TURBINE SCALING

Chris Morris[1] and Ed Mroczek[2]

[1]Contact Energy, Wairakei Power Station, Private Bag 2001, Taupo 3352, New Zealand

[2] Wairakei Research Centre, GNS Science, Private Bag 2000, Taupo 3352, New Zealand

chris.morris@contactenergy.co.nz, e.mroczek@gns.cri.nz

Keywords: *steam turbine, scaling, deposition, pipeline scrubbing, steam sampling.*

ABSTRACT

Scaling, or mineral deposition, in geothermal turbines is an industry-wide problem. It is caused by the superheating of mineralised wet steam as it passes through the turbine nozzles. The superheat conditions result from the normal turbine operating process and cannot be eliminated without significant detrimental effects to performance. The steam supply has a small fraction of water carryover from separator breakdown. This is normally removed by pipeline scrubbing or demisters but these are not totally effective. Low drainpot efficiency exacerbates the problem. A sample of wet steam collected by isokinetic probes is rarely representative of the total impurities. The authors propose a more effective practical standard to assess geothermal steam cleanliness.

1. TURBINE SCALING

1.1 Overview

Scaling is a problem in many geothermal power station turbines. The scale is from the minerals originally dissolved in the geothermal well fluid. When steam is separated from the water in the separators, the non-volatile constituents stay with the water and not in dry steam. Turbine deposition primarily occurs in the turbine nozzles (Fig.1).

Many stations have some form of steam cleaning after separation to remove the carryover. However, industry experience is that in most plant, this scrubbing is inadequate, as the consequent scaling proves. Doing a literature search brings up many papers from many stations with problems. Our anecdotal observation is that scaling has become more of an issue. Newer stations, probably not coincidentally, generally have bigger, higher mass flowrate separators that are closer to station than original installations.

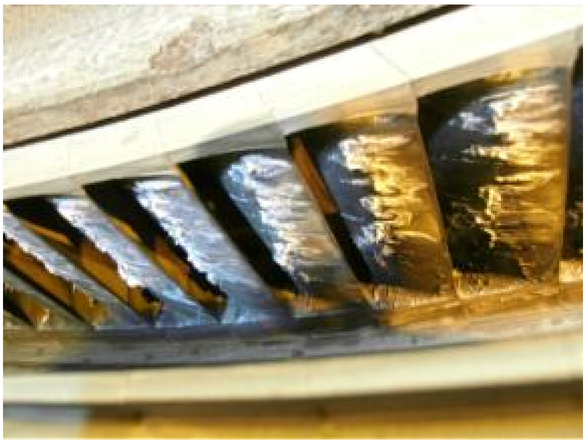

Fig 1: Typical scale deposition in turbine nozzles

Here we set out the physics, chemistry and the experimental/ practical data around turbine scaling. This is to increase understanding about the causes of scaling and the possible solutions.

1.2 Turbine Thermodynamics

Turbines extract energy from steam by a series of expansions through stages, where the expansion is through fixed blading ports, increasing the velocity, and the rotor blades use the velocity to turn (Fig. 2). The fixed blade expansion is at near constant entropy. This means that for the bulk steam near the saturation line, the expansion through the first stage of the fixed blading (nozzles) lowers the steam quality from close to the saturation line into wetness. The enthalpy drop provides the energy for the kinetic energy increase, with the steam accelerated up to around sonic velocities. Fine water droplets (typical diameter ~0.1 micron) form in the steam. Jonas (1995) identified that heterogeneous nucleation occurred around the mineral particles, even when they were present in only µg/kg concentrations. These droplets are both smaller and more easily formed by homogenous ones from the spontaneous condensation of pure water. The turbulence of the flow flings the water droplets against the port walls where it forms a moving film about 10 microns thick.

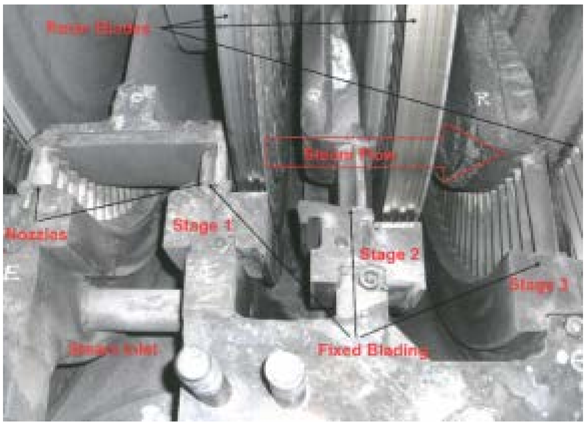

Fig 2 Turbine nomenclature used in this paper. A stage is a set of fixed and rotor blades. The nozzles are the first stage's fixed blading. The vanes are the individual blades in the fixed blading.

Figure 3 is from the Jonas 1995 paper. It correctly identified where the deposition forms, though his work was on boiler plant, not geothermal turbines. His caption only references sodium chloride, but ammonia and silica are specifically identified as nucleation species in the diagram and the text. As Dooley (1997 & 1999) reported, the slow moving steam near the port walls is in superheat from the flow stagnation. This will dry out the water that is a film on the walls. Any minerals in the water will be left behind as a deposit.

As the scale builds, the pressure drop across the nozzles increases. This increases the drying potential of any water film on the walls. The chloride deposition and brine is very corrosive and will rapidly pit the nozzle vane surface, making it easier for deposition to occur and stick. Amorphous silica is much less soluble than chloride salts so deposit first. Although deposited silica can in some cases protect the blades from corrosion, the build up and damage can be more severe as this scale does not easily re-dissolve.

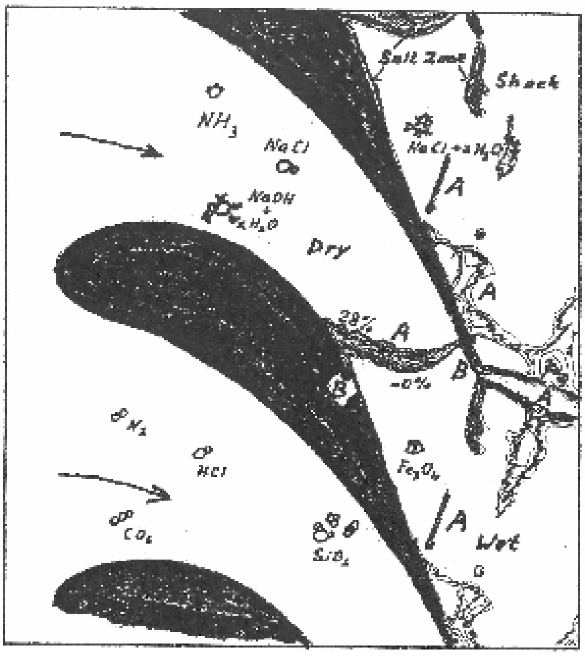

Fig 3: Figure 6 from Jonas (1995) captioned: Steam impurities in the blade path with transonic flow and condensation – A and B are zones of concentrated NaCl solutions.

Geothermal turbines are generally designed so that the inlet steam is just below the saturation line (<0.05% wet) when the governor valves are fully open. If the valves are throttled, the steam coming may be in superheat. This will dry out any minerals in the water accompanying the steam, giving more nucleation particles. Conversely, if the inlet steam is wetter than design, then the degree of superheat decreases. By the time the inlet steam is about 1.5% wet, there would be no superheat potential in the nozzles on an impulse turbine (0.75% for a reaction turbine).

Because the flow of wet steam into a turbine is dynamic, especially as load or steam supply changes, then the fluid conditions in the deposition region can vary between superheat and wet. That would mean that deposits are washed off after formation. This alternating deposition/ washing is why the deposition often have flow lines in it. The washed particles don’t necessarily redissolve but can act as abrasive paste to damage downstream components. Alternatively, the deposition can redissolve from the condensation when a turbine is shut down and restarted.

Assuming the steam supply is near design conditions, the steam at the first stage rotor blades will be near the Wilson Zone. That means that little collectable water would be present. As a consequence of this, the turbine may be designed with minimal provision for interstage drainage. This can have damaging erosion consequences if the inlet steam is wet or turbine washing is done to remove deposition.

1.3 Turbine performance effects

The usual consequence of scaling is that power output decreases. This is because the inlet pressure is generally fixed as is the steam flow, hence MW, are set by the choking flow conditions through the nozzles. Fig. 4 shows the generation data of a turbine, where it lost 0.5% of its rated output per day from scaling after the steam washing stopped. This was an extreme case. The effects of scaling more typically take months to years for the reduced generation to be noticeable.

Industry perceptions are that scale has to be significant (greater than 3mm thick) before it affects output. When turbines are dismantled, the scale is often thicker than this, and in some cases, partially blocking the nozzles. The perceptions are wrong. Scale is a rough irregular deposit, so it does not take much scale to have an effect on the performance of the machine. It does not have to restrict the throat area. The increase in surface roughness has an effect.

If the turbine inlet section is not of optimized design, the pressure drop can cause deposition upstream of the vanes. If the turbine is operated under part load conditions, the throttling across the governor valves can significantly increase the superheat available. This can extend the location of the deposition into the 1st stage rotor blades, or even the second stage nozzles. Reaction turbines can have deposition in the first stage rotor blades because of the pressure drop across them. Material can also be deposited on the latter stage vanes and blades. This is often very high in silica. It is rarely formed in situ but consists of deposition that has broken off the nozzles, then accumulated in areas where the velocity is relatively slower.

2. STEAM EQUIPMENT

2.1 Separator Breakdown

Separators are not 100% efficient (Zarrouk, 2015). There will always be some carryover of water with the steam. The amount of carryover depends on a number of factors, of which steam velocity into the separator, the flow regime of the inlet fluid, and the inlet entry spiral design are known to have significant effects (Zarrouk, 2015). It is also believed that separator diameter has an influence, though this parameter has not been comprehensively investigated.

Typically, separators are quoted at about 99.995% efficient at their design point. The design point is usually expressed in terms of mass flow, enthalpy and pressure but not the inlet two phase flow regime. Though the separation efficiency sounds impressive, the carryover is substantial. For 100t/h steam flow and the above quoted separator efficiency, there is 5kg/h carryover.

The efficiency is often only computer modeled or determined from steam sampling, not validated by field trials. This latter method would be done by using condensate or total mass flow samples. It is likely that true efficiency may be significantly lower, as internal inspections of separators often show silica precipitation in the steam tube. This is from the carryover. Though some silica may deposit here, most of it and the other dissolved components continue in the fluid stream.

2.2 Scrubbing / Demisters

Scrubbing and demisting are often treated as synonymous terms. However, scrubbing is where water is sprayed into the steam, followed by downstream separation to dry the steam while demisters don't have the water addition.

To clean up the separator steam, scrubbing is needed. Historically, this was inadvertently achieved by the long lengths of pipelines between the separators and the station. The heat losses by the relatively inefficient insulation caused condensation which flowed along the pipe walls. This was removed by drainpots. Fig. 5 shows a mineralized discharge from a drainpot trap. With modern pipeline designs and insulation, condensation loads are in the order of 1kg/h per metre of pipe. This is higher if the insulation is incomplete or in poor condition. Alternatively, it is lower if there is a pressure drop in the line like when the line is overloaded.

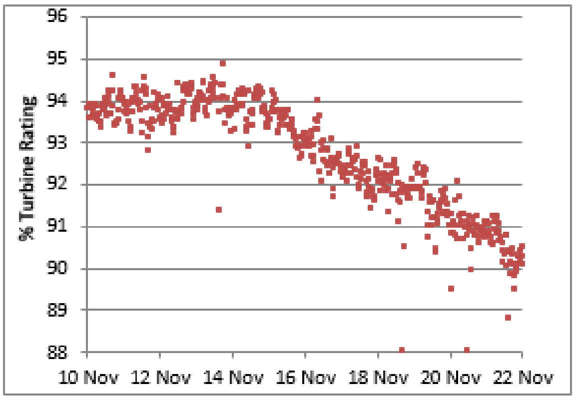

Fig 4: Generation of turbine showing output decline from scaling after steam scrubbing stopped.

Tests done forty years ago showed that drainpots needed to be deep, have an internal baffle, and at least 60% of the pipe diameter to be effective (Lee, 1982). The other factor is larger diameter lines need to be longer to allow them to scrub, especially with the high efficiency insulation (Brown & Bacon 2009). Unfortunately, these lessons have been lost by many current pipeline designers. It is also known that high steam velocities result in entrainment of mist in the steam, reducing the effectiveness of pipeline scrubbing. This is well known, but apparently has not been researched and quantified.

If a separator gives an output steam flow of 360t/h and is 99.95% efficient, then the mineralized water carryover with the steam is 180kg/h. Using standardized heat loss equations for lagged pipework and Wairakei chemistry, this will give a concentration of about 90mg/kg Na if the first drainpot is about 100m away from the separator. From then on, drainpot efficiency is the main determinant of the scrubbing efficiency. With 90% efficiency, and assuming continued 100m spacing of the drainpots, it only takes a further 300m for the steam trap discharge to be less than 0.1mg/kg sodium. However, 75% efficient takes 500m to reach 0.1mg/kg and 50%, 1km. Lee reported some efficiencies as low as 40%. At this low level, the steam would be very wet, even just after a drainpot. Many modern design drainpots are both low efficiency and sparse, so little effective scrubbing of the steam is achieved.

Modern stations with centralised separation plants and multi-stage flash have moved the stations closer to the separators. As a consequence, line scrubbing is no longer effective. The separators are also pushed closer to their design performance limits so there is more carryover.

To clean up this steam, demisters are typically installed. At some plant, scrubbing sprays are also installed upstream of the demisters to assist mineralised water removal. The mixing of the steam and spray water is very dependent on droplet size and steam velocity. Performance tests have indicated demisters are not very effective at removing water from the steam. Adiprana (2010) reports on a station that has demisters also having scaling. The authors know of others that have similar problems.

Scrubbing reduces the amount of steam available to station. It also can introduce more contaminants unless the water is clean and deoxygenated. Using scrubbers and demisters is only partially successful, as many plants that have steam cleaning continue to have turbine scaling (Kubiak 1989, Parmono 2010, Adiprana 2010, Richardson 2013). The equipment cannot always be relied upon to be effective.

2.3 Carryover is Needed

Although turbine scaling must be minimized, the steam cannot be too clean if pipeline corrosion is to be avoided. This is because if there is only clean condensate present, a protective silica coating on the steam pipes cannot form. Iron reacts with condensate to form magnetite, usually in association with pyrite due to the presence of hydrogen sulphide. However, in very clean condensate, the normally protective magnetite scale is not stable and redissolves with the formation of fresh condensate. The corrosion chemistry of the steam line corrosion and beneficial effect of silica is well understood (Giggenbach 1979; Lichti & Bacon, 2009). Consequently, corrosion patches will occur and these slowly migrate upstream, deepening as they go. It happened at Wairakei in the mid 70s and resulted in some sections of steam pipeline having to be replaced. The cause was the steam production moving from the Eastern Borefield to the Western borefield. The resulting long lengths of inefficiently insulated lines allowed high levels of condensation for line scrubbing.

The solution, though it seems counter-intuitive, was to inject small quantities of separated water (brine) into the lines. Flow rates were adjusted until there was about 1mg/kg sodium in the condensate at the Anchor 1 pots (Lichti and Bacon, 1998). This did cause some turbine scaling, but it was at manageable levels.

Fig. 5: The evaporation deposits show it does not need chemical analysis to see that there is still significant mineralization in this trap's discharge.

2.4 Dry Steam Wells

Many high enthalpy wells are not truly dry at the feed zone. However, with the pressure drop up the well, superheat conditions occur. The mineralised water that is part of the steam dries out, leaving these evaporated micron sized particles of silica and salt. These dust particles travel at the velocity of the steam, are very abrasive and corrosive where they deposit (because they are ~400kmg/kg chloride). They also can't easily be scrubbed out of the "dry" steam. This dust problem is found in other fields with high enthalpy discharges.

The only way Wairakei has found to effectively deal with this problem is to have the dry steam wells put into two phase lines. This mixture goes to the separators where the particles remain in the water. Another solution is less efficient lagging and slower steam velocities to allow pipeline scrubbing.

3. STEAM ANALYSIS

3.1 Online Detection of Deposition Risk

The old standard quoted for Wairakei was about 1mg/kg sodium in the condensate at the drainpots just before the steam goes into station. Sodium was chosen, not only because it is at high concentration in the carryover water but it can be easily and accurately analyzed in industrial plant by flame emission spectroscopy to low detection limits (10µg/kg). It is also possible to analyze the condensate continuously. Detection limits achievable in the NZGAL Laboratory are listed in Table 1.

Other analytical techniques in use and proven at thermal plant are sodium analysis using ion specific electrodes or inferring steam purity by conductivity after cation exchange. However, the need for ion exchange columns in the latter and degassing of condensate required for the former can complicate the procedure (David Addison, Pers. Comm.). This may be an area that could be usefully explored by a station chemist.

The very low concentration of dissolved constituents means that the field sampling programme must include a rigorous QA plan so that a minimum number of samples are collected to adequately characterize the existing conditions and determine the limits of variability and sampling and analytical errors. This is typically achieved through judicious use of replicate and split samples. To avoid contamination scrupulous attention is required for sample collection and handling especially ensuring equipment is clean and adequately flushed between samples.

In wet steam at normal geothermal pressures, there is almost complete partitioning of the solids into the water phase. This includes silica and chloride.

Table 1: Detection limits and of analytical methods for low level constituents in steam condensate (New Zealand Geothermal Analytical Laboratory, 2014)

Analyte	mg/L	Method
Sodium	0.005	Atomic Absorption Spectrometry*, APHA 3500-Na B 22nd Edition 2012
Chloride	0.01	Ion Chromatography, APHA 4110-B 22nd Edition 2012
Silica	0.05	ICP-OES, Alpha 3120-B 22nd Edition 2012

* a high intensity light source machine used by NZGAL allows Na to be analysed by atomic absorption to low levels.

Some stations do continuous monitoring of steam through fixed isokinetic probes in the steam pipes. In work done on two steam lines at Wairakei in 2007, it was shown steam isokinetic samples gives markedly optimistic data (orders of magnitude difference) on true steam quality (Table 2). The results have been confirmed by comprehensive testing on other sets of steam lines.

The poor sampling result is because the mineralised water from carryover and scrubbing is often close to, or on the walls of the pipelines as a microns thick layer. This is not where the steam or isokinetic probes sample from. Adapting steam flow measuring equipment to take wall samples will not be representative because the water flows at a different speed to the steam. The main water flow is on the pipe floor (Fig. 6) but can also flow around the pipe. These issues, plus the high partitioning of the dissolved solids into the water, is why steam trap samples were adopted instead of isokinetic probe samples for gauging steam quality at Wairakei. The probes are recommended to measure flows in long straight vertical pipes that flow downwards. This is not a common configuration on geothermal fields

Theoretically, the drainpot flows could be added back into the total flow and the overall fluid concentrations recalculated, but this assumes the traps are very efficient at removing the water. Unfortunately, most aren't and there is significant carry through.

The easiest way and most accurate method to measure steam quality is by tracer dilution using a tracer not found naturally in the water. The drain flows are also measured. From the data, a mass and heat balance can be done.

The old style deep, baffled drainpots do trap the water and they are easily sampled. If the trap discharge sample is cooled before collection, then there is no flash fraction correction needed. However, many modern drainpot designs do not efficiently trap and remove the water, so the water quantity from them is diminished. This and the shorter pipeline lengths means the carryover and any additional condensate can be very significant.

With modern analysis techniques and shorter pipeline lengths within station, the acceptable steam purity is now set at 0.1mg/kg sodium at the last steam line drainpot trap before the turbine. This translates to about 0.3mg/kg TDS. Correlating data indicates that when the sodium concentration is at the stated level, then there is no significant scaling in the nozzles. Because of this, it has been adopted as a de facto standard at Wairakei and the other Geothermal Group stations. There is no theoretical basis to this number, only practical experience. However, it should be noted that if the steam is 0.5% wet, this equates to a TDS of 1.5µg/kg. That is comparable with the cleanliness limits required for boiler fed turbines (IAPWS 2013).

From the data in Table 2; even if the steam is only 0.5% wet and the sodium in the steam is at the detection limit, most of the minerals are in the condensate.

3.2 Superheat in Steam Pipelines

This is a similar problem to the dry steam wells. At high flow rates, or if there is a large restriction, the pressure drop will put the steam in superheat. With modern insulation, this can be a real issue. Superheat will turn the carryover into sub-micron sized evaporate dust. The particles are both abrasive in motion and corrosive where they deposit. They will travel within the steam flow and can't easily be removed. The only effective way of dealing with problem is to carefully monitor the lines, ensuring that superheat does not occur. The draintrap flow rates can indicate if there is a problem. For some lines, control has to be by restricting the maximum flow.

3.3 Volatile Silica

Richardson et al (2013) have postulated that the deposition on turbines is from volatile silica. This is because at high temperatures, silica is present in the steam phase when the steam is superheated (IAPWS, 2013). The most recent reassessment of amorphous silica solubility in steam at saturated vapour pressure is Plyasunov (2012). It shows that steam silica solubility decreases significantly as temperatures decrease.

Table 2: 1200mm diameter steam pipe sampling

	Iso-kinetic Traverse Point (from wall) mm	Silica mg/kg	Sodium mg/kg
1.	53	<0.05	<0.02
2.	175.5	<0.05	<0.02
3.	355.8	<0.05	<0.02
4.	846.2	<0.05	<0.02
5.	1026.5	<0.05	<0.02
6.	1149	<0.05	<0.02
7.	Drainpot	1.4	4.9

At low separation pressures a Wairakei fluid separator operating at ~ 4.8bg with a typical 99.9% efficiency will put about 0.5mg/kg silica in the steam with next to no contribution from volatile silica whereas from steam solubility could only occur at separation pressure ~ 40ba.

So although at high separation pressures, the volatile silica may make a significant contribution to the total, the driving force is for volatile silica to strongly partition into the water phase. The exception is where the steam is superheated and no water is present, in which case the constituents are transported in the vapour phase or as solid particulates as discussed in Section 3.2.

Fig. 6: Steam pipe after bends (flow towards camera) showing water flow spiralling around pipe as well as along the floor. Isokinetic probes would not pick up this water.

Drainpot condensate analyses show significant amounts of sodium (Table 2) and other cations. Except for boron, which also has increased solubility in steam (Glover, 1988), these components are not from partitioning into vapour but solely from carryover.

In the author's experience, silica in drainpot condensate samples can be either slightly enriched or depleted with respect to Clwhereas the Cl/Na ratio remains similar to the separated water. The most likely explanation for the former it that it is due to contamination by volcanic glass (pumice) rock fragments in the carryover, which are highly soluble and dissolve rapidly in hot water (Bruce Mountain, Pers. Comm. 31/5/15). The reduction in silica appears to be correlated with significant silica deposition in the steam tubes of the particular separators.

3.4 Wet Steam Damage

At some installations, the steam is so wet that it does not go into superheat through the nozzles. The mineralised water can then accumulate in regions where heat will vaporize it, or the water will migrate through the turbine until it goes out through turbine drains. Which occurs is generally dependent on both the degree of wetness and the turbine design.

The wetness can be from carryover, excessive pipeline scrubbing without proper drainage, or from steam scrubbers without proper demisting. Unreported tests undertaken by the authors and results from other plant operators indicate steam demisting is rarely as efficient as claimed. If the bulk fluid flow is more than about 1.5% wet, then the stagnant flow steam doesn't go into superheat in the nozzles. With wet steam, the energy extracted out of it by the first stage turbine blades drops the fluid well below the Wilson Zone. Most of the moisture gets entrained in the wet steam as slow moving droplets, but some of this water then accumulates in the relatively dead flow zones like the diaphragm walls, blade roots and interstage seals.

Water accumulating in the interstage area is very damaging because it will be blown though the narrow annular gap by the steam pressure. Water will erode metal from the rotor and damage the seals. As the clearances increase, the damage rapidly escalates. Rotors damaged in the interstages are both expensive and time-consuming to repair, as welding then heat treatment needs to be done before the re-machining. The alternative is making undersize seals.

Fig 7: Deposition in the turbine nozzles and casing. This is because the mineralised fluid coming through the nozzle is about saturation. The water flows into the cavity upstream of the first stage rotor blades. Here it is heated by heat flow through the steel from the higher pressure steam. The water evaporates, leaving the minerals behind.

If the diaphragm walls are heated by the incoming higher pressure steam, then the water can be evaporated off. The minerals left behind will accumulate as a deposit that reduces clearances as in Fig. 7. Eventually the gap will be closed up so that the deposition will act as grinding paste on the rotating components and metal will be very quickly removed. The rotor drum upstream of the first blade roots on some reaction turbines is especially prone to this effect. (Morris, 2015)

Steam that is near the saturation line after the nozzles will cause some deposition will occur. This will be silica rich because the soluble chlorides wash out. It leaves distinctive deposition with prominent wash lines (Fig. 8).

The scale can also form in the turbine rotor glands. Here the low pressure steam is superheated as it expands across the labyrinths that make up the gland. The silica deposits become a very effective grinding paste. As the rotor is abraded away, the clearances increase, so more steam (and potential deposition) is needed to maintain the gland pressure.

Wet steam also lowers the performance of the machine. Exact numbers depend on pressures, but steam that is 1% wet will be over 2% slower velocity at the nozzle outlet from the lower expansion ratio. This reduces the efficiency of the first stage blades as the steam will enter at less than optimum angle for the blade speed.

3.5 The Consequences and Rate of Scaling

The industry standard 50-60MW steam turbines have a steam flow of about 400t/h. If this is supplied from separators of 99.9% efficiency, the carryover is 400kg/h. With a brine of 2000mg/kg total dissolved solids, this is 800g/h of minerals. Allowing for 99% removal by pipeline condensation, scrubbing and demisters, it would mean 8g/h would reach the turbines. Even at this low rate, it can be a significant issue

Fig 8: Effect of wet steam - minor deposition on the vanes, mainly silica, and clear areas from water flow at the port walls. There has been post shutdown redissolving of solids so corrosion has started.

Toshiba (Pers. Comm. 2014) has stated that a deposition layer 0.1mm thick in the nozzles can have an effect on performance. This is from the increase in surface roughness and turbulence rather than reduction in cross-section area. From an operational viewpoint, the deposition would generally be about 1mm thick before the performance deterioration was noted. If this skin of minerals only was on the rear section of the nozzle vanes' trailing face, then it would weigh 500-650g. It would cause a reduction in port cross-section area of about 3%. As there is critical flow through the nozzles of an impulse turbine, the mass flow rate would drop proportionally and would cause a 1-2MW loss if there were no compensating measures to bring the flow rate back up. The higher the inlet pressure, the smaller the port area, so the clogging effect of scaling would be faster on high pressure machines.

Even at full load, many turbines operate on partially closed governing valves. This means the valves could be opened more to compensate as the deposition starts. Once they are fully open, the separation pressure could then be raised to bring the steam flow up. However, these are not solutions, only delaying the inevitable. Initial deposition rates would be slow, especially if the nozzle vanes were polished. However, once it had started to form, the turbulence and rough surface would allow the rate to accelerate.

The deposition rate, even on the 8g/h solids in the steam flow rate, can be quite rapid. If just 1% of the available minerals deposited on the vanes, then it would take less than a year to give the 1mm skin. In many machines, like the one shown in Fig. 4, the clogging is much faster than this. Though rapid, it isn't extraordinary. Output declines of 5-10% per month are not uncommon.

Deposition isn't always obvious because an outage of the machine, especially if the steam isolators don't seal, can redissolve the deposition from the condensing steam. Even if it isn't completely dissolved, the removal of the soluble minerals can weaken the integrity of the remaining deposit. That means much is thrown off when the machine restarts. Alternatively, changes in the steamfield can bring wet steam into the turbine and the process described above occurs. This is why there can be sawteeth in the generation data of a turbine that has scaling issues.

4. POSSIBLE SOLUTIONS

4.1Turbine Washing

For turbines prone to deposition in the nozzles, washing can be done. This can either be continuous or on an as needed basis. The latter is the better method, though it has to be seen as a palliative solution. The principle of the process is simple, with enough water being added to the steam to de-superheat it through the nozzles. This is generally about 2% of the steam flow. The excess water dissolves the deposition, so it either washes or disintegrates off. It is a process that does work, but there can be significant problems (Morris and Bacon, 2001)

The water supply (about 4% of total steam flow) has to be deoxygenated and free of minerals. The spray method has to be robust so mechanical components don't break off from the turbulence induced vibration. The steam path components will be damaged by the excessive water going through, so the shortened life needs to be balanced against the increased generation. If the wash water is oxygenated, then steel will be corroded from the vessels and pipeline walls and iron oxides/ sulphides deposited throughout the turbine.

Having said that, the effect of washing on the turbine's output can be dramatic. Fig. 9 shows a 10% increase in the performance of the Wairakei G4 within 5 minutes of washing started. The change was actually greater than shown as the governing valves had to be closed in just after washing started to prevent the machine overloading.

4.2 Drainpots

The most effective way of steam scrubbing still seems to be slow velocities in steam lines with the deep, baffled, large diameter pots. Lee (1982) set the parameters for good design. The older stations that followed these good design practices seem to be the ones that have had less turbine scaling issues.

4.3 Separator Redesign

The problem of turbine scaling is caused by carryover from the separators. The inlet spiral is a critical design feature for efficiency so there is the potential for retrofitting this on older plant. If the mass flows and steam velocities were reduced, then the carryover quantity would drop. The slower velocity would also allow more effective steam pipeline scrubbing. Having separators further from station and with more pot drains would also help the scrubbing. This is an expensive option, but the most effective one.

5. STEAM CONDITION STANDARD

Manufacturers of geothermal steam turbines define acceptable limits for the steam supply. These are usually in two parts, the quality and the purity. The steam dryness is usually set at or just below the saturation line. The purity is often defined in terms of various mineral constituents in ppm (mg/kg). If the steam is dry, then steam sampling by isokinetic probes is the sensible monitoring option.

However, if water is present, the mineralization is in the water which is unlikely to be homogenously dispersed, so steam sampling is not appropriate to determine the mineral loading to the turbine. That is why most turbines that have scaling problems pass their steam purity tests. When one works through the thermodynamics of the power stations' design, it is almost impossible to have dry steam at the turbine inlet unless there is a significant pressure drop in the steam lines or turbine control valves.

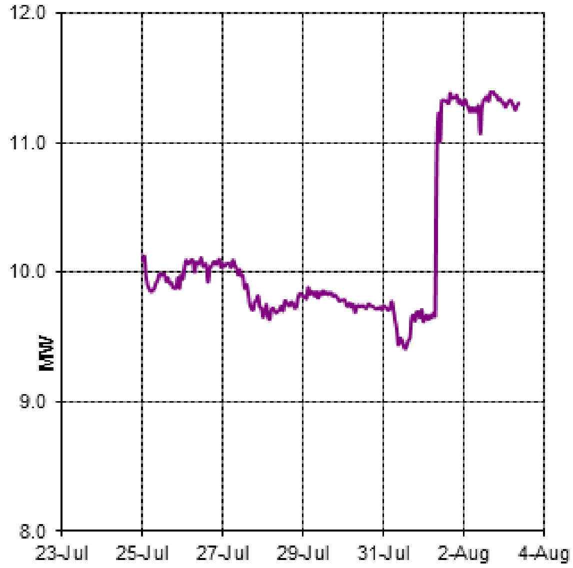

Fig 9: Effect of turbine washing on 11.4MW turbine

The authors propose that acceptable steam condition be defined in terms of maximum mineral loading in the water accompanying the steam, and steam wetness. To make the testing easier to do, the sample point would be the last pipeline drainpot before the steam enters the turbine. The discharge from the steam trap on this pot would be collected for analysis. To further simplify the testing, only sodium would be tested for. A multiplier based of the mineralisation ratio can be used to determine the total dissolved solids.

The acceptable sodium level in the steam trap discharge needs to be less than 0.1mg/kg. There is no theoretical basis to this number. It has been determined just by empirical measurements and observations that no scaling appears on the nozzles when the mineralization is at this level. For some geothermal fields that have different ratios of minerals in the water, then this acceptable concentration may need to change.

An essential part of the steam condition is the requirement that consistent superheat needs to occur in the nozzles. Measuring the steam quality is very difficult, especially on in-service plant. The critical determinant is the drainpot efficiency. As Lee (1982) showed, it can vary between 30 and 95%.

Rather than having complex measurements, the standard is defined simply in observational terms as superheat needs to occur in the nozzles with no evidence of vane washing. Generally evidence of water flow on the vanes is obvious, with bright or polished areas tracking across the vanes. These are most common near the vanes’ inner port walls. Other evidence is silica rich deposition occurring on the vanes (as all the salt is washed off by the water).

Wet steam lowers the turbine efficiency. This is because the lower dryness lowers the steam’s velocity. The pressure faces of the rotor blades then aren’t at an optimized angle. Because the steam flow measurements are relatively inaccurate, it is unlikely that the drop in performance can be measured. Operators can compensate for the drop by boosting the inlet pressure, which increases the mass flow rate, hence restoring the velocity through the turbine.

Because of the issues outlined above in the steam sampling methods, the authors believe that determining the turbine supply fluid quality and purity by steam sampling by iso-kinetic probes is not appropriate in wet steam lines. The flow regimes here are often much more complex than simply homogenously dispersed droplets with both stratified and annular liquid flow due to density differences between the steam and condensate.

What is proposed instead is using condensate flow analysis from the last drainpot steam trap discharge before the turbine. When combined with drainpot efficiency, it can be used to determine both steam quality and purity. From observational data, steam wetness of <0.5% and a TDS in the trap discharge of <0.3mg/kg appears to allow turbine operation without scaling and no accelerated water erosion on the turbine components. This low level of 0.3ppm TDS is comparable to the steam quality requirements defined for boiler plant in the IAPWS standard.

Therefore, those numbers are proposed as the acceptable steam condition requirement. For routine monitoring, the TDS would be a multiple of the sodium analysis results. Allowance would be made for drier steam having a higher acceptable TDS, as long as the total solid loading was unchanged, but the wetness should not exceed 1%.

6. CONCLUSIONS

If there is scaling taking place in the turbine, then it is almost certain that any solution will require significant steam supply equipment (station and/or steamfield) modifications.

The only way to guarantee that there will be no deposition, but also minimize erosion from over-wet steam, is to supply turbines with clean steam that is just below the saturation line.

The authors propose that the requirement for "steam" purity is that it should be less than 0.1mg/kg sodium in the condensate at the last drainpot before the steam enters into the power station building and the quality is high enough so that superheat occurs in the nozzles.

Isokinetic probes can give representative total flow conditions if there is no significant pipe wall flows of condensate. Geothermal pipelines should always be operating below the saturation line so don't meet this condition.

If there has been superheat in the steam between the separators and the station, then the above monitoring measures are unlikely to be effective. Flow limitations and steamfield modifications are the only ways to eliminate the evaporate dust.

7. ACKNOWLEDGEMENTS

The authors wish to thank Contact Energy for permission to publish this paper and acknowledge the support of the Geothermal Resources of New Zealand Research Programme funded by the Government of New Zealand. They also wish to thank their work colleagues who read the drafts and suggested changes to improve the document.

8. REFERENCES

Adiprana R, Izzuddin, Yuniarto E.: Gunung Salak Geothermal Power Plant Experience of Scaling/Deposit, Analysis, Root Cause and Prevention. *Proceedings World Geothermal Conference 2010.*

Brown K.L and Bacon L.G: Pilot plant experiments at Wairakei Power Station, *Geothermics 38, 2009*.

Dooley R.B. (plus 11 others): Turbine Steam, Chemistry and Corrosion – Experimental Turbine Tests, 1997, TR-108185, EPRI

Dooley R. B.: Steam, Chemistry and Corrosion in the Phase Transition Zone of Steam Turbines, Volume 1: Key Results, Summary and Interpretation, 1999, TR-108184, EPRI.

Giggenbach, W.F.: The application of mineral phase diagrams to geothermal corrosion. *New Zealand Geothermal Workshop, 215-236, 1979.*

Glover R. B.: Boron distribution between liquid and vapour in geothermal fluids. Proceedings 10th New Zealand Geothermal Workshop, 223-227, 1988

Jonas, O.: Effects of Steam Chemistry on Moisture Nucleation. *EPRI Workshop on Moisture Nucleation in Steam Turbines, 1995 Rochester New York, TR108942*

Kubiak J.A. and Perez J.: Developments in Geothermal Energy in Mexico – Part Twenty-Two. Causes of Erosion of the Rotor Blades in a Geothermal Turbine, *Heat Recovery Systems and CHP* Volume 9, No.2 159-168, 1989.

Lichti, K.A. and Bacon, L. Corrosion in Wairakei Steam Pipelines, *Proceedings New Zealand Geothermal Workshop, 1998.*

Lee K.C.: Performance Tests of the Condensate Drainpots at Wairakei, *Proceedings Pacific Geothermal Conference 1982.*

Morris C, and Bacon L. Turbine Washing to Remove Nozzle Deposition at Wairakei, *Proceedings NZ Geothermal Workshop, 2001.*

Morris C and Robinson A. Geothermal Turbines – A maintainer's perspective, Proceedings World Geothermal Conference 2015

New Zealand Geothermal Analytical Laboratory, http://www.gns.cri.nz/Home/Services/Laboratories-Facilities/New-Zealand-Geothermal-Analytical-Laboratory/Analytical-Methods, 2014

Parmono D. Scaling Investigation of Geothermal Steam Turbine Blades, Kamojang, *Report for Indonesia Power.*

Plyasunov A. Thermodynamics of Si(OH)$_4$ in the vapor phase of water:Henry's and vapor–liquid distribution constants, fugacity and cross virial coefficients. *Geochimica et Cosmochimica Acta 77 215–231 (2012)*

Richardson I, Addison S, Thompson G.: Steam Purity Considerations in Geothermal Power Generation, *Proceedings NZ Geothermal Workshop, 2013*

Thain I, Stacey R.E, Nicholson D.J.: Zero Solids Condensate Corrosion in Steam Pipelines at Wairakei, *GRC Proceedings,* Volume 5, 1981.

The International Association for the Properties of Water and Steam (IAPWS): Technical Guidance Document Steam Purity for Turbine Operation, 2013. Available: http://www.iapws.org/techguide/Purity.pdf [Accessed 29 May 2015].

Zarrouk S.J. & Purnanto M.H.: Geothermal Steam Water Separators: Design Overview, *Geothermics* , Vol. 53, 236-254, 2015.