# SIGNIFICANCE OF PRESSURE LET DOWN STATION IN MITIGATING EFFECTS OF SILICA PRECIPITATION IN STEAM PIPELINES: A CASE STUDY OF OLKARIA 280MW PROJECT

Joseph Chumari[1] and Daniel Odongo[2]

[1]Kenya Electricity Generating Company PLC, Kenya

[2]Kenya Electricity Generating Company PLC, Kenya

jchumari@kengen.co.ke

**Keywords:** *PLDS, De-superheating, Silica*

## ABSTRACT

In 2012, KenGen began construction of two geothermal power plants: 140MWe Olkaria IV and 2 additional units, units 4 & 5 (Olkaria IAU) adding140MWe to Olkaria I and thereby increasing power generation in Kenya by 280MWe. The two power plants have turbine inlet pressures of 6.0 bara and 5.0 bara for Olkaria IV and Olkaria IAU respectively. This meant the steam gathering systems would also operate at that pressure.

While the project was in progress, a new optimization study reported that the deeper wells in Domes, East and North East fields which serve the power plants with steam tap fluids from reservoirs that are rich in silica. The issue was compounded by high enthalpies of the wells averaging 1790kj/kg to 2300kj/kg thereby increasing silica solubility and chances of precipitation in steam pipelines.

The concern raised resulted in KenGen incorporating Pressure Let down Stations (PLDS) in the two power plants that would maintain the steamfield pressure at the maximum but within the constraints of the already selected equipment, and then expand the steam adiabatically to drop its pressure to required values.

This paper will use the case study of these power plants to highlight the significance of the Pressure Let down Stations in controlling the effects of silica deposition in steam gathering systems.

## 1. OVERVIEW, OPTIMISATION, SILICA AND HIGH ENTHALPIES

The greater Olkaria Geothermal field is located in the southern part of the Kenyan rift about 120km North-West of the Kenyan capital, Nairobi.

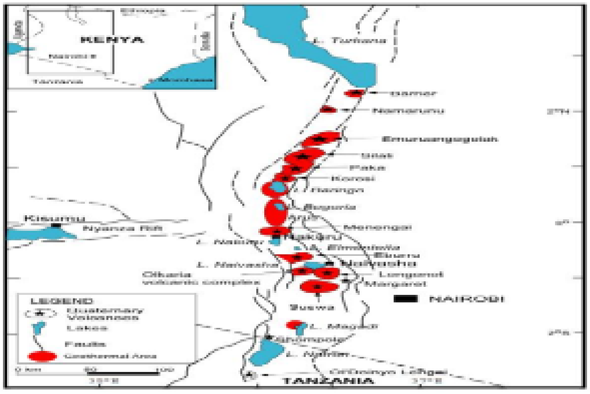


**Figure 1: Greater Geothermal Area within the Great Rift Valley of Kenya (Ofwona, 2010)**

KenGen PLC operates five power plants in Olkaria with a combined output of 590MWe and 20 wellhead steam turbine generator units with a total output of 83.0MWe.

The 280MWe power plants are served by production wells in the Domes area for Olkaria IV and East and the North East field for Olkaria IAU drilled to depths of between 2800m and 3010m.

The design concept of the steam gathering system for the 280MWe project was based on the recommendations by the feasibility study report (Westjec, 2009).

In the feasibility study report by Westjec, 2009 and which was the basis for inception of the 280MWe project, observed that the potential for silica scaling for wells within the Olkaria resource area would vary from well to well because the wells were taping from resource temperatures ranging from a low of 240$^{o}$C to a high of 340$^{o}$C. In addition, Westjec, 2009 observed that there was mixing between the upper and deeper production feed zones and this would result in excessive boiling which would increase silica saturation levels. Westjec, 2009 also noted that wells tapping from the higher temperature reservoirs would have higher risk of silica saturation and scaling.

Westjec, 2009 recommended separation pressures for the new wells based on historical observation from the existing Olkaria I&II production fields. The recommended pressure was between 4.5 to 5.0 bara and based on the wells with minimal silica scaling over the years. Only some wells were an exception and for those wells separation pressures of about 7 bara had to be maintained due to higher silica levels and higher discharge enthalpy.

As a result, Westjec, 2009 recommended separation pressures of 5 bara for the new wells within Olkaria I&II

Proceedings 42nd New Zealand Geothermal Workshop
24-26 November 2020
Waitangi, New Zealand
ISSN 2703-4275

fields and 6 bara for the wells drilled within the Domes field. In addition, Westjec, 2009 based their recommendation for separation pressures of 5 bara for wells within Olkaria I&II fields because the existing steam network was operating at a separation pressure of 5 bara therefore it would be convenient to use the same pressure rating when steam was to be shared between the existing and new power plants.

For Olkaria domes, Westjec, 2009 considered separator pressures ranging from 2, 5, 7, 10 and 13 bara. Westjec, 2009 then analyzed the potential productivity of the wells based on their optimum outputs. From their analysis, Westjec, 2009 recommended a separation pressure of 6 bara for the wells in the Domes field.

An optimization study conducted by Mannvit, 2012 of Iceland reported, during construction of the two plants, that the high concentration of dissolved silica would potentially be deposited in pipelines at the steamfield operating pressures of 6.0 bara in Olkaria IV and 5.0 bara in Olkaria IAU. To avoid silica deposition, this would necessitate increase in steamfield pressures for both power plants.

In their report for the Feasibility of Additional Generating Power Plants (Report No. 9), Mannvit, 2012 noted that selection of the optimum separator pressures should take into account the thermodynamic optimum, well productivity curves and chemical constraints in particular silica scaling. Mannvit, 2012 explained that the chemical constraints depend on the reservoir temperatures and to avoid silica scaling, separator pressure should be selected high enough to prevent silica super saturation in the geothermal fluid. Mannvit, 2012 presented the recommended minimum separation pressures for given reservoir temperatures. This is summarized in Table 1:

| No | Resource Temperature in °C | Recommended Minimum Separation Pressure in bara |
|---|---|---|
| 1 | 240 | 3 |
| 2 | 260 | 6 |
| 3 | 280 | 10 |
| 4 | 300 | 15 |
| 5 | 320 | 21 |

**Table 1: Minimum Separation Pressures Per Resource Temperatures (Mannvit, 2012)**

To ensure that the original power plant interface steam flow rates and operating pressures remained unchanged, a permanent solution would be to operate the steamfield at high pressure, and to install inline throttling devices (pressure let-down valves) near the power plant interface. Olkaria IAU steamfield would operate at 11.2 bara and Olkaria IV at 11.6 bara.

The installation of pressure let-down valves at the steamfield power plant interface, however, would result to superheated steam at 170°C in Olkaria IV and 166°C in Olkaria IAU, which exceeds the allowable limit of steam dryness and maximum steam superheat of >99.8%, and <2.5°C respectively for the interface in the two power plants.

There was a range of different approaches to addressing this issue all with different implications. KenGen PLC elected to implement a temporary solution whilst delivering on-specification, saturated, low pressure steam to the turbine inlets.

## 2. SOLUTION: PRESSURE LET-DOWN STATION

There are four steam pipelines at the interface of each of the two power plants from individual separating stations.

Each of the four steam lines running through the pressure let-down station contains:

- a DN500 segmented ball type valve with noise attenuating trim and pneumatic actuator (Figure 2),
- an in-line silencer to reduce the noise to an acceptable level (Figure 3), and
- condensate drain pots to collect excess water injected into the system.(Figure 5).

**Figure 2: One of the let-down LDVs as observed during an annual inspection.**

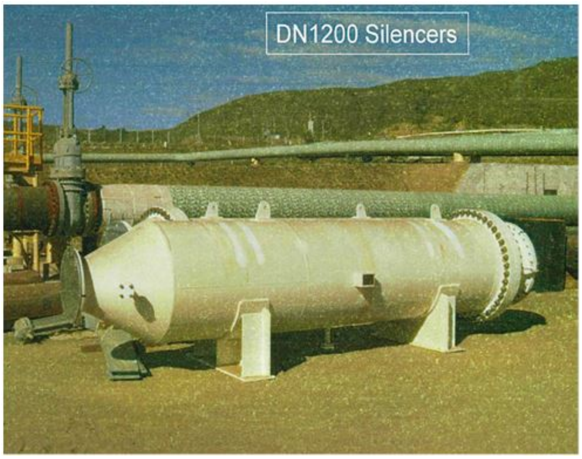


**Figure 3: One of the silencers prior to installation.**


ISSN 2703-4275

The overall pressure let-down station comprises of the four steam pipeline system valves and a de-superheating water (DSW) system applying ratio flow control loop.

High pressure steam is supplied at a nominal pressure of 11.6 bara and 11.0 bara and reduced to 6.0 bara and 5.0 bara at the power plant interface via the PLDS for Olkaria IV and Olkaria IAU respectively.

### 2.1 De-superheating System

The enthalpy of steam upstream of the let-down valves is the same as the enthalpy of steam just downstream of the let-down valve. With reduction of steam pressure after the pressure let-down valves, the steam becomes superheated.

Downstream of the PLDS, de-superheating water, DSW (power plant condensate) can be injected into the steam piping to achieve near saturated steam conditions at the power plant interface.

The DSW system consists of supply, storage, pumping and distribution elements with pressure, level and flow controllers.

Excess water can be injected to maximize the opportunity for the steam and water to reach equilibrium before the liquid has to be removed from the system via the interface CDPs or the power plant scrubbers, and to prevent dryout of the impurities in the water. An excess wetness value may be selected by the operator. The design water injection rate targets 1% excess wetness above that required for saturated steam. This water injection rate corresponds to 180% of the water flow rate required to achieve saturated conditions.

### 2.2 DSW Supply

Water for the suction of the DSW pumps can be taken from either the power plant condensate circuit (hot well pump discharge) or a raw water tank. The primary source was to be the power plant condensate as this water has low dissolved oxygen and relatively low dissolved solids.

Water pressure was to be measured by a transmitter located on the suction header of the pumps. If the condensate supply pressure were to fall below the setpoint, the raw water tank discharge valve would open, allowing water to be supplied from the tank, thus allowing uninterrupted flow of water to the de-superheating system in the event of power plant condensate pressure reduction. The liquid pressure available at the power plant interface was to be at least 0.8 barg.

### 2.3 DSW Pumps

At the Olkaria IV and Olkaria IAU interfaces, 3×50% pumps supply water to the de-superheating spray nozzles via flow control valves.

The set point for the water flow control has a minimum allowable value corresponding to the minimum flow requirement for the nozzles and to prevent damage to the pump.

The Olkaria IV and Olkaria IAU interface DSW pumps are each sized to deliver 50% of the normal required flow of 19 tph (Olkaria IV) and 23 tph (Olkaria IAU).

If one duty pump fails or trips, the standby pump has been configured to start without manual intervention.

**Figure 4: DSW Pumps in Olkaria IAU.**

### 2.4 DSW Injection

At the Olkaria IV and Olkaria IAU interfaces, 3×50% pumps supply water to the de-superheating spray nozzles via two parallel flow measurement and control systems (one for each power plant unit). Each flow controller modulates the duty FCV to achieve the required water flow set point to provide wet steam to the power plant unit.

### 2.5 Condensate drain pot level control

Four condensate pots (CDPs) were located at the interfaces of both Olkaria IV and Olkaria IAU immediately upstream of the steamfield interface with the power plant. A level transmitter and high level switch were installed on each condensate pot.

During normal operation, the steam will be wet and the CDP has been designed to operate full; water flows like a fine mist over the pot and up the vertical legs. During low steam flows, the velocity may not be sufficient to carry water up the vertical leg hence a water level must be maintained in the pipe. This introduces a risk at low flow that a water slug may form, potentially causing damage to the piping or the scrubber downstream.

To prevent this from occurring, a level transmitter has been set to open the level control valve (LCV) installed on the drain pot to maintain the level within the pot. A high level switch has been set to open the LCV to maintain the level in the drain pot.


ISSN 2703-4275

**Figure 5: One of the CDPs with level control.**

## 3. CONCLUSIONS

The Pressure Let Down Station provided a temporary reprieve for KenGen PLC to allow the steamfield to be operated at a higher pressure without necessarily changing the design that would have been expensive in terms of time and cost. This solution can be used for steamfields that experience change in reservoir conditions and still need to run an existing plant. The control system developed was simple to integrate into the existing system, and maintenance costs have been low.

With the PLDs in place, the Olkaria 280MWe steamfield has experienced low silica precipitation that was evident during planned inspection of the separator vessels, throttling valves and brine re-injection systems.

## REFERENCES


Mannvit Consortium, *Feasibility study for development of the KenGen Olkaria concession area*, Report no. 9, feasibility of additional units. (2012).

KenGen PLC, Steamfield operating pressure increase; interface let down station options study, internal report, ZP00700-AGGG-EPG-RPT-0006, (2013).

Ofwona, C.O.: Olkaria I reservoir response to 28 years of production. *Proc. World Geothermal Congress 2010*, Bali, Indonesia (2010).

Westjec: West Japan Engineering Consultants *Feasibility study Report for New unit*, Olkaria Optimization Study, Phase II, (2009).