this would require a total shut down. Steam washing is one of the methods that when utilised, would not require a total shut down as a stop gap measure.

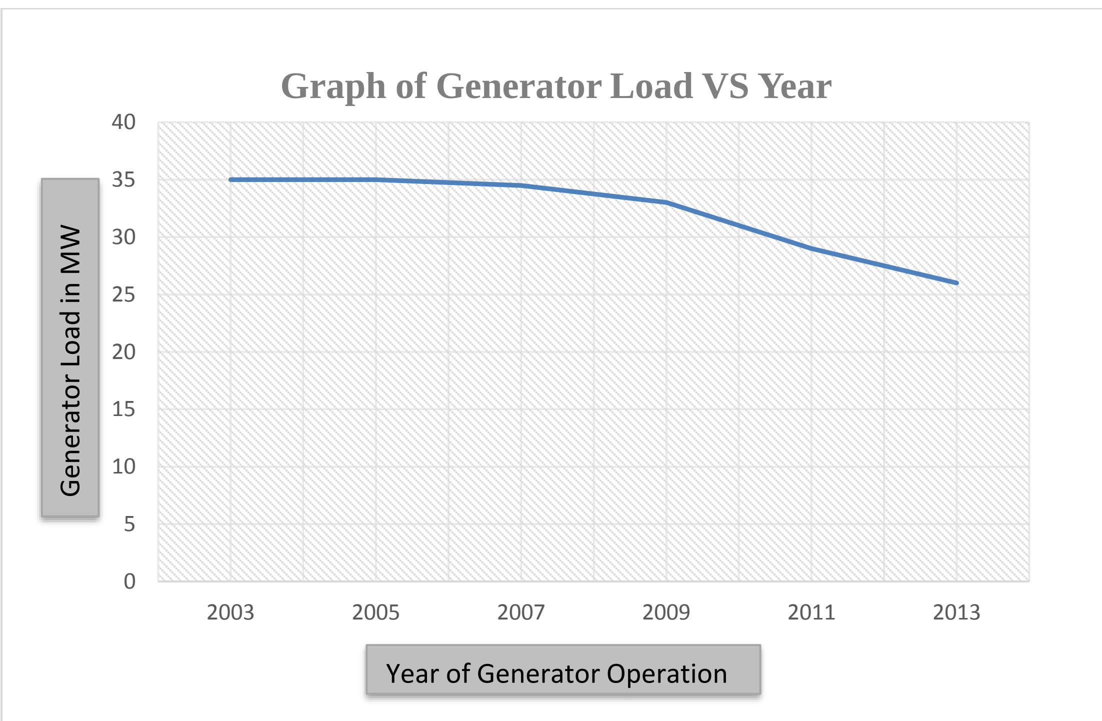


Figure 4. 1: Graph of Generator Load verses Years of Generator Operation

From the year 2012 the generator had deteriorated to aload of 26.5 MW and this stabilised for ashort while before decreasing even further.Steam and blade washing technique is a stop gap measure utilising the condensate water to clean by clearing the silica deposition on the turbine first stage blades.The condensate water is sprayed into the main steam line through aseries of nozzles atomising the water.The steam density is raised once the atomised water is introduced and this is applied to the deposition for its removal by scrubbing.

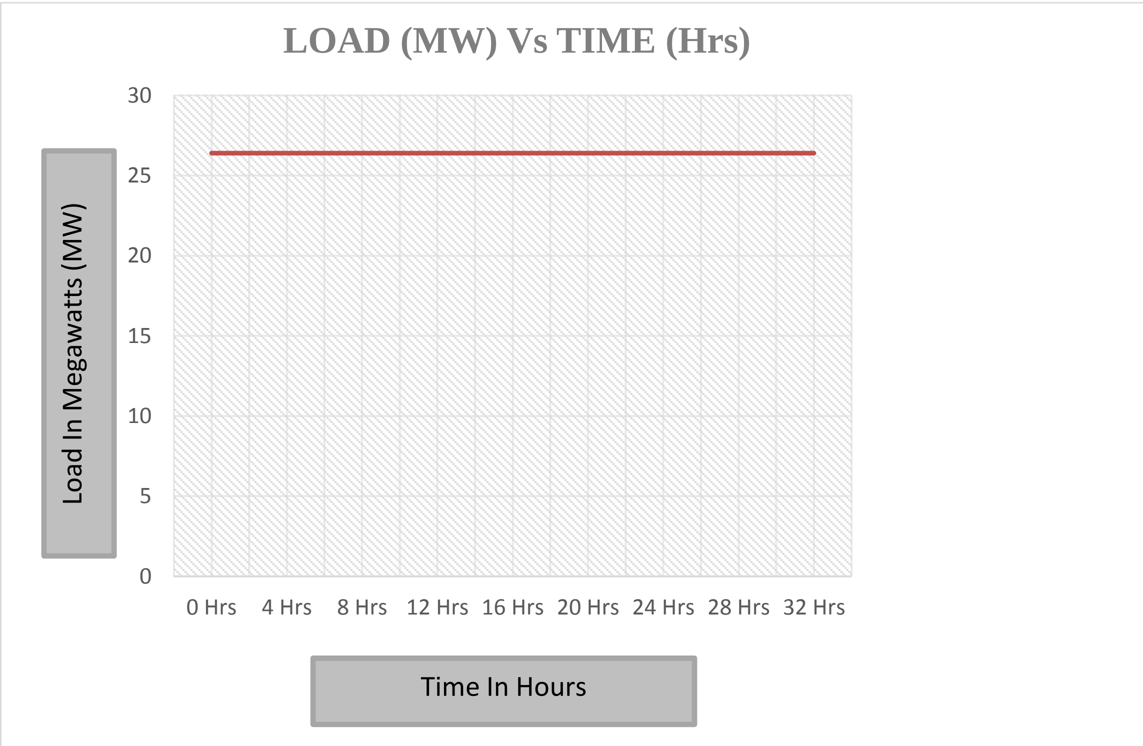


Figure 4. 2: Graph of Load vs. Time before Blade & Steam washing.

From the graph in Figure 4.1 above, the graph shows the Units recorded in the control room by the researcher together with the operator. The power plant Unit had an installed capacity of generating 35 MW but over time and owing to silica scaling the load had gradually reduced to 26.4 MW. This Load kept reducing each day a phenomenon associated with silica scaling that had contributed to an increase in steam chest pressure. This required some mitigation measures and therefore the main reason as to why steam washing ought to have been started prior to scales deposition or the turbine overhaul initiated to physically remove the silica scales.

According to the findings of this study before the blade and steam wash of the turbine at Olkaria II power station the generator load read 26.4 MW, while during the blade wash the load reduced a little bit to 25.9 MW. After the second turbine blade wash procedure, the Load recorded remained fairly unchanged (constant) at 1635 Hrs showing that there was no significant change caused by the blade washing. From the findings that were done by the researcher with the assistant of other engineers at the plant it clearly shows that the generator load decreased with 0.1% of the reading at 1635 Hrs when blade washing was started.

After a number of data readings were recorded during the course of the study and by taking the readings after every four hours, significant changes began to be recorded and this clearly proved the worth of the blade washing procedure. During the later hours of the steam washing method, positive results started being recorded as the procedure proved successful.

Table 4. 2: Data Records from Experimental steam and blade washing method (Day 2)

		ITEM TO BE MEASURED			UNIT	BEFORE BLADE WASH	BLADE WASH 1	AFTER BLADE WASH 1	BLADE WASH 2	AFTER BLADE WASH 2
STEAM & BLADE WASH		Time hours			Hours	0835	1235	1635	2035	0035
	1	Generator load			**MW**	33.5	34.10	35.22	35.12	36.5
	2	Blade wash water flow			T/H	4.0	4.0	4.0	4.0	4.0
	3	Main steam flow			T/H	241.6	235.5	230.35	228.5	225.2
	4	Main steam pressure	inter-face		Bar g	4.28	4.38	4.3	4.28	4.22
			LH			4.05	4.03	4.02	4.02	4.02
			LH			4.05	4.04	4.03	4.03	4.03
	5	Main steam temperature	inter-face		C	151.8	151.5	151.3	151.3	150.9
			LH			150.3	150.1	150.3	150.4	150.2
			RH			150.3	150.1	150.3	150.5	150.3
	6	Steam chest pressure			Bar g	3.05	3.03	2.95	2.65	2.50
	7	Condenser vacuum			Bara	0.075	0.075	0.076	0.075	0.075
	8	GV position	LH		%	50.9%	51.5	50.3	50.2	50.1
			RH			50.7%	51.5	50.5	50.4	50.2
	9	Bearing metal temperature	#1		C	66.5	66.7	66.4	66.3	66.2
			#2			63.5	63.6	63.4	63.2	63.1
			#3			62	62.3	61.9	61.8	61.6
			#4			60.8	60.9	60.6	60.5	60.3
	10	Bearing vibration	#1	X	Micron P-P	18	17	14	14	14
				y		19	18	15	14	14
			#2	X		24	23	17	17	17
				y		24	24	19	18	19
			#3	X		32	32	31	31	33
				y		20	21	20	20	21
			#4	X		24	24	25	24	26
				y		29	29	29	29	32
	10	Rotor position			Mm	-0.09	-0.09	-0.11	-0.11	-0.11
	12	Differential expansion			Mm	1.10	1.12	1.13	1.15	1.17
	12	Thrust bearing metal temperature (Gov side)			C	58.2	59.3	57.95	57.66	57.33

	13	Thrust bearing metal (gen side)	C	45.1	44.93	43.9	43.88	43.65

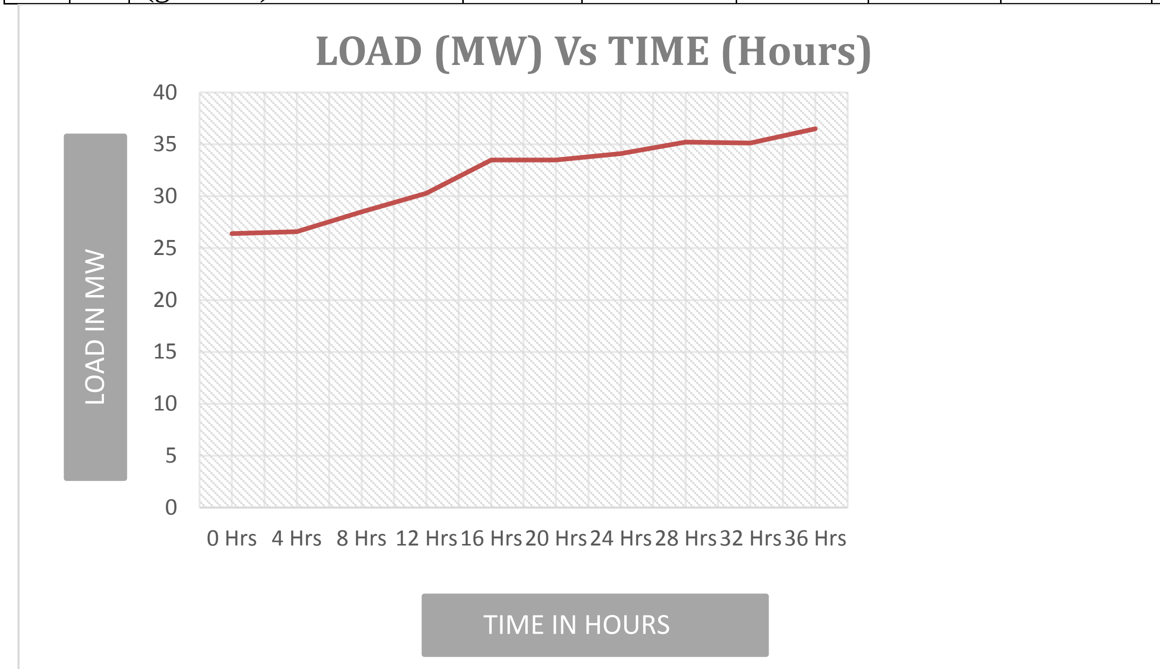


Figure 4. 3: Graph of Load vs. Time with significant Changes in Load after Blade washing

4.1.1 Main steam flow

The main steam flow according to the records in Tables 4.1 and 4.2 was 253.94 ton/hr. at 1235 hrs before the washing had begun. During the first blade wash at 1635 hrs. , the main steam flow reduced to 253.85 ton/hr. showing a steam flow rate decline of 0.09 ton/hr. This is an excellent indication as the Load generated was being recorded with reduced steam consumption. The Turbine efficiency then slightly went up as steam washing continued.

At the end of day two of the steam washing process (at 0035 hrs. on day 2), the steam flow rate had declined to 225.2 ton/hr. This is a total decline of steam consumption by up to 28.74 ton/hr. Using steam consumption alone, the overall Turbine efficiency may be calculated as follows;

Initial steam consumption =**253.94 tons/hr.**

Final steam consumption =**225.2 ton/hr**

Overall Turbine Efficiency (Using steam consumption alone) ~ **(253.94-225.2) =28.74 ton/hr**

Efficiency = **(28.74 ÷ 253.94*100) =11%**

The total decrease in the consumption has led to the Turbine increase in Efficiency of about 11**%** and this is a saving on Energy which could be put into other uses such as direct use or for well head power generators.

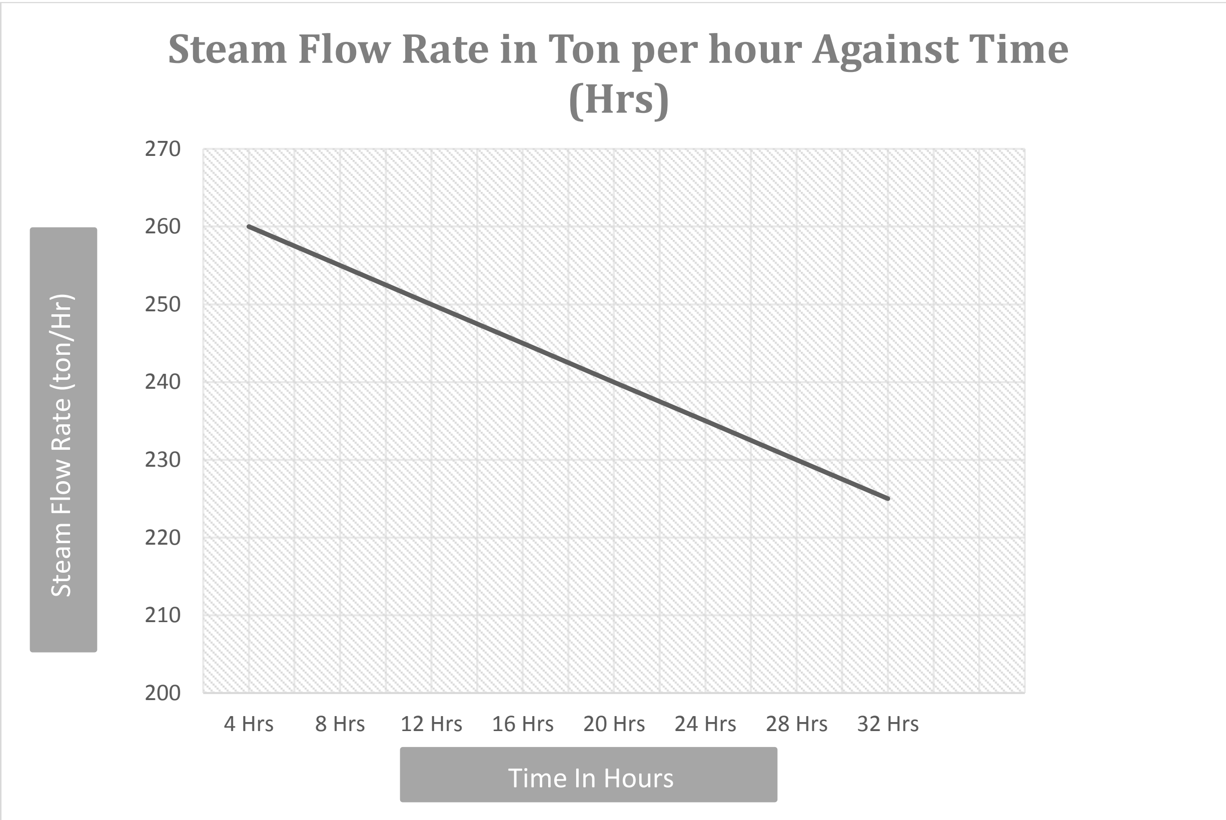


Figure 4. 4: The Graph of Steam flow rate verses Time

From the graph drawn above of Figure 4.3, the steam consumption was quite high at first in the upwards of 253 tones/hour. The steam consumption was quite high an indication that silica clogging had to a larger extent blocked most of the turbine blade nozzles. This therefore called for either a manual intervention to unclog the turbine nozzles or to initiate the steam washing process described in the preceding chapter (chapter 3). The gradual drop in the steam consumption according to the graph above meant that the turbine efficiency was being enhanced and this led to a saving in the overall steam consumption by the turbine. This steam would then be used for other uses either to be channelled for direct use (heating or green house) or for future well head power generation.

4.1.2 Steam chest pressure

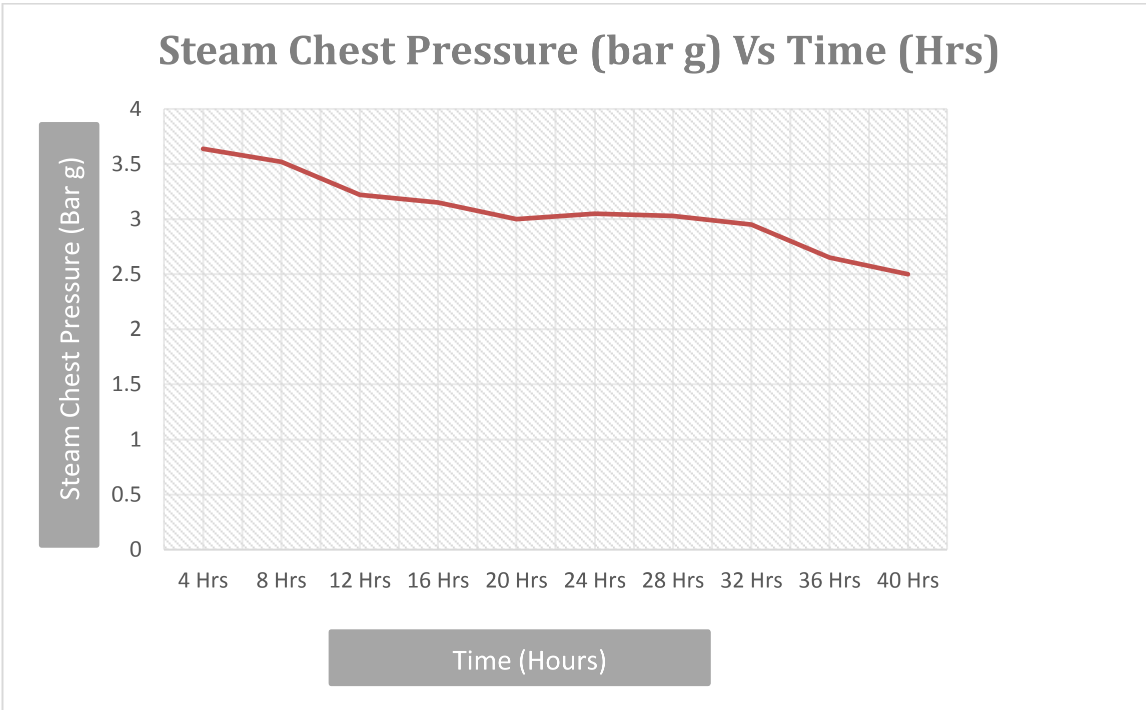


Figure 4. 5: The Graph of Steam chest pressure Verses Time

From the findings of this study as indicated in the figure 4.4 above, the recorded steam chest pressure at 1235 hrs. Was 3.638 bar g. This is a very high value of Steam chest pressure for the Turbine. The effect of having a high steam chest pressure value is that it restricts the forward passage of steam from the 1st stage Turbine blade through the other blade stages. This is because of the reduction in the clearance through which the steam is to expand while in the Turbine. This then creates a build-up of steam pressure within this region (1st Stage) and this build up is counterproductive and leads to less generated power at the generator.

At the 40th hour of the steam wash, as can be seen from the graph above (Figure 4.10), excellent results are documented. The steam chest pressure recorded was 2.5 bar g. This is a very good value as it does not restrict the steam forward passage into the 1st stage blades but at the same time provides a balance of pressure to both the Turbine blades as well as the overall balance of the whole turbine rotor.

Initial steam chest pressure =**3.638 bar g.**

Final Steam chest pressure =**2.5 bar g.**

Decline in steam chest pressure value =**1.138 bar g.**

Turbine Efficiency increase from the reduced steam chest pressure value

= (1.138÷ 3.368)*100 = 31.3% (Turbine efficiency increase)

4.2 Hypothesis test using the experimental data

4.2.1 H_{01}: Blade wash water flow has a significant effect on load optimization

According to the study findings there was a significant change in blade wash water flow on load optimization therefore blade wash water flow has a significant effect on load optimization was a positive hypothesis that was eventually proven.

4.2.2 H_{02}: Main steam flow has a significant effect on load optimization

According to the study findings there was no significant change in main steam flow on load optimization. Therefore the main steam flow has a significant effect on load optimization was a null hypothesis since the researcher was out to find out the effect of blade wash on Load generated.

The Main Steam flow recorded from the experimental data reduced as blade wash exercise continued. This was because lesser and lesser steam was now being used for load generation and not to overcome the steam chest pressure. Finally at a steam flow rate of 225.2 tons/hr., very little steam was being used to overcome the steam chest pressure and more of the steam at the Turbine rating was being directed for power generation.

So for the design of the Turbine at Olkaria II, the Turbine is supposed to use the steam with the following properties;

a) Saturated steam.
b) Steam at the initial pressure of **4.2 bar g** and
c) Saturated steam at **150.3 degrees centigrade**, at turbine inlet.
d) No use of superheated steam for the turbine.
e) Steam at almost neutral **PH** of **7.**

4.2.3 H_{03}: Steam chest Pressure has a significant effect on load optimization

According to the study findings there was a huge significant change in blade wash water flow effect on steam chest pressure and eventually on load optimization; therefore steam chest pressure has appositive effect on load generated. So the lower the steam chest pressure the more the Load generated and the higher the steam chest pressure the lower the load generated.(**See below graphs).**

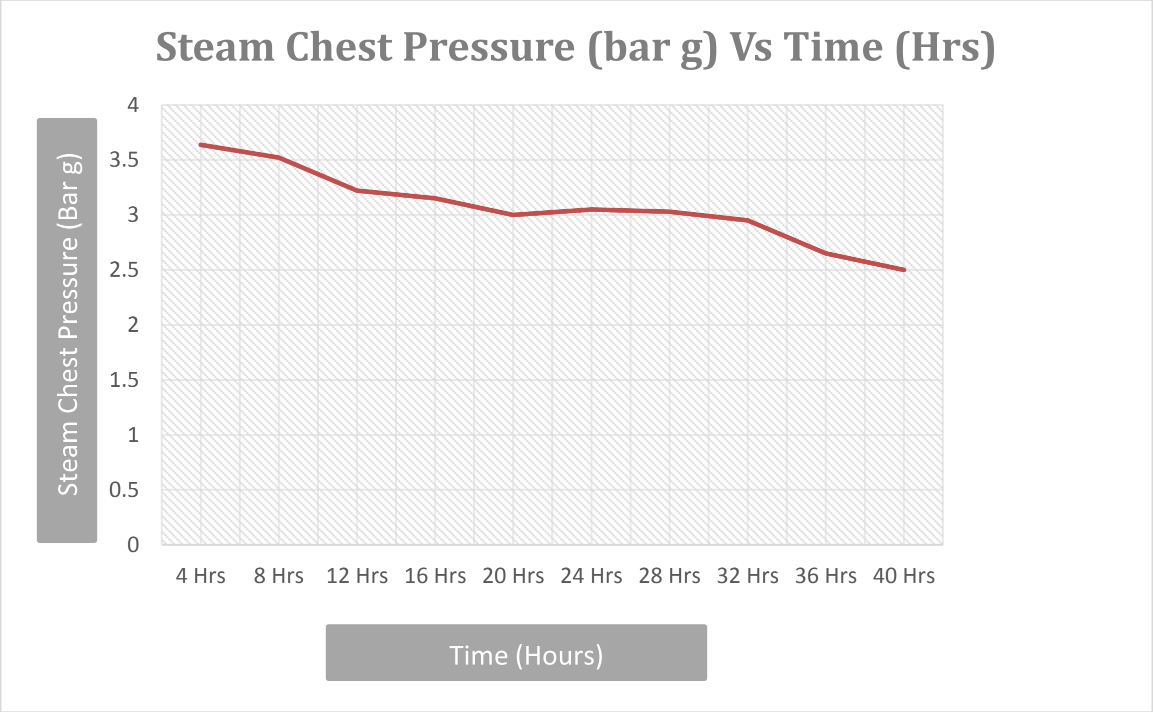


Figure 4. 6: The Graph of Steam chest pressure Verses Time

Every turbine design has got an optimal operating steam chest pressure in a steam turbine. The steam chest pressure determines the rate of expansion of steam though the various turbine blades. A higher steam chest pressure value restricts the forward expansion of steam through the first to the last turbine blades. This principle is pegged on common knowledge that a medium flows from a higher potential location to a lower potential location. Water flows from a higher dam level to a lower dam level with pressure. Electricity flows from a higher region of high potential difference to that of lower potential. The same applies to the steam theory whereby steam would flow from a region of higher steam pressure to a region of lower steam pressure.

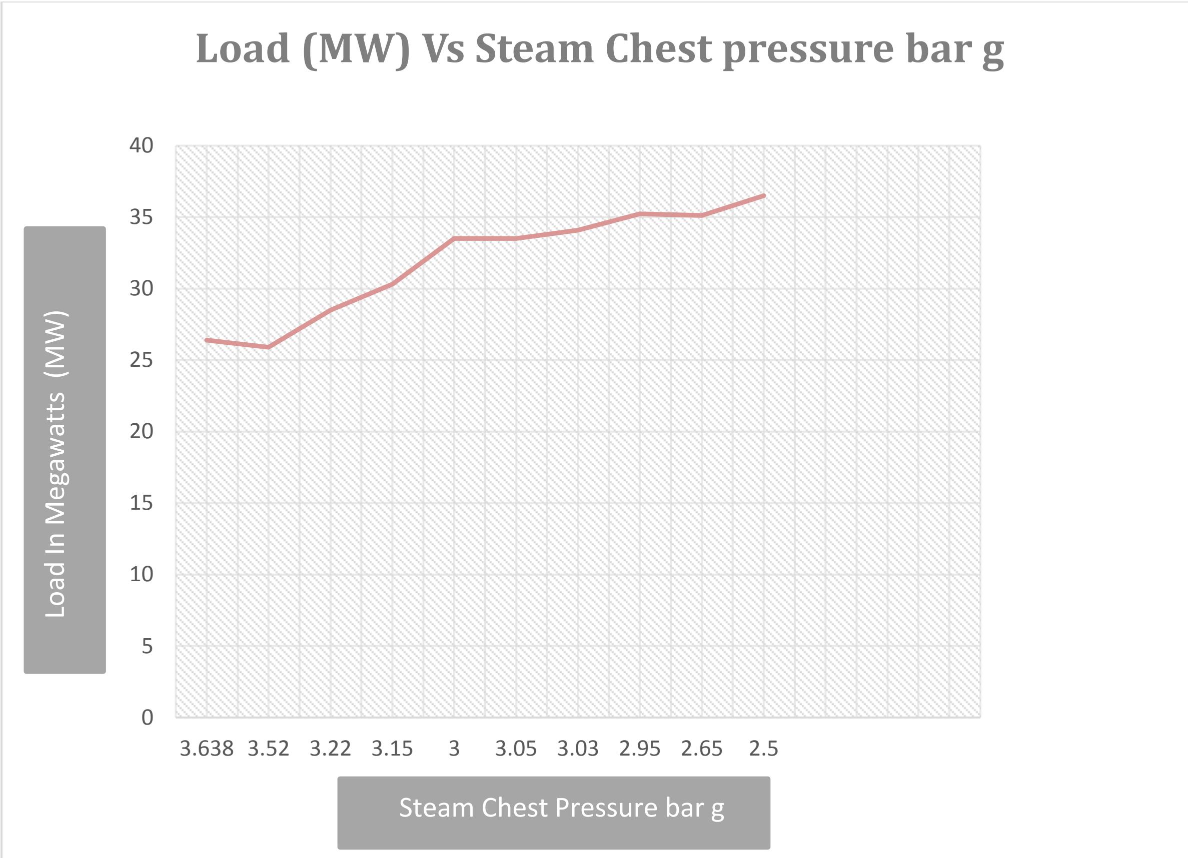


Figure 4. 7: Graph of Load (MW) Vs. Steam chest pressure (bar g)

From the graph above (Figure 4.6), the Load was recorded with every four hours of steam washing. As the steam washing progressed silica cleansing occurred and this had a positive influence on the Load generated. The Load generated was boosted by the fact that the steam chest pressure was brought down (from **3.638 bar g to 2.5 bar g**) and this made the Turbine nozzles (clearances) more opened up and therefore improved the turbine overall efficiency. The lower steam chest pressure meant cleaner turbine nozzles and this guaranteed the improved Turbine Loading of the rated turbine capacity of **35 MW**. For future turbine designs the steam washing process needs to be automated such that with every increase in the steam chest pressure by a certain value then the steam washing be started automatically to mitigate on the condition and the overall generator loading.

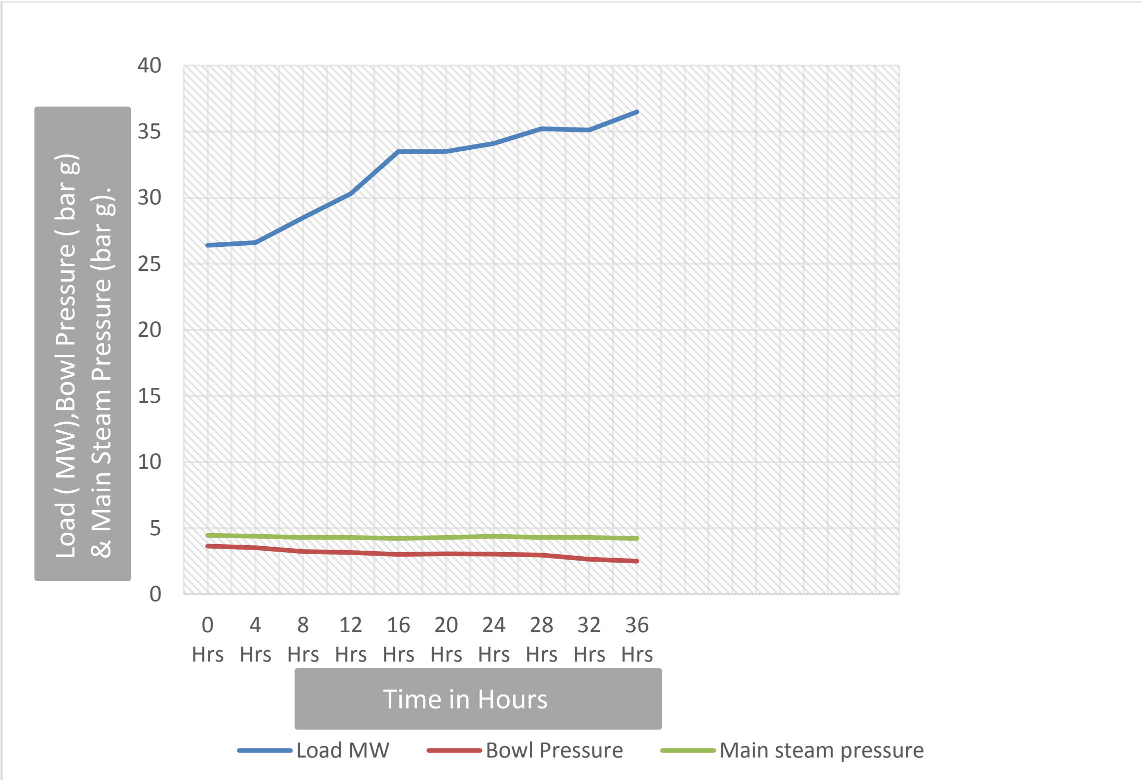


Figure 4. 8: Graph of Load, Bowl pressure and Main steam Pressure Vs Time

The graph above (Figure 4.7) represents the Load (MW), Bowl pressure (bar g) and main steam pressure (bar g) verses time in hours. As the (bowl) steam chest pressure decreased with the steam washing process, the load increased from a lower value of **26.4 MW** to the turbine rating of **35 MW** over the steam washing period. The turbine inlet condition remained fairly unchanged at a temperature of **150.3^0 C** and a pressure of **4.2 bar g** (as seen on the graph).This therefore means that the turbine is operating optimally at its rating of operating with saturated steam at **4.2 bar g** and temperature of **150.3^0 C** to give a load of **35 MW**.

Therefore, any deviation of either the steam chest pressure or excessive steam consumption by the turbine or reduced Turbine Loading would raise an alarm and necessitate the need for human intervention (cleaning of the nozzles), steam washing (blade washing) or an automated steam washing process.

CHAPTER FIVE

CONCLUSION AND RECOMMENDATIONS

This chapter discusses the conclusion made from the research design and the experimental set up and thereafter providing the requisite recommendations. The chapter also gives an overview of the whole findings and how steam and blade washing of the steam turbine was done and the conclusions deduced. It also gives a summary of the graphical illustrations, findings and inferences ready to be adopted either for implementation or to highlight possible areas for further researching by other researchers.

5.1 Summary of the Key Findings

From the findings of this study by the researcher it was realized that when the steam flows from the well in a geothermal system, scaling and corrosion takes place in the pipes, pumps and blades of the steam turbine which are carried by the flowing steam used for power generation. The scaling and deposition has been identified to be chemically formed and this would also require chemical solution as well to wash it away.

The main objective of the researcher was to develop a silica scaling mitigation methodology for enhancing power plant efficiency in Olkaria II geothermal plant. This objective was accomplished as the designed steam washing operation cannot only be used in Olkaria II geothermal power plant but on any other geothermal power plant with silica scaling menace.

The data recorded during the experimental set up clearly showed that the steam washing method is an effective method for solving the scaling phenomenon while at the same time generating the electrical energy without shutting down the plant. This can be clearly inferred in chapter 4 in the results and discussion.

The other research objective was to design an effective steam and blade washing method as a solution to silica scaling and deposition on the steam turbine blades and diaphragms. According to the findings of the study, there was a huge significant change in generator load by a continuous steam and blade washing operation hence optimizing the overall plant load and efficiency a positive hypothesis that was eventually proven.

The overall effect of steam and blade washing to the steam consumption per megawatt hour was greatly enhanced and this was found to have appositive effect on steam turbine overall performance and efficiency. The total decrease in the steam consumption led to the steam turbine increase in efficiency of about 11**%** and this is a saving on energy which can be put into other useful uses such as direct use or for well head power generation.

According to the study findings there was a huge significant change in blade wash water flow effect on steam chest pressure and therefore on overall plant efficiency; therefore a reduction in steam chest pressure has a positive effect on load generated in a geothermal power plant. So the lower the steam chest pressure the more the Load generated and the higher the steam chest pressure the lower the generator load and the plant efficiency.

The experimental steam and blade washing operation designed was used to generate the researcher's data which was recorded in tables 4.1 and 4.2. After the analyses of the data, demonstrated graphically, the overall usefulness of the operation in Olkaria II power plant was greatly enhanced and this was shown by the improved plant efficiency.

5.2 Conclusions

1. In a Geothermal power plant the following steam properties are key for the successful generation of electrical energy;
    a. Turbine inlet pressure
    b. Turbine inlet temperature
    c. Steam PH into the Turbine
    d. Saturated steam
2. From the objective of the study on the factors affecting performance of a geothermal power plant, the following factors were found to affect the plant overall performance;
    i) Steam chest pressure of the 1st stage turbine blades.
    ii) Main steam flow rate into the turbine.
    iii) Steam properties such as pressure, temperature and flow rates.
    iv) Saturated steam condition and PH.
    v) Effects of scaling on the Turbine blades.
    vi) Steam wash and blade wash effects on generated plant Load.

3. The experimental data from the Olkaria II geothermal power plant has been analysed based on the blade washing technique discussed above. The blade washing methods should be incorporated as a solution to the silica scaling in the Olkaria geothermal power plants.
4. The blade washing for silica scaling should be recorded during such methods and the data analysed for effective washing; this should thereafter be analysed for plant overall efficiency improvement.
5. The results (findings) of such data analysed to be represented graphically for a quick analysis and deductions, this would then form a ready summary for project financiers and the project implementation teams as well as the company stakeholders and investors.

5.3 Recommendations

1. Several methods should be combined with steam washing such as Physical methods. This would include methods such as the use of a higher steam separation pressure at the separators. This would ensure that the silica remains in solution without earlier precipitation of the crystals.
2. The use of chemical inhibitors should be encouraged at the well heads. These chemical inhibitors would then control the PH of the two phase fluid and thereafter chemically balancing the chemical reactions. This would then slow down by dissociating the silica component in the reaction.
3. The use of high separation pressures for Turbine inlet pressures of 4.2 bar g would require a topping up plant to take care of the wasted steam energy else a higher pressure design of Turbines to be utilized.

5.4 Research Contribution

i. The experimental set up for coming up with the recorded results and the analyses.

ii. The researcher's contribution is in the experimental data records and discussions and the graphical analysis affecting load in a geothermal power plant.

iii. The graphical representations and discussions are real time from the experimental data recorded in the data logs.

5.5 Future Research

1. The future research should be in the area of automation of steam and blade washing methods should there be any notable rise in the steam chest (bowl) pressure, then this would automatically trigger the onset of steam washing process.
2. There should be an alarm system indicating the excessive use of steam for equal load generated in the Turbine (in excess of the standard designed steam flow rate).

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APPENDIX I

Chemical composition of well discharges for Olkaria Northeast field, water phase concentration in PPM, (Wambugu, 1996)

Well No.	WHP (bar-g)	GSP (bar-g)	Enth. (kJ/kg)	pH	B	SiO_2	Na^+	K^+	Mg^{2+}	Ca^{2+}	F^-	Cl^-	SO_4^{2-}	CO_2	H_2S
OW-701	11.7	4.5	1153	9.4	3.2	686	542	125	0.2	0.7	45	714	18	128	5.3
OW-703	8.39	4.94	1257	9.2	1.2	886	710	176	0.1	0.2	83	884	24	217	1.42
OW-705	4.07	2.97	1468	9.28	-	768	534	68	0	0	64	463	17	251	11.9
OW-706	6.41	4.83	1851	9.28	3	822	510	107	0.13	0.04	68	642	32	194	3.1
OW-707	7.24	2.9	1752	9.16	4	875	520	97	0	0	53	621	140	150	8
OW-709	6.3	1.88	1954	9.45	5.5	873	830	213	0	0	164	789	53	290	4.1
OW-710	8.28	2.76	1082	8.73	1.7	396	448	98	0	0	40	517	22	198	1.4
OW-711	5.77	2.76	1233	9.14	1.3	706	554	120	0	0	70	569	29	245	6.46
OW-712	4.48	2.62	2036	9.82	4.4	796	710	82	0	0	46	590	63	155	6.8
OW-713	2.76	2.07	1696	9.14	1.5	741	517	78	0	0	30	574	26	224	7.14
OW-714	17.93	2.76	1454	9.58	3.8	850	620	118	0	0	54	642	33	186	2.7
OW-716	3.59	2.76	2645	6.77	6.9	438	535	110	0.33	0.2	28	797	90	58	0.44
OW-718	8.28	2.76	956	9.44	4.3	694	500	80	0	0	51	474	41	152	3.1
OW-719	6.55	2.9	1167	9.5	3.3	753	540	87	0.3	0.2	46	507	39	198	6
OW-721	10.34	2.07	1706	9.61	3	845	650	77	0	0	62	468	71	193	10
OW-725	6.6	-	1380	9.85	5	677	700	88	0	0	58	588	34	247	27
OW-726	6.76	2.97	1602	8.9	5	785	570	88	0	0	37	675	61	167	7.8
OW-727	5.52	3.03	1720	8.54	4.2	818	500	67	0	0	37	576	77	147	5.1