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Geothermal Turbines – A Maintainer's Perspective

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ABSTRACT

The steam turbine is one of the most expensive capital items on geothermal power plants. It has very high ongoing operational maintenance costs, which can be directly linked to the plant availability and profitability. Many of the turbine's overhaul costs are solely a function of operation and cannot be avoided, though they can be mitigated.

From the authors' experience, it is those problems arising from the operation of steamfield system that can have a major influence on the turbine performance. These faults can have significant detrimental effects on the operating cost and life of the turbine and by extension, the geothermal station.

This work gives a brief overview on geothermal turbine design. It then looks into the primary sources of turbine damage that can arise from missing those established and well-documented concepts in steamfield design.

1. INTRODUCTION & BACKGROUND TO ISSUES

The steam turbine is one of the major capital purchases for any geothermal power station. Many types of financial models are used to evaluate and select what would be the most suitable power station plant, but the focus is almost exclusively on cost, configuration and return on capital invested. The analyses are invariably optimistic. Post operational reviews invariably show the modifications and maintenance costs were forecast to be significantly less than actual. The disadvantages of options, particularly those involving new technology are poorly identified. The same situation also occurs for the steamfield, with a minimised capital cost focus driving the design process.

A consequence of the focus on capital, rather than the technical issues, means inevitably the long term operation of the plant is compromised. This is both from lack of redundancy and designs at the edge of performance limits. Designs are often chosen that are beyond proven capability on the basis of construction cost savings. The authors haven't seen any development functional descriptions that have acknowledged the increased maintenance risks of the chosen design. The inevitable off-design running generally exacerbates issues. The hard lessons of the early developments haven't been absorbed by modern plant designers and operators, so that like Santayana's aphorism, "Those that do not remember the past are condemned to repeat it". If this seems a little harsh, look at how many new turbines have problems with scaling or deposition.

Pressure equipment like turbines and pipelines needs to have regular internal inspections, often dictated by regulations. They may start out yearly but once the plant has bedded in, can be extended to as long as five or six yearly intervals. These surveys then become the dominant maintenance cycle, with major work timed to coincide with the outages. The critical path of the survey is invariably the turbine overhaul. The turbine has to disassembled, repairs or replacements done to worn out or damaged parts, then everything recalibrated and reassembled. The programmed period allowed for this work can be as short as twenty days. The people doing the work often have only previous experience and their skills to guide the process as little condition information can be obtained while the plant is in service. In many cases, issues cannot be identified until after the machine has been opened up.

Most turbine problems are identified very early on in the life of the plant. There are very few issues that make their first appearance after the second full survey. Geothermal turbine design and material selection is generally based on thermal plant. If it is not sufficiently adapted to suit geothermal conditions, there is both erosive and corrosive wear on components. Manufacturers seem to be reluctant to change, which increases ongoing maintenance costs. These turbine design problems are generally relatively easy to address. Once these are sorted out, there are still significant time and cost over-runs during overhauls for the as-found work. The causes of these extensions invariably are from problems that can be related back to poor steamfield and/ or station design.

The four prime sources of turbine damage are: water, steam, deposition and foreign objects. These can cause erosion, corrosion and/ or cracking. The problem is deciding what is normal, is it tolerable damage or does it need repair/ replacement, and how to prevent or minimise further damage.

The overwhelming majority of damage done to the steam path components is by water. The problem is that the steam coming into a turbine is at or just below the saturation line and it gets wetter as it goes through the plant. This cannot be eliminated, only the effects mitigated.

The steam is moving through the turbine at high velocity and there are often significant pressure differences over relatively small distances. That means that if steam can bypass or find its way through the barrier such as tip seal or labyrinth, it has the potential to be erosive from the velocity imparted to it by expansion. Even without bypass, the steam velocity can be up to 500m/s which can be damaging in itself.

Deposition should not occur, but will happen if the steam is not clean. Almost all of it is from mineralised water retained in the steam.

Foreign object damage can occur, but is obvious and the cause of it usually apparent.

To understand the reasons for the damage and where it occurs, one has to understand the conditions in which these turbines operate. This is a subject that is not well covered, even at the basic level.

2. STEAM TURBINE THEORY

Geothermal steam turbines are open cycle, utilising the expansion part of a Rankine heat engine cycle. Turbines convert the energy of steam into work by a series of alternating sets of ports (also called nozzles or vanes) fixed to a casing, and blades (or buckets), attached to a rotor. There is a pressure drop across the stationary ports, which increases the steam velocity due to the increase in specific volume. The rotating blades extract work by slowing the steam velocity before it goes into the next set of stationary ports. (Figure 1 and Figure 2) This work is a drop in enthalpy. The combination of the stationary ports and rotating blades is called a stage, of which there may be five to ten in a typical turbine. For some designs, there may also be a pressure drop across the rotor blading (reaction blading), but the general principle is the same. In an idealised turbine stage, the process is isentropic.

Figure 1: Turbine with top casing removed. Steam inlet is on left with condenser on the right. This is just half of a double ended rotor. The fixed blading vanes direct the steam in the opposite direction to the rotor blades. The slot for the interstage drain can also be seen just behind the second to last set of rotor blades. The components oxidize rapidly on exposure to air.

Within the generalised principles, there are significant constraints on the turbine design. It is usual to limit the maximum steam velocity to below 550m/s, the speed of sound in steam. This is to reduce the risk of vibration induced damage and pressure loss from the sonic shockwaves. The power extracted by the rotating blades is maximised when the blade speed is about half the steam speed. These velocity limits restrict the pressure differential across a stage of blading, defining the minimum number of stages the turbine can have without compromising efficiency. In almost all stages, choking flow occurs in the expansion path, so the mass flowrate is only dependent on the upstream pressure. The tip speed of the last stage blading is also limited by the strength of the steel, which is relatively low because of the risk of Sulphide Stress Corrosion cracking. The tip speed defines the annular area of this stage, which together with the exhaust pressure, sets the mass flow through the turbine. The book "Turbine Steam Path Engineering for Operations and Maintenance Staff" by Sanders covers the design issues more comprehensively than the summary above.

Common practice is to have drains through the casing after each stage. These interstage drains allow water that is flung off the spinning blades to be taken out of the fluid stream. The blading and diaphragms may have extra design features like radial grooves or outer port wall notches to enhance the water removal. The drains usually have an orifice or steam trap to limit steam losses, though in the latter blade stages, they can just be holes in the casing that go straight through to the condenser.

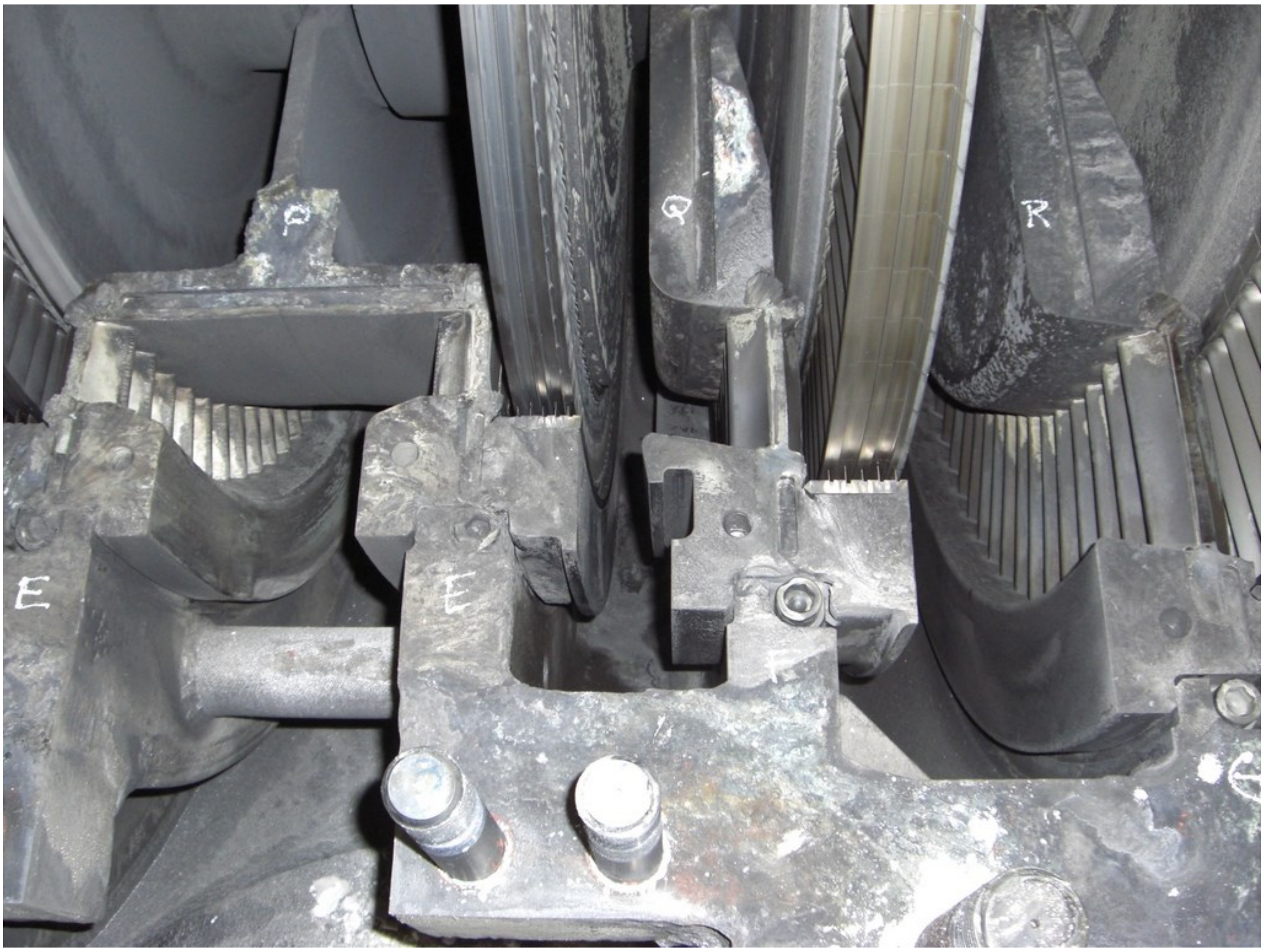

Figure 2: Turbine detail. The steam enters the cavity on the left and passes through the sets of stationary and rotating blades. The thin sealing strips on the trailing rings of the diaphragm stationary blades are to minimise the steam bypassing the rotor blades. The cavities between the diaphragms have drainage to allow water to be removed.

Normal practice to indicate steam conditions is to show a turbine's expansion line (TEL) as the red line on a Mollier diagram. (Figure 3) This is misleading as it only shows initial and final conditions of the bulk fluid, with a straight line between. In some cases, the diagram can be modified to show the conditions at the end of each stage, which will curve the line. Considering how the conditions vary across each set of blades yields a diagram like the green sawteeth in Figure 3. From this, it can be seen that the steam is dried out in the constant enthalpy (also called adiabatic or isenthalpic) expansion across the stationary blades of each stage. Note that the first stage goes into superheat. The rotating blades then extract work, utilising the momentum of the steam's velocity. This increases the steam wetness. The critical feature to note is the region of about 3% wetness. This is called the Wilson line or zone. When steam conditions drop through this line, there is spontaneous condensation of water droplets within the steam flow. Above the line, it is steam that is considered as the principal factor for damage possibilities; below the line, water is the dominant feature (Figure 4).

This green line sawteeth is not a "true" representation as it only shows the conditions of the bulk or total mass flow. The interstage drainage extracts water. Drying of the remaining fluid has the effect of displacing the sawtooth steps up to the right, as shown by the brown line in Figure 3. The apparent increase in enthalpy extraction shown in the graph is counteracted by the reduced mass flow rate. If the drainage is efficient enough and most of the water removed, or top up steam added from a secondary flash, then superheat can occur even in the latter stages of the stationary vanes. On some units, the extracted fluid is passed into lower pressure stages where partial flashing occurs before it is discharged. This gives a slight increase in steam flow to the later stages.

Once the steam conditions within each part of a turbine are understood, then the potential causes for problems can be identified. If one goes back to Figure 3, it can be seen that improving the efficiency of a turbine (steepening and lengthening the TEL) means that the exit steam gets wetter, so increasing the potential for more water damage. Poor interstage drainage will also have the same effect.

The analysis extends to off-design operation. For example, if the machine is part loaded by partially closed throttles, then the TEL is displaced to the right on the Mollier diagram and the steam enters the turbine in superheat. With excessive water in the inlet steam, the TEL moves down and to the left, so there is no superheat in the first stage ports. This is why turbine washing can remove deposition.

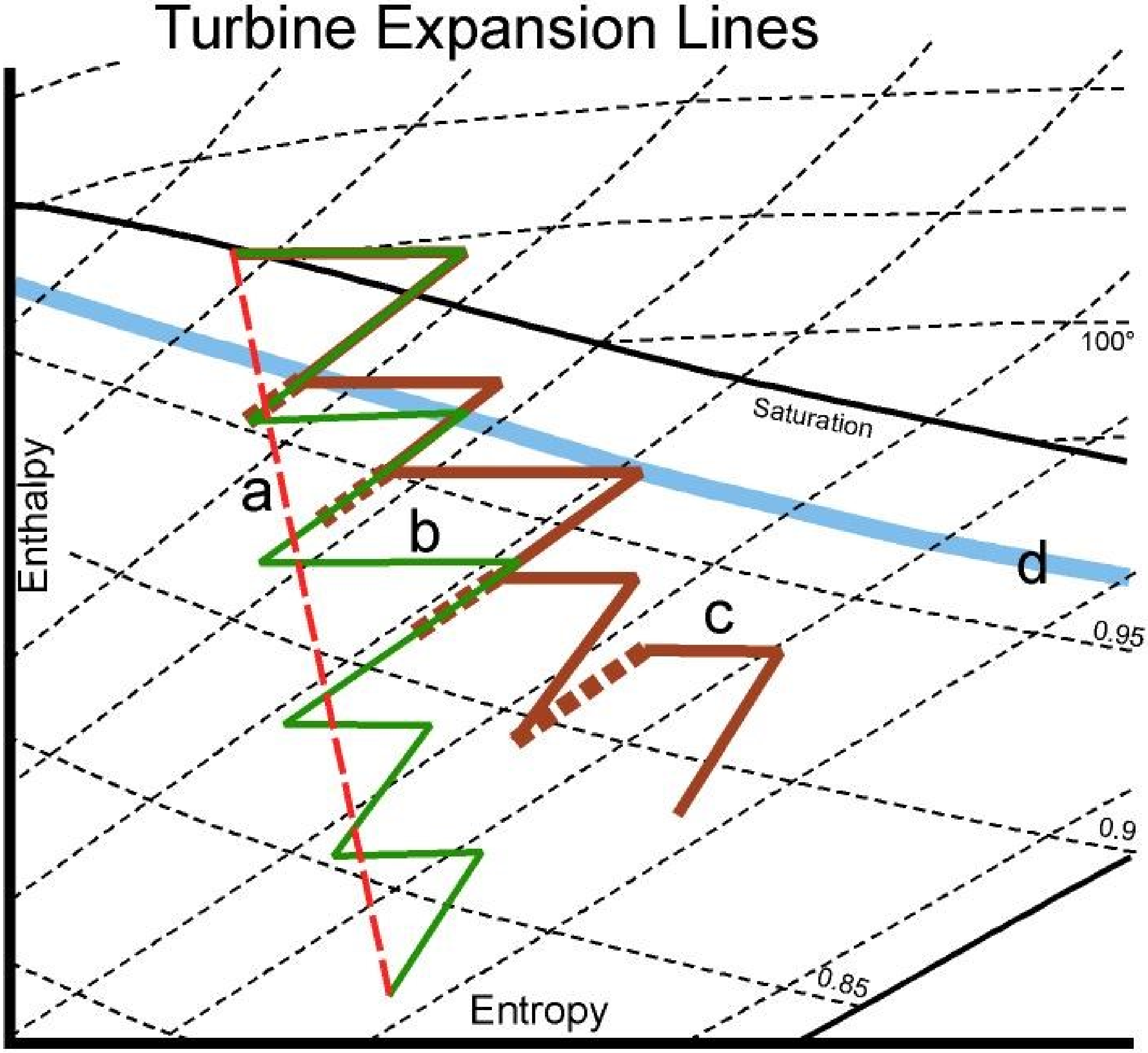

Figure 3: Turbine Expansion Lines (TEL) for a typical turbine. The red line (a), is the classic representation just showing the start and finish points. The green line (b) is what happens in each stage to the bulk fluid. The last two stages show the effect of reaction rather than standard blading. The work done in each stage is the same. The actual fluid properties through the turbine are close to what is shown by the brown line (c). The dotted section is the effect of the interstage drainage drying out the steam. The blue line (d) at about 3% wet is the Wilson Zone

The thermodynamics also determines the sites of the problems. Figure 4 is a modified graph from Jonas, using the Mollier diagram. This relates the damage mechanisms in turbines to their location. One of the issues to note is the concentrated salt solution that forms on the saturation line. This is very corrosive, particularly in regions of high stress. The acid below the Wilson zone comes from the first condensation of steam containing CO_2 and H_2S. There is no way of preventing it, only reducing its effect.

3. WATER DAMAGE

Water is the major source of turbine internal damage. Condensation of water is a necessary by-product of a geothermal turbine extracting power from the steam, so some damage must be expected. Effort is generally put into only trying to mitigate the extent of this damage as it can't be economically stopped. To make matters worse, the more efficient the turbine, not only are the clearances tighter so making them more susceptible to damage, but also more damaging water is formed within the steam path because more heat has been extracted. This combination of reduced clearances and more water means that on newer plant, damage is greater, so more extensive repairs are needed more often. Availability can suffer from the increased efficiency.

Entrained particles within the steam travel at a slower speed. The bigger the particle, the greater will be the speed difference. That means that slow moving water droplets in steam have a different relative velocity to the rotating blades. Blades will hit the slow moving water droplet on the convex sides of the blading, usually just back from the leading edge. This is why the erosion damage occurs there. There will always be damage to last stage blades in geothermal turbines, even under ideal conditions with stellite shields and good interstage drainage. Unfortunately; for most turbines, the conditions are less than ideal.

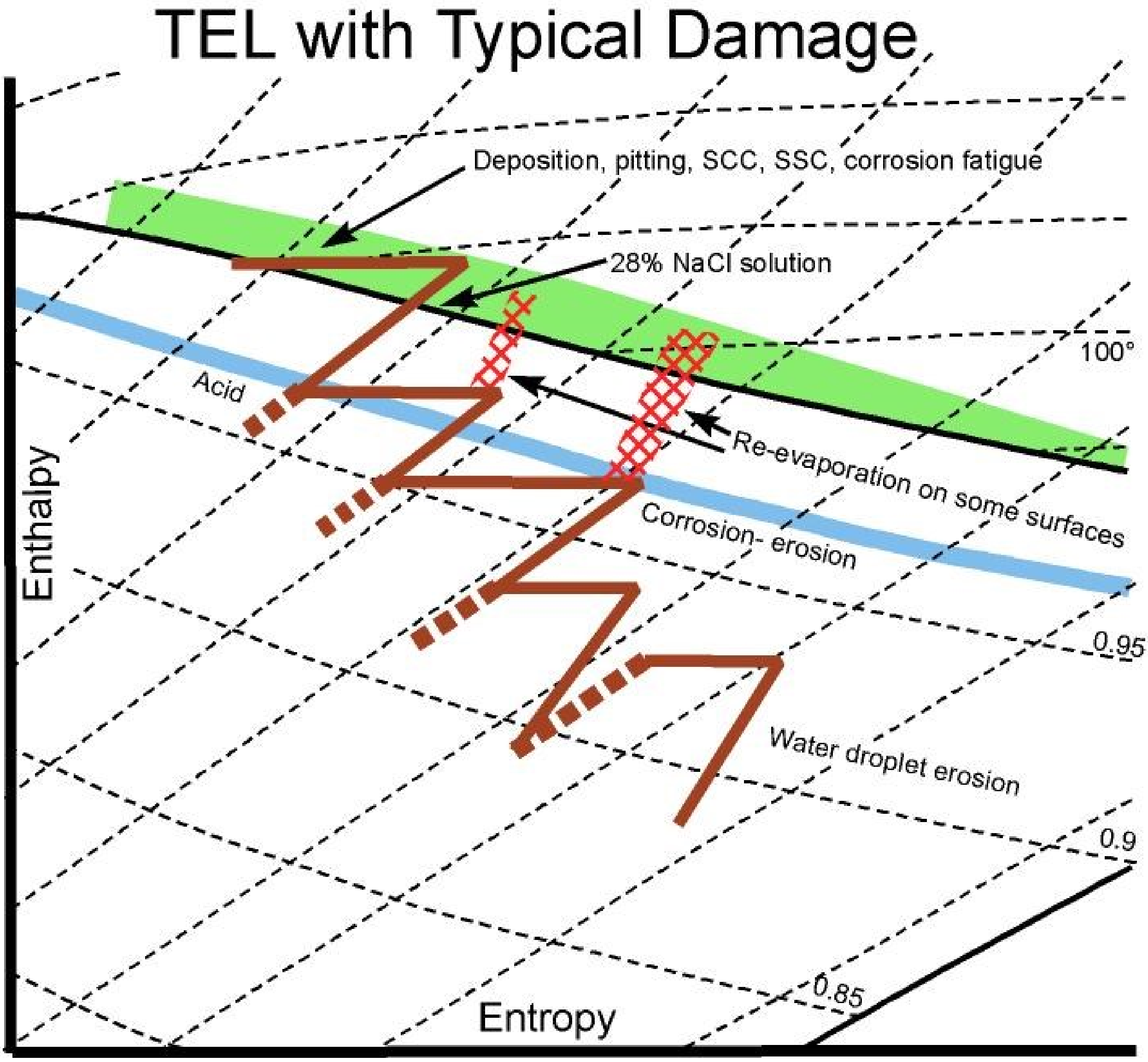

Figure 4: Turbine expansion line from Figure 3 showing where the various damage and problems occur. The red hatch lines indicate that because of heat flow and fluid dynamics, deposition can occur in some areas that are nominally wet.

In the ideal geothermal plant, the combination of separator carryover and pipeline scrubbing will mean that the steam gets to the station below the saturation line, but less than 1% wet. The condensate containing the scrubbed minerals will be near fully removed by traps. The chemistry of the condensate should be ~1ppm Silica. This is the design nominal turbine inlet steam conditions. If the condensate is too "pure", then corrosion in the pipelines is a real risk (Thain et al, 1981). Generally, the steam is about the right cleanliness and dryness when there is a slight deposition on the convex side of the first stage fixed blades.

It is unlikely that many plants nowadays genuinely meet these requirements for clean steam. The trend has been to go for well insulated, large diameter steam lines from separators close to station. Some plants have demisters or steam scrubbers fitted to clean the steam, but these are not always effective. Zarrouk and Purnanto (2013, 2014) showed that separators' efficiency drops at high inlet velocities. They also note that the calculations rely on variables that have not been determined for modern designs, but extrapolated from earlier work. There has been no validation of the extension. In fact, some of the data indicates that breakdown velocities can decrease as the separator diameter increases or when the wells feeding the separators are high enthalpy.

Figure 5 Small drainpot common on many new steam pipelines. Proven as ineffective at removing pipeline condensate.

Figure 6: Rotor erosion from water trapped in the interstage area. There were originally thin stainless iron sealing strips in this region to prevent steam bypassing the fixed blading, of which only the remnants of two remain.

It is a logical extension that if the velocities in steam pipelines are a similar velocity to those of separators at breakdown point, then the condensate or separator carryover droplets are so fine that they do not settle out of the bulk steam. The droplets are likely to be in micron sized particles (mist) that is unaffected by gravity. This means that the relying on wall condensation and drainpots as scrubbers will be ineffective. Even if the condensate accumulates on pipe walls, Lee (1981) showed that for condensate drain pots to be effective, they need to be deep, large diameter and baffled. Very few modern pots (like that in Figure 5) seem to meet these requirements so even if condensate is present, it will not be removed by the traps' blowdown. Operators proclaim good steam sampling results but can't reconcile these to the deposition and wash damage in the turbine.

Turbines are designed to trap and remove water from the steam path throughout the process, but even the best of these are not totally effective in a condensing turbine. About 15% of the steam will have been converted to water by the time it exits the last stage. For a typical 50MW machine, there will be about 15l/s of condensate that has to pass through at least some of the blading. This is under ideal conditions. If the steam coming in is wet, then the condensate loading is significantly greater and could overload the drainage.

A practical example of this carryover in one plant in the authors' experience had an inlet steam velocity of about 45m/s. The thermodynamic traps on the steamlines rarely operated, and discharged clean condensate, yet there was significant deposition in the turbine nozzles and wash damage on the first stage blades, indicating wet steam was coming into the turbine. The interstage drains also ran near flooded. Calculations indicated that most of the trap condensate could be explained by heat loss on the unlagged drain pots.

Adiprana et al (2010) shows high separator carryover in the steam at Salak, even downstream of the scrubbers and demisters. This is a very common circumstance. Zarrouk and Purnanto (2014) showed that the large diameter of modern separators invariably means poor efficiency. The authors have access to unpublished information and personal observations showing that many plants have significant carryover that is damaging their turbines.

Some modern turbines have no interstage drainage in the first couple of stages. This is of little concern if the steam is dry. However, if there is water carryover in the inlet steam, then the carryover water and new condensation in the rotor blades can cause significant damage. The major problem area appears to be the inter-stage region of the first few stages where the water is entrained in the steam blowby of the sealing strips. This entrained water can cause extensive wasting of the rotor in a very short period. Figure 6 shows typical corrosion-erosion. The same wash problems affect the outer components of the rotor blading, though this can just be from insufficient drainage rather than excessive water in the steam. The port walls, particularly the outer one, of the stationary blading often have swirling wash damage as well. Once the wash starts, it soon creates a preferential channel along the concave vane surface that can in the worst cases allow the vane to move.. Figure 7 shows this wash damage. These problems are exacerbated by inadequate sizing and poor maintenance practices of the steam trapping system.

4. STEAM DAMAGE

Most of the damage normally associated with steam is actually from the water entrained in it, as described in the previous section. If the steam is clean, then there is usually only a generalised slow erosive wear. The main problem is where the sealing between areas at different pressures is not effective because of misalignment, distortion or excessive clearances. As well as the axial and half joint sealing faces on diaphragms and casings, this includes the interstage seals themselves. These seals are on the inner side of diaphragms and are the major barrier to interstage flow. The wet steam passing through any of these poorly sealed areas can rapidly cause cuts, wiredrawing or generalised erosion defects (Figure 8).

Figure 7 Water erosion damage on exhaust side of first stage nozzle inner port wall. This region is supposed to be superheated steam.

Figure 8: Steam damage across halfjoint sealing faces of the stationary blading sets. Steam flow right to left.

With the high velocities and good insulation in many steam pipelines, superheat can occur. The pressure drops associated with the system exacerbate this. That means that mineralised water droplets from separator breakdown will evaporate, leaving behind micron sized particles of salt and silica. These form a very effective abrasive. The area most prone to this damage are the inner and outer port walls, trailing edges, and rotor tip seals of the first few stages of stationary blading. This is where the steam velocity is highest and the debris hasn't been able to be scrubbed for removal in the interstage drains.

These mineral particles can also accumulate or deposit in areas that are at the boundary between wet and dry conditions. There they will form a corrosion cell, especially if the area is under high stress. The presence of these mineral particles is why pitting is often found under deposition.

5. DEPOSITION

Deposition occurs because the steam coming into the turbine contains either mineralised water droplets or evaporates. It is generally from the same conditions that cause the water damage, which is separator inefficiency and excessive velocity in steam pipelines. Once the mineral laden mist in the steam gets to the turbine, the conversion to superheat is where most material deposits. It primarily occurs on first stage nozzles but can also be on first stage blades or even the second stage ports.

The dynamics of the steam sets the actual locations of the deposits. The particles accumulate in the relative low velocity region on the convex side of the port vanes close to the inner port wall. Figure 9 shows a typical deposition in the first stage nozzles. Once deposition starts, then the increased turbulence and the bigger boundary layer allows more to accumulate. The pressure drop across the port increases, which generates more superheat, so more deposition. This means that the combination of increased pressure drop and reduced massflow through the restricted ports can cause a rapid deterioration in the machine's output. The deposition can also occur in regions that thermodynamics indicate should be wet. This is because local circulation and heat flow from hotter components give drying conditions. One of the authors has even found high chloride deposition in the roots of the last stage blades – a region that should be very wet and not allow the highly soluble material to deposit.

The deposition on the vanes of the nozzles is often very high silica content. It is not a true representation of the fluid dynamics present but it is an indicator of the real cause of the risk. As Figure 4 shows, a concentrated NaCl solution can form on the nozzles at just above the saturation line. This brine will precipitate out if the concentration gets high enough or the fluid stays in superheat. The salt is the major cause of the pitting corrosion that is often found with or under deposition.

The deposition can be so significant that it reduces or even eliminates the clearance between the stationary and rotating parts. Then the silica acts as a very effective grinding compound. This can rapidly abrade components. Figure 10 shows a rotor groove from deposition in the glandbox. As the glands are often incorrectly trimmed, particularly when they are damaged, the combination of air, moisture and abrasive material can cause rapid damage here.

A problem that is being seen nowadays is where the rotor upstream of the first stage blading has deep erosion (Figure 11). This is caused from the fluid exiting the first stage nozzles being just below saturation rather than in superheat. The heavy mineralized water flows on the inner port wall. It then accumulates in the annular cavity upsteam of the first stage blades. Heat flow through the diaphragm evaporates the water, leaving behind the silica (Figure 12). The rotor rubs against this very abrasive accumulation. Significant amounts of metal can be removed quite quickly. It can result in the rotor being derated because of blades having to be removed for lack of blade root support.

Figure 9: Scale deposition in turbine nozzles.

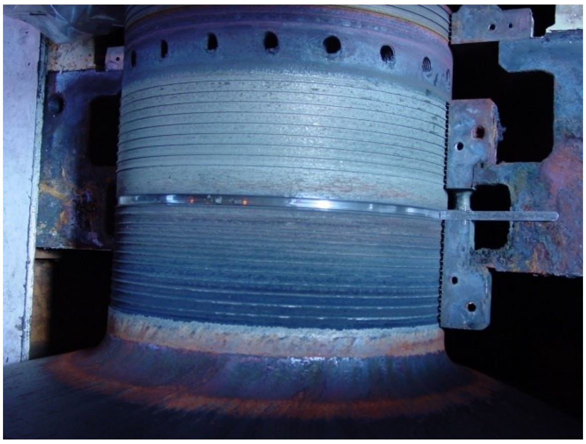

Figure 10: Rotor eroded from scale deposition in glandbox. 150mm ruler for scale.

Turbine washing or desuperheating can reduce or even eliminate the deposition and subsequent generation loss. Morris and Bacon (1981) describe one such installation and system. However, washing is a palliative operation, not a solution. The major undesirable consequence of the scrubbing water is to increase water damage, often as abrasive slurry, so operators can be exchanging one problem for another. The washing debris can cause abrasive erosion damage, particularly on exposed components like the tenon tips of the rotating blades (Figure 13). Because as discussed above, a concentrated brine solution can form, there has to be enough wash water present to guarantee the steam is well below the saturation line. Otherwise, the rotor erosion problem previously described will occur. There also has to be suitably sized interstage drainage on the first and second stage. To make washing worse, some stations use wash water that has not been deoxygenated, so aggravated corrosion will be added to the damage mix.

The steam conditions in turbines can vary, especially in those that are supplied by high enthalpy cycling wells. This means that the steam in the nozzles can vary between superheated and undersaturated if the cycle is large enough. A similar situation happens if the generation is load following. When this cycling occurs, the deposition that does form will be washed out and leave no obvious performance reduction. It can manifest itself as wash lines deposition on the vanes and blading.

Figure 11: Rotor abrasion caused by deposition from mineralized water flow through the first stage nozzles.

Figure 12: Rotor damage in figure GG caused by deposition on the annular cavity like that shown here. The steam is generally so wet that there is little if any deposition in the nozzles. The rotor damage root cause is poor separation coupled with excessive wash water flow and ineffective demisters.

The only real solution is having a clean steam supply. This means improving steamfield separation efficiency and scrubbing as discussed earlier. The design needs adequately sized piping to reduce steam velocities and allow pipeline scrubbing. For in-service plant, many operators don't consider this a viable option because of the cost. However, the capital savings from not addressing the problem are inevitably swamped by the increased downtime, maintenance costs, loss of generation and reduced life of plant. It is the "pennywise, pound foolish" philosophy writ large.

The pitting on the rotor blades from corrosion under the deposition can be the initiation sites for high cycle fatigue cracks. However, the blade failures are generally in the later stages while the pitting is at its worst in the first couple of rows. The blading that fails is either under unusual stresses or there has been design failing. This is typically the fundamental or root cause, with the pitting being a secondary issue.

6. FOREIGN OBJECTS

This is usually thought of as resulting from poor construction or maintenance practices and addressed by the commissioning steam blows. These aren't the only causes. They can be from high tensile components in steam path breaking. Despite their propensity to crack from stress corrosion, manufacturers putting cap screws in steam path components is just one example of the recurring failures that should have been designed out.

However, much of the damage is from the steamfield and “normal” operation. Dry steam wells feeding directly into steam lines can bring formation into the turbines. Figure14 shows a turbine’s steam strainer with the debris in while Figure 15 shows the debris. Most of it is rock but there are also rust flakes. The nearest well is over two kilometres away and there are several major elevation rises in the pipelines that the steam passed through. Steam velocity in the line was about 50m/s. This steam had also passed through a Z plate demister where the velocities would have been halved.

The rocks in the picture are only those big enough to be caught by the strainers. Smaller ones would have passed right through the mesh and into the turbine. These rocks can cause impact damage on the convex face of rotating blades. This may be seen as a mottled or peened appearance, but it is usually masked by the accelerated wear. The shock of the initial impact normally causes the rock to shatter into dust sized particles. These are abrasive and can damage the components, particularly the thin trailing edges of the diaphragm vanes like shown in Figure 16.

Figure 13: Blade tenon leading edge erosion from silt laden condensate. The rotor turns left to right. Wash lines of deposition can be seen on the upstream blading.

Figure 14: Rocks jammed in a steam strainer. This was downstream of a demister.

Figure 15: Rocks and debris retrieved from strainer in Figure 14. Note the ruler is in inches.

Figure 16: Erosion of trailing edge of diaphragm vanes caused by debris in steam. The rear edge should be straight

Towards the latter stages of a turbine, the debris can become entrained in the water. This becomes erosive slurry. It then can do significant damage to the fittings that minimise the clearances between the moving and stationary components. Many of these fittings are made of erosion resistant materials that are difficult to repair. Replacement of them can be complicated and time consuming, but is often the only option.

Deposition can occur in the steam pipework. Particles can break off the embedded mass of these deposits through thermal shock. These are then re-entrained in the steam and have the same effect as the rocks. They can actually be worse because the high chloride concentrations cause corrosion.

7. CONCLUSIONS

For effective reliable operation, geothermal turbines need clean dry steam from the steamfield or separators. Experience from machine overhauls at many plants shows it is not being provided. These steam supply design faults on geothermal stations are causing large operational costs in increased maintenance, loss of generation and reduced availability. These are different from, but related to turbine design and material problems. Many of the faults can be traced back to lowest capital costs decisions and pushing the design envelope into unproven operating performance territory during development. The steam problems can be engineered out. This would be a lot cheaper if done during design stages, rather than retrofitting on an operational plant. The most expensive option, though it the one most often adopted, is to do nothing but continue to repair the damage.

One of the most depressing things about the issues raised in this paper is that none of them are new. The causes and solutions have been known across the geothermal industry since long before most plants were designed. It is not openly discussed because there has been reluctance by many operators to acknowledge faults and the consequent production losses for commercial sensitivity and liability issues.

However, even with that silence, there have been numerous papers published over the years identifying problems and the solutions. Bracaloni et al wrote about the problems in Italy from dirty steam. Kubiak & Perez detailed the erosion from insufficient drainage for a specific turbine in Mexico over 25 years ago. Adipana (2010) looked at scaling. Richardson et al (2013) detailed the problems on some New Zealand plants. Unfortunately, these are just a few papers from a very long list.

The faults and their remedies have been long known. It is the developers and steamfield designers that have failed to act.

8. ACKNOWLEDGEMENTS

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