GRC Transactions, Vol. 41, 2017

Steam Turbine Rotor Life Management

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Keywords:

Failure mechanisms, FEA Modelling, SSC, fatigue , vibration

ABSTRACT

Undertaking independent steam rotor and blade life management enables owners and operators to control the inspection and maintenance activities likely to be required over the design life of the asset, and to quantify the life beyond that estimated by the original equipment manufacturer. In geothermal power generating plant, the geothermal steam turbine and generator form the most expensive components, with the longest lead times for replacement. To undertake the life management process accurately the engineer needs to know the operating conditions, material properties, degradation mechanisms and dimensions of the various components forming the steam path.

This paper looks at the operating conditions generated by geothermal steam, degradation mechanisms encountered during component service, required/specified mechanical properties ideal for the operating conditions, and the steps required to build an engineering model which will enable a rotor life management plan to be generated.

1. Introduction

Currently twenty-four countries have geothermal assets generating electricity. Including plant under construction, the global capacity will exceed 13.4 GW by close of 2017 [1]. This is approximately half the estimated global geothermal capacity. The geothermal steam utilised is dependent on the location. as shown in Table 1. As this shows, the operating conditions can vary significantly from steam field to steam field.

In several power markets the move to renewables (photo-voltaic and wind) has significantly affected the base load power market. This in turn has adversely affected conventional thermal power generation and also geothermal power generation. Geothermal power offers the power market one reliable renewable baseload option; the other being Hydro.

Knowledge of the particular degradation mechanisms affecting the unit, and having a life management plan can enable the plant manager to schedule longer campaigns based on sound engineering assessment with resultant higher availability and production.

2. Environmental degradation mechanisms

2.1 Sulfide Stress Cracking (SSC)

The operating environment in the steam used in geothermal power generation contains significant levels of H_2S and other acidic phases such as CO_2 and on occasion boric acid gas and HCl acid gas. The presence of H_2S is of concern as brittle SSC failures may occur. It has been found that SSC requires three conditions to be met for cracking to occur. These are the environment, stress level and high mechanical properties (tensile strength and hardness). It is possible to reduce the likelihood of SSC if the requirements of ANSI/NACE MR 175/ISO 15156-1/2/3(2009) [2] are applied. The cracking behavior of low alloy and martensitic stainless steels commonly used as rotor material when exposed to H_2S is controlled by the complex interaction of several parameters, including the following:

- Chemical composition, tensile strength, heat treatment, microstructure and surface finish.
- Partial pressure of H_2S or equivalent dissolved concentration in the water phase.
- Acidity of the water phase (pH).
- Chloride or halide ion concentration.
- Level of oxygen (normally low but if present can give synergistic Chloride Stress Corrosion Cracking).
- Exposure temperature.
- Pitting resistance of the material in the service environment.
- Galvanic effects.
- Applied stresses.
- Exposure time.

The three main factors are:

1) Partial pressure of H_2S. If this is less than 0.3 kPa (0.5 psi) it is considered unlikely that SSC will occur in normal materials used in rotor steels and blades. It must be noted that high strength alloys with yield strengths above 965 MPa can crack at this partial pressure.
2) Material Condition. Material properties and heat treatment of the material should be such that the material exhibits a hardness of less than 22 HRC. It has been found that materials with hardness below this value are unlikely to suffer SSC.
3) Applied stresses. In most cases the rotors used in geothermal application are low stress items and hence SSC is unlikely. During operation the original applied stress can be increased by degradation mechanisms, such as localised corrosion, introducing stress concentration factors resulting in the increased risk of SSC.

By managing the three main factors the risk of SSC can be minimised.

2.2 Moisture Induced Damage

Most steam entering the high pressure section of a geothermal rotor will contain small amounts of water. The moisture portion of the mixture increases as the steam passes through the initial stages of the expansion and moisture content increases to the highest level at the low pressure section blading (approx. 12%), see Figure 1.

Table 1: Variation in steam, gas and impurity content at five geothermal resources [3]

Location		**Geyser U.S.A**		**Matsukawa Japan**		**Kakkado Japan**		**Cerro Prieto Mexico**		**TIWI Philippines**	
Steam Quality %	H_2O	98.05-99.51		99.40-99.80		99.85-99.97		99.08-99.78		98.43-99.16	
	Gas	0.49-1.95		0.20-0.60		0.03-0.15		0.22-0.92		0.83-1.67	
Gases Content Vol%	H_2S	1.69-2.99		12.9-17.7		9-26		20.9		0.8-2.57	
	CO_2	63.5-69.3		79.3-85.2		65-87		79.1		96.64-98.63	
	Bal	37.69-34.89		1.7-4.2		0.5-15		-		0.37-4.4	
		Condensate	Hot Water	Condensate	Hot Water	Condensate	Hot Water	Condensate	Hot Water	Condensate	Hot Water
Condensate and hot water (ppm)	pH	6.5	6.7-7.3	4.4-4.9	4.4-5.3	6.0-6.4	8.8-9.1		5.8-6.6	4.2-5.9	7.5
	K	-	-	0.3-3.0	120-300	0.1-0.28	55-67		631-2031	0.07-0.37	830
	Na	-	-	0.8-5.0	152-360	0.27-0.72	460-501		4406-7764	0.05-3.0	4400
	Mg	<1	-	<2.1	4.7-14.5	<0.1	0.01-0.02	-	-	0.02-0.20	0.19
	Ca	<1	-	<1.6	12.8-28.8	Trace	5.8-9.0	-	259-359	0.02-0.20	85.0
	Fe	<0.1	-	0.45-17.8	235-630	0.01-0.05	0.06-0.09	-	-	<0.31	0.31
	Al	-	-	<2.0	6.5-28.6	0.01-0.04	0.14-0.64	-	-	Tr-0.20	0.14
	Si	0.71	-	0.83-4.7	273-566	0.22-0.52	256-364	-	179-1458	0.02-1.72	345
	Cl	39	-	3.3-6.7	4.3-13.8	1.9-3.4	625-685	-	928-14934	0.91-173	8970
	SO_4	229	-	2.0-40	1188-1856	0.24-0.83	64-82	-	4.9-62	13.2-53.7	46.5
	CO_2	-	-	12.4-51	4.3-6.5	14.40	Trace	-	42-494	106-108	-
	H_2S	5-10	30-205	10-52.2	1.7-3.3	25-58	2.1-3.4	-	24-165	6.0-8.9	-

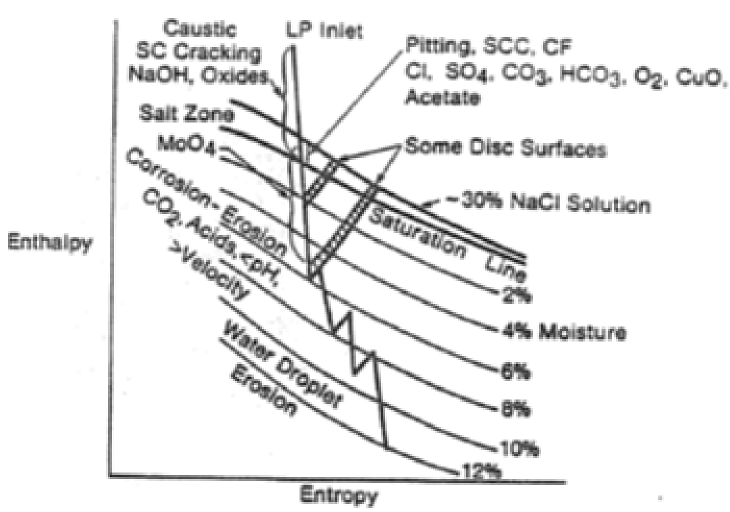

Figure 1 Mollier Diagram showing typical expansion line through steam turbine and associated damage mechanisms as function of expansion of LP steam. [4]

2.2.1 Impact Erosion

This is the most common form of water damage found on the steam path componentry. For impact erosion to occur, the moisture must be present in sufficient quantities for water droplets to form and collect. This normally occurs on stationary component surfaces in areas where the water formed cannot be drained. Once the water has collected at sufficient levels, droplets are then released from the solid surfaces and accelerate into the steam path causing impact damage for example to the leading edges of the following blades, see Figure 2 (a) and (b). Water removal is critical from the steam path in the latter stages where the steam flow enters a two phase state. In the later stages of the rotor, the blades normally have drainage grooves extending along the suction side of the leading edge, see Figure 2(b). The coverband does not extend over the leading edge area, allowing the water to be thrown into the water catcher belt designed into the rotor casing / diaphragm.

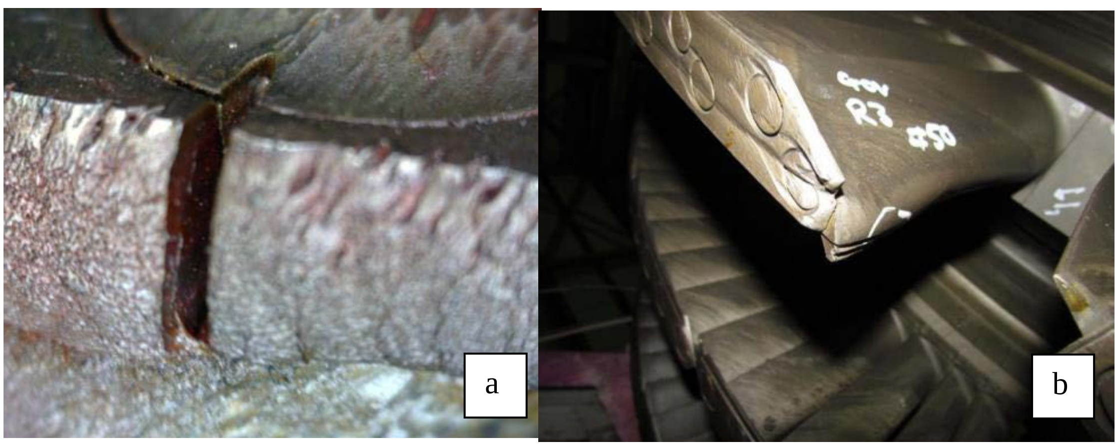

Figure 2: a) Water droplet erosion on leading edge of rotating blade sufficient to cause water jetting of coverband and b) the compromise of tenon integrity.

After prolonged operation, localized loss of material can remove the profile of the drainage grooves. Where this is likely to occur, the addition of an erosion shield (hard facing material inserts brazed into the leading edge on the suction side) should be considered. Erosion shields are normally specified for areas where the water content is such that drainage grooves would not cope with the loading. The erosion shield normally extends down the leading edge on the suction side to a position where the tangential velocity for the blade is insufficient to cause erosion, typically 240 to 250 m/s, see Figure 3.

2.2.2 Blade Trailing Edge Erosion

This is normally found on the last stage of blades and occurs on the discharge face of the lower half of the blade suction side. The damage is normally seen on the inner diameter a short distance from the root platform and set back from the trailing edge, see Figure 4(a). It is commonly associated with low load running.

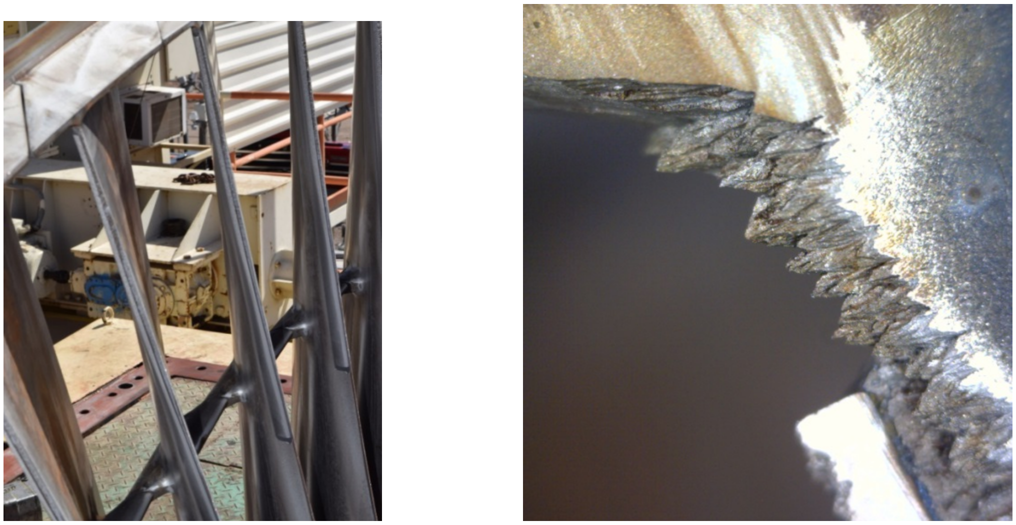

Figure 3. Typical appearance of erosion shield on last stage (LP-0) blades exposed to heavy erosion damage. Typical appearance of erosion damage shown on right.

2.3.3 Water Washing Erosion (Throttling)

This is a form of erosion which causes micro ruptures of the material surface as water flows over the metallic surfaces at high velocity. It can be seen on the rotor blade root fixings especially the crown of the disc fir tree if a gap is present, see Figure 4(b). It is also seen on coverband edges, tenon heads, and diaphragm inner and outer ring surfaces.

Figure 4: a) Trailing edge erosion and b) water wash erosion on rotor blade root fixing.

3. Operational Degradation Mechanisms

3.1 Foreign Object Damage / Domestic Object Damage

Damage is generated by debris within the steam flow impacting the stationary and rotating parts in the steam path. Material can be released from the steam path components (domestic) and/or be items left in the steam path following an overhaul (foreign). Foreign object damage can be seen on all stages of the rotor. The dents or craters formed can vary in size and the degree of damage generated depends on the size of the particle, its composition, and the section size, stiffness and relative velocity of the component impacted.

Figure 5: Damage from "domestic" object seen on leading edge of rotating blade.

If the material is associated with the failure of a component on the rotor, the section of the component released is likely to be large and may produce significant (domestic) damage to the impacted part, see Figure 5.

If the debris is large enough it will be trapped between the stationary vanes and rotating blades resulting in extensive damage to the rotating components. Material trapped at a seal can act like a machining tool, trepanning the rotating blades or the rotor. The release of components on the smaller blades and stationary components may not be detected by vibration sensors, allowing significant consequential damage to be generated before the unit is brought down.

This damage mechanism can be an initiator of consequential (domestic) damage in relation to other mechanisms occurring in the steam path. The damage can be described as follows:

- Peening type damage.
- Deformed diaphragm vane on leading and trailing edges.
- Large surface craters and tears.
- Massive craters and material rupture damage.
- Domestic debris trapped between stages.

3.2 Solid Particle Erosion (Abrasion), Scale Formation and Surface Deposits

Solid particles and scaling phenomenon are of major concern in geothermal power plants and control of the dissolved solids and solid particles in the steam entering the steam path and scale formation is paramount. They can affect old or new plant with rapid degradation generated to the seals, blades, diaphragms and the main rotor body. In geothermal plants the scale formed is primarily silica (dissolved or particulate quartz) together with traces of corrosion products from upstream pipelines or from the wells. In some cases the steam is water washed in the high pressure steam line by injecting water which scrubs the silica from the steam. In other cases the solids are separated by scrubbers located near the power station. The build-up of the deposits can be extensive and lead to abrasion wear on the main body of the rotor, diaphragms, gland seals (see Figure 6) and casing. This again can go undetected with the onset of damage being indicated by changes in pressure readings or inspection. Solid particle erosion will normally manifest itself on the outer regions of the stationary vanes. The rotating blades do not normally exhibit the same level of degradation to that seen on the stationary vanes, however; due to the rotational stresses present the effect of the damage on the integrity of the blades or coverbands can be significantly greater when compared to the stationary components.

Figure 6: a) Solid particle erosion found on gland seals. b) Scale (silica) formation

The particulate deposits can lead to blockage of drains which can adversely affect the gland seal areas. If material is lost from the trailing edges of stationary vanes, the steam discharge angle can be affected, changing the dynamics of the subsequent blade row together with a loss in efficiency.

3.3 Component Rubbing / Fretting (Corrosion and Fatigue)

Axial and radial clearances of the steam path components are strictly specified to increase the efficiency of the units and minimise steam leakage around the outer edges of the blading (coverbands). Rubs can occur as a result of high vibration on start-up, shut down, during an overspeed event or when events occur resulting in a significant unbalance. The rubs can be associated with historic events and may not lead to further degradation, see Figure 7. If the contact on the coverband is severe, it can result in damage to the tenon heads leading to the release of the coverband and eventually the blade aerofoil due to fatigue. If the thrust bearing is damaged, large axial movements can occur resulting in damage to more of the steam path components. Rubbing on the casing can occur and is normally associated with excessive overspeed, high vibration (radial movement) and when the casing is distorted.

Fretting induced erosion damage and material loss occurs without the presence of a corrosive species and is caused by the movement of two surfaces nominally in tight contact. Once the fretting has started it can develop into fretting fatigue.

Figure 7: Groove cut into coverband by diaphragm seal

Fretting can be seen when lacing wires are present on the later stages in the steam path, where the lacing wire passes through a drilled hole in the aerofoil section of the blade. It can also be seen on blade root load bearing surfaces and on the vertical side faces of blade shanks as they move between each other leading to areas of stiction and cracking. This mechanism can be the cause of significant damage as failure of the latter stages of blades will liberate larger debris into the steam path (domestic object damage).

3.4 Fatigue Failures

The rotor low alloy steels and martensitic blade and vane stainless steels will fatigue crack if subjected to cyclic stress above their fatigue limit (endurance limit) which for rotor steels is approximately 50% of the ultimate tensile strength (UTS) and for martensitic grade 410 stainless steel is approximately 65% of the UTS. Below these stress levels fatigue crack initiation and propagation should not been encountered. However, surface features can act as stress raisers increasing the applied stress to exceed the endurance limit. This is especially true of changes in section profile and when surface pitting and fretting has occurred. Once a crack has initiated the crack growth rate will follow the fatigue crack growth model (Paris' law) used in materials science and fracture mechanics. The basic formula is:

$$\frac{da}{dN} = C\Delta K^{m} \qquad (1)$$

Where *a, N, C, ΔK and m* are crack length, number of load cycles, material constant C, range of the stress intensity factor and material constant m, respectively.

Fatigue initiation and propagation are dependent on the presence of external forces or introduced features sufficient to initiate a defect of the critical size, which when subjected to cyclic loading, will grow. One of the most common operational factors which can adversely affect the blades is the blade damping. If the design of the rotor is such that a component is exposed to energy impulses (e.g. passing frequency) close to one of its natural frequencies, and no damping is present, then cracking will be induced.

When high cycle fatigue is the main damage mechanism the surface will exhibit a crystalline appearance with visible beach markings (arrest lines) indicating when the cyclic stress cyclic was stopped during operation, see Figure 8. Low cycle fatigue is designated as requiring less than 10,000 cycles to cause failure. It is most commonly found in conventional steam turbines and is associated with thermal gradient changes during start-up /shut down. It can be seen on geothermal turbines but due to the lower operating temperatures and the units being predominately base load the effect is reduced.

3.5 Vibration

The blades on the rotor are most susceptible to high cycle fatigue and are subjected to stresses caused by the vibratory stimulus developed within the steam path during service and installation issues. The vibration magnitude varies along the rotor and is affected by the frequency and magnitude of stresses present on each row of blades. The rotor can be considered as having high, intermediate and low pressure steam path excitation forces. These are associated with several vibrational stress sources specific to each pressure zone, see Table 2.

Figure 8: Typical locations and appearance of fatigue fractures.

Table 2: Steam path exciting forces, harmonic and typical sources.

Section of Rotor	Harmonic	Typical Vibrational Stress Sources
High Pressure (HP)	High per revolution (40x)	Nozzle tolerance limits
		Upstream wake degeneration
		Structural turbulence
Intermediate Pressure (IP)	Nozzle passing frequency (NPF)	Nozzle wakes
	2x NPF	Diaphragm harmonics
	3x NPF	Diaphragm harmonics
Low Pressure (LP)	One per revolution	Relative displacement nozzles to blade
	Two per revolution	Diaphragm joints
	Multiple/revolution	Structural supports in steam flow path
	Medium/revolution	Diaphragm harmonics Aeroelastic disturbances
	High/revolution	Nozzle turbulence harmonics Upstream wake degeneration Structural turbulence

Of all the vibrational effects listed in Table 2, the most common cause of damage is the effect of nozzle impulse which is generated by distortions in the steam / liquid flow which produces a pressure pulse on the rotating blade. If this pulse is close to the natural frequency of the blade then resonance will occur. It is important that when diaphragms are reworked the throat thickness of the vanes is maintained, in order to preserve the mismatch between pressure fluctuations and the blade frequency responses.

4. Rotor Fitness-for-Service and Remnant Life Assessment

Pivotal to the remnant life assessment is the development of a finite element model of the rotor. The subsequent finite element analysis needs to be able to simulate the situations in which damage occurs. For example thermal mechanical fatigue may only be accounted for accurately throughout the entire rotor by modelling transients such as start-up and shut down, whilst accounting for stress corrosion cracking would potentially require analysing the steady state full load scenario. Consequently many load cases / scenarios may need to be considered.

Furthermore, a comprehensive understanding of the current condition, past usage of the turbine in terms of number of hours of operation and number of starts is needed to enable accurate assessment of damage accrued to date.

4.1 Condition assessment

On rotors which have been in service the current condition needs to be assessed. This is done by a combination of the following:

- Visual Assessment.
- Metallurgical Evaluation.
- Hardness testing.
- Chemical analysis.
- Non-destructive testing.
- Rotor geometry / dimensioning including blades (if OEM data not available).

The operational data, any repairs undertaken since entry into service and steam chemistry will also be collected.

Once the information has been collated the generic rotor model can be generated. The finite element modelling will be specific to the installation conditions.

4.2 Finite Element Modelling

The first step in development of the finite element model is assessing the thermal properties of the steam boundary conditions that govern the rate of heating or cooling of the rotor on start up or shut down. Capturing this accurately governs how accurate the resulting thermal stresses are modelled.

Elaborate computational fluid dynamics (CFD) models can be used to develop the required heat transfer boundary conditions on the rotor by explicitly modelling the steam flow through the turbine. This approach comes at a price and such an approach is usually prohibitively expensive both in terms of computational expense and being commercially viable. More traditional approaches can be used, which utilise well known Nusselt correlations to model convection which is the dominant heat transfer mechanism for steam turbines. For rotors the correlations usually take the form as given in Table 3.

Table 3. Nusselt correlation equations used to model convection which is the dominant heat transfer mechanism for steam turbines.

$$h_{shaft} = 0.001 * C_{STM} * NU/DIA$$

$$C_{STM} = 9.46 + 0.2086 * p + 0.114 * T - 0.000235 * p * T$$

$$NU = 0.073 * RE^{0.7}$$

$$RE = 3.142 * 10^{12} * TURN * DIA^2 * p/\left(60 * (7.6 + 0.042 * T) * 232 * (h - 1942)\right)$$

$$T = Temp(p, h)$$

where

h_{shaft} is the surface heat transfer coefficient (in $Wm^{2}K^{-1}$),

T is the temperature (in °C),

p is the pressure of the steam (in bar),

h is the enthalpy of the steam (in J/kg),

DIA is the shaft diameter (in mm),

and TURN is the speed of the shaft (in rpm).

Steam temperatures and pressures can be deduced from operational data, thermodynamics and steam tables.

Once the thermal boundary conditions are known the thermal analysis can proceed resulting in calculated metal temperatures. These metal temperatures can then be mapped across to a thermal mechanical model, as thermal loading, which in turn leads to the calculation of thermal stresses. To calculate the total thermal-mechanical stress, mechanical loads need to be applied, namely centrifugal loading and blade / bucket loading.

On application of these loads the thermal-mechanical analysis may proceed, resulting in a thermal mechanical stress distribution, highlighting areas of high stress during start up, steady state and shut down.

The locations represent locations that may be susceptible to fatigue and or stress corrosion cracking or combined corrosion-fatigue. This can help reduce the scope of subsequent in-service inspections. Figure 9 shows locations of high stress, susceptible to fatigue in a steam turbine rotor to fatigue.

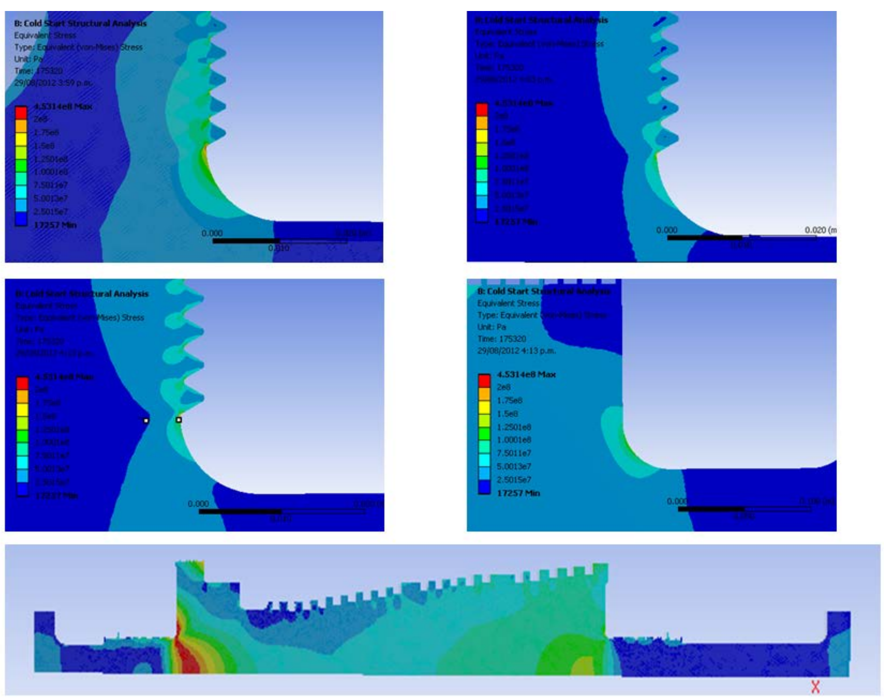

Figure 9: Stresses at critical locations on steam turbine rotor highlight areas for inspection.

4.3 Life Assessment

The process of life assessment is shown in Figure 10.

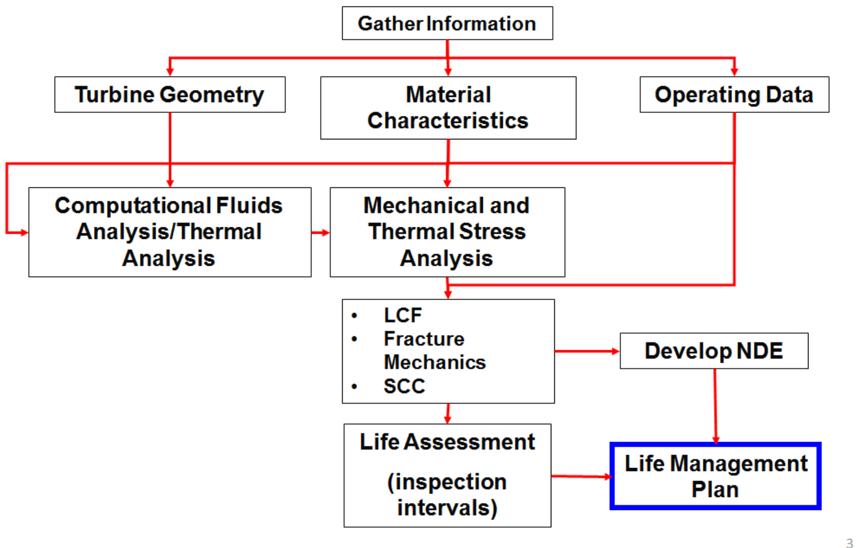

Figure 10: Life Assessment Process

Locations of high stress are highly susceptible to developing flaws. A specific assessment in the known defect locations can be undertaken if these areas do not coincide with location of high stress.

The critical flaw sizes can be determined using a Level 2 defect assessment in accordance with BS7910:2013 "Guide on methods for assessing the acceptability of flaws in metallic structures" [6]. These procedures consider failure from both plastic collapse and brittle fracture. Such an approach is highlighted in the Figure 11.

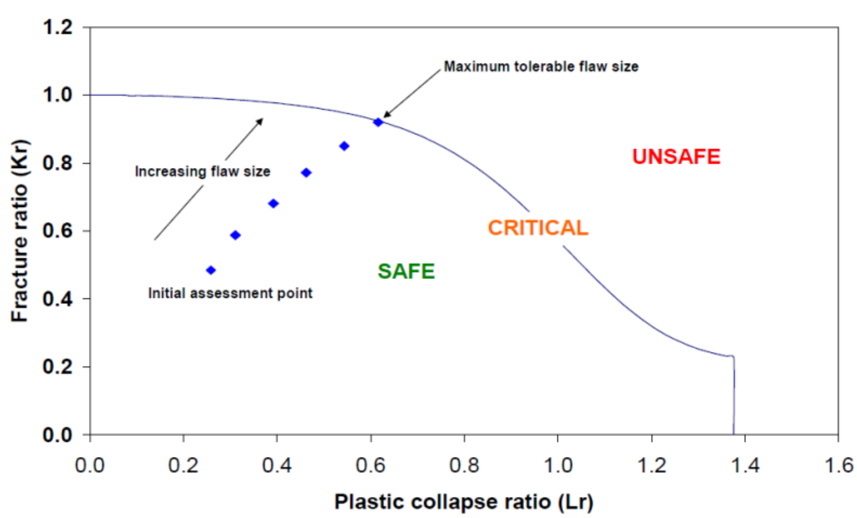

Figure 11: Critical flaw size approach from BS7910.

In terms of remnant life assessment there are two main damage mechanisms that are assessed; fatigue and SSC.

For fatigue, lifetimes to crack initiation can be determined using stress / strain vs cycles to failure curves, whilst lifetimes derived from crack propagation can be calculated using the Paris' law described in Equation 1 as given above.

Depending on the crack growth mechanism identified, a suitable crack growth law can be constructed. This may be based on SSC or fatigue crack growth. The crack growth lifetimes can then be used to determine suitable in-service inspection periods (campaigns).

A life management plan can be developed based on knowledge of the critical locations and lifetime at such locations. An example is given in the Figure 12 of how an inspection period may be derived for a given location.

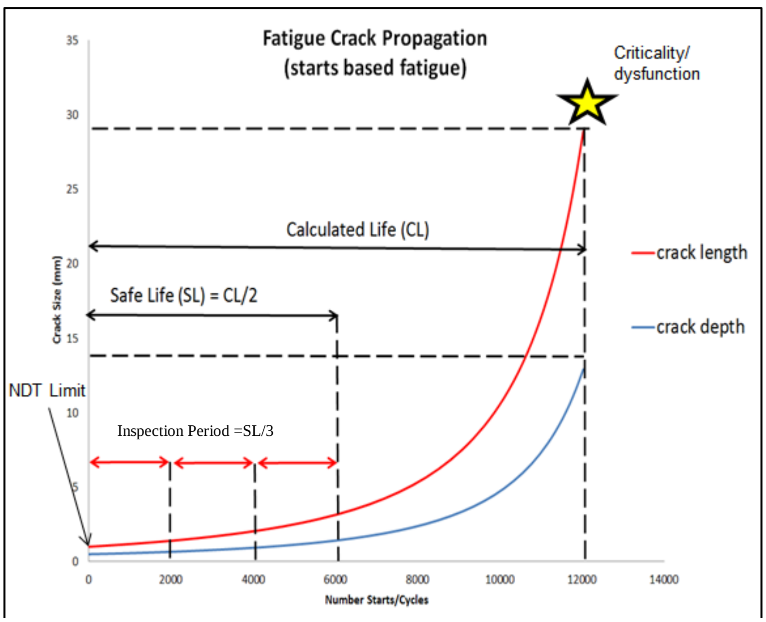

Figure 12: Example of derivation of inspection period.

Here the computed remnant life from an assumed initial defect (normally taken to be the detection limit of the NDT technique) is divided by a safety factor of 2. This provides a so-called 'safe-life'. The 'safe-life is computed to ensure the life is not influenced by the exponential (and therefore sensitive) part of the crack growth curve. The inspection period is then determined by dividing the safe life by an appropriate factor, in this case 3. This means if an existing flaw is present it will be safely detected on the next inspection before the flaw could potential reach a critical size.

By life assessing the critical locations, NDT techniques can be developed for each location and the inspection period derived depending on the life assessment for that location.

4.4 Fitness for Service Issues

After developing the life assessment model and tools, in service issues such as erosion and corrosion can be rapidly assessed. An example of this is seen below, for crests of a rotor disc eroding due steam impingement / leakage. Figure 13 shows an example of such erosion.

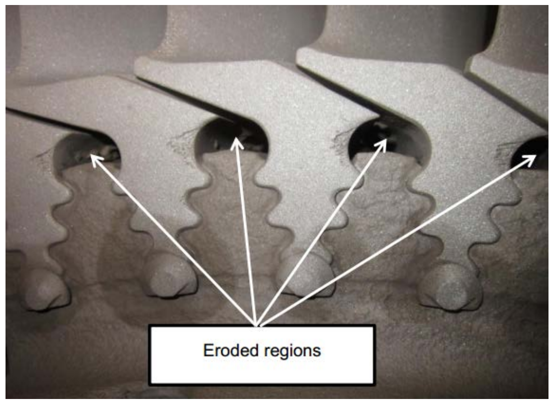

Figure 13: Illustration of erosion to disc rim/crest.

Figure 14 shows modification of an existing finite element analysis to account for such erosion. The objective being to determine how the stress state in the disc changes due to the presence of erosion.

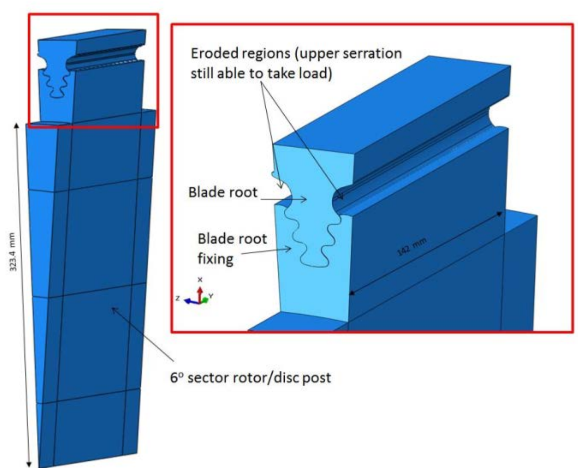

Figure 14: Modelled geometry with erosion taken into account

Figure 15 shows the results for stress computed by finite element analysis for this example.

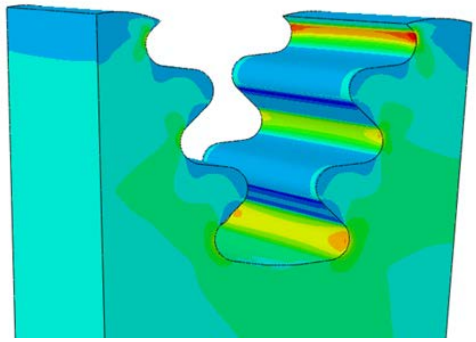

Figure 15: Finite element stress analysis results determining stresses in root fixing with erosion present.

Based on the computed stresses in the disc, the remnant life of the disc could be assessed and a judgment as to whether or not to return back to service.

This concept extends to corrosion, and fatigue cracks where cracks or corroded regions can be rapidly incorporated into existing models to assess the effect of their presence and allow decisions be made as to whether repair or return to service without remediation, which obviously saves money and time.

5. Conclusions

Geothermal steam turbine rotors and blades can experience a range of damage mechanisms:

- Sulfide Stress Cracking and Chloride Stress Corrosion Cracking.
- Moisture Induced Damage:
  - Impact Erosion.
  - Blade Trailing Edge Erosion.
  - Water Washing Erosion (Throttling).
- Foreign Object Damage / Domestic Object Damage.
- Solid Particle Erosion (Abrasion), Scale Formation and Surface Deposits.
- Component Rubbing / Fretting (Corrosion and Fatigue).
- Fatigue Failures.
- Vibration.

Inspection procedures are available to identify and quantify these damage mechanisms. The information obtained from a targeted condition inspection program can be used as input for rotor life management exercises that model critical turbine rotor and blade components and locations activities to help to determine the remaining lifetimes.

On completion of the rotor life management exercise it should be possible to develop component inspection management programmes for the rotor that are based on a sound technical approach as outlined in technical publications based on fitness-for-service guidelines (i.e. BS7910 or API 579[7]).

Knowing the current condition of the rotor and steam path parts and damage mechanisms, it is possible to specify future inspection frequencies for the rotor dependant on the current condition and the damage detected during the condition assessment and inspection. This process can provide the operator a safe re-inspection interval based on the reserve factor method as outlined in BS7910 as well as an overall remaining life of the rotor. This proven process enables planned outage intervals to be extended thereby increasing efficiency in operation of geothermal power plants.

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