WAYANG WINDU POWER STATION TURBINE ROTOR REPAIR REVIEW

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ABSTRACT

This paper reports the findings of a review of the repair options for the rotor removed in 2012 from the Star Energy Wayang Windu Geothermal Power Station 110MW Unit 1 Turbine. The rotor was replaced as a result of an assessment by the Fuji, – the Original Equipment Manufacturer (OEM), of the erosion damage found in the 2009 overhaul. A new rotor was installed and the original rotor was set aside as an emergency spare.

ProGen Ltd. conducted an independent technical review[1] of the spare turbine rotor in March 2013 to assess the current condition of the rotor, confirm those findings of the previous inspections[2,3], highlight any further issues, explore possible repair options and undertake an economic analysis of those viable repair options.

Each side of the central body of the rotor (stages 1-5 and stages 6-10) was found to have severe damage to the interstage sealing zones which could impact on the axial support for the rotating blades. It was concluded that the rotor could be refurbished to provide a fully serviceable spare for the remaining operational units. Several repair methods including submerged arc welding, laser cladding and a machined bush ring were investigated for the restoration of the rotor. The results of the discounted cash flow (DCF) analysis showed that all three of the viable repair options provide a more economical solution when compared to a new replacement rotor. In addition, the analysis showed the benefit of applying high velocity oxy-fuel (HVOF) coating spray at each overhaul.

The next stage of the repair options review is to develop and issue a request for tender (RFT) document to service workshop providers. This will allow further exploration of the feasibility and costs of the various options and also open the market for further potential options.

1. ROTOR HISTORY

The rotor was commissioned in the Star Energy Wayang Windu geothermal power station 110MW Unit 1 Turbine in 2000. A picture of the rotor in a maintenance stand is shown in Figure 1.

Figure 1 – Turbine Rotor

The turbine nameplate data is listed in Table 1.

Table 1 - Nameplate Data

FUJI - single cylinder, double flow, dual entry, condensing type.	
Rated output	110,000kW
Rated steam pressure	10.2 bar abs
Rated steam temperature	181°C
Exhaust pressure	0.12 bar abs
Blading configuration	8 stage double flow reaction type
Rated speed	3000 rpm
Manufacture date	1998
Commencement of operation	6 June 2000
Operating profile	Base load >97% NCF
Operating hours	TBA
Rotor weight	47 tonne

The rotor was removed in June 2012 and replaced with a new rotor as part of a scheduled overhaul. The decision to replace the rotor at the next scheduled overhaul had been made post the 2009 overhaul in conjunction with Fuji (OEM). The decision was based on inspections made on the rotor condition which showed that erosion damage to the rotor had advanced to a point where continued operation could be risking a more catastrophic event such as losing a blade and causing major damage.

ProGen Ltd. was requested to undertake an independent technical inspection of the rotor, research different repair methodologies and potential improvements, formulate a financial analysis of the repair options and develop a full report detailing the findings.

The inspection was to focus on worn sections of the rotor body, damage to the sealing mechanisms, journals, gland bushes, thrust collar, couplings and blades. This was to include reviewing previous inspection reports, condition assessments and recommendations, interviewing technical staff and organising additional tests as required.

The research was to investigate potential approaches to repairing the rotor and blades and then assess the viability of each option. It was to include assembling financial information and workshop options for the repairs. Advice was to be sought from various experts in the field of restoration of geothermal steam turbines who could assist with the development and assessment of the options.

A discounted cash flow financial model was to be developed for the repair options and potential improvements. A review of the operating philosophy for the geothermal units and rotors was to be included to ensure that the model reflected optimal operation and repair strategies.

2. ROTOR INSPECTION

The turbine rotor and staging is shown in Figure 2.

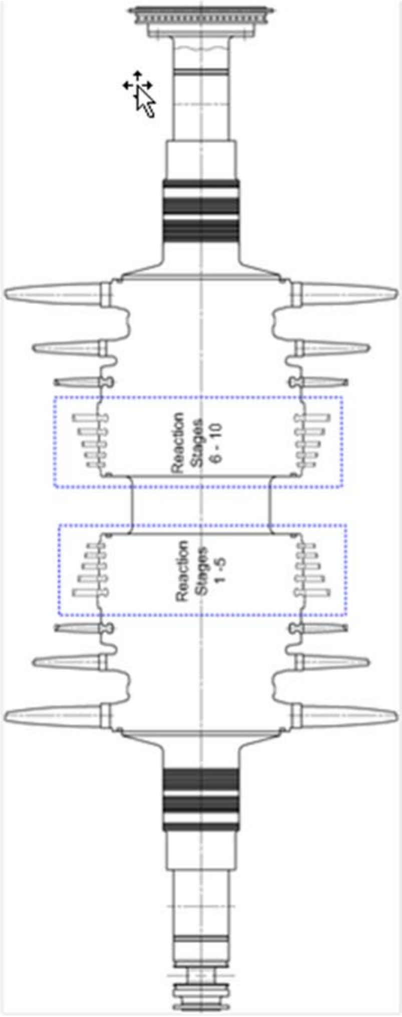

Figure 2 – Turbine rotor and staging

2.1 Rotor Body and Interstage Erosion

The inspection of the rotor[4,5,6] revealed that the critical damage to the rotor body was situated in the reaction stages, 1 to 5 and 6 to 10 sections of both flows. The blades of these stages are provided with shroud blocks, integral with the blades.

The major erosion damage to the rotor is located on the rotor body between each of the reaction stages. Several of the seal "J" strips in these sections have been eliminated through the erosion of the parent metal surrounding the caulking groove. An example of this erosion at interstage 3 is shown in Figure 3.

Figure 3 - Erosion at Interstage 3

The erosion has encroached into the blade support slot at almost all blade locations. Note that the OEM (Fuji) has indicated that the blade support shoulder is critical to the security of the blades.

The erosion of the blade support shoulders is most noticeable in the middle reaction stages of each of the flows. This shoulder erosion has progressed since the 2009 overhaul to the point where stages 2-4 and stage 8 were outside the tolerances specified by the OEM (Fuji) as shown in Figure 4.

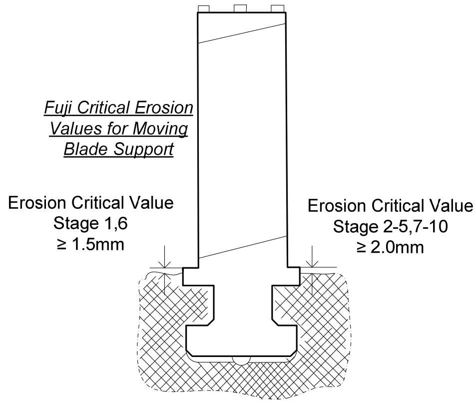

Figure 4 - Erosion at blade support slots

The erosion of the seal areas of the main oil pump (MOP) end section is noticeably more advanced than that of the generator end as shown in Figures 5 and 6. Of the 18 seal strips that were originally installed at each end of the rotor, only 9 remain in the MOP end whilst 16 remain in the generator end.

A notable point with the generator end is that almost all of the caulking grooves had now been fully exposed on the upstream side. As a result there was a high potential for the seal strip caulking being dislodged in the near future should the rotor be returned to service in its current condition. It was also likely that a number of the adjacent strips may also be dislodged and results in major consequential damage to the blading components.

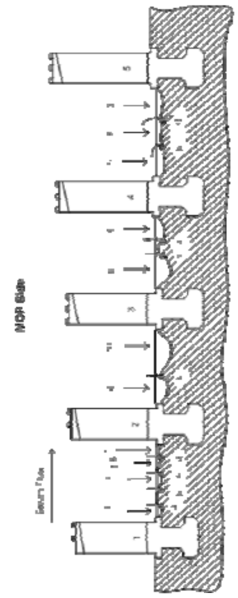

Figure 5 – MOP side erosion

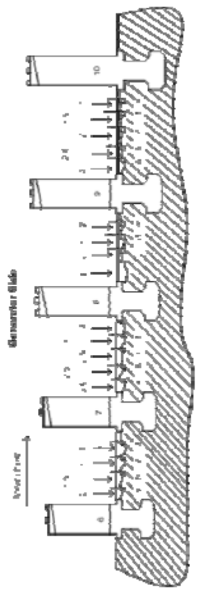

Figure 6 – Generator side erosion

2.3 Reaction Stage Blade Observations

With the rotor being presented in a cleaned condition it was not possible to view the rotor blading in its post running condition. In addition there was no available assessment of the thickness and coverage of any deposits or the chemical composition of such deposits.

The blades were in a reasonably good condition with little obvious erosion and only light corrosion pitting on some of the blade faces.

Closer inspection revealed that the trailing edge of the blades have a slight hook curving into the port of the blade. The edges of the blades are mostly thinned to a fine knife-edge which has weakened the stability of the exit of the port. The slightly ragged trailing edge can be seen in the Figure 7.

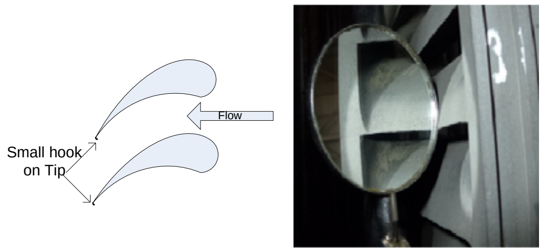

Figure 7 - Blade tip trailing edge erosion

The hook shape has been formed from the deflection of the fine edge by either the grit-blast cleaning of the blades or the steam/water droplet and (at times) deposit laden media passing through the stages. The formation of this edge was not able to be checked prior to the blast cleaning of the rotor so the actual "as found" shape of the trailing edge could not be confirmed

Most of the blades exhibited some erosion on the pressure faces. This erosion is limited to the inner and outer radial extremities of the port. The blade in Figure 7 shows a slight curve on the outer end of the trailing edge indicating the erosion. This curve is replicated on the inner edge of the port wall as well.

There were signs of corrosion pitting on both the pressure and suction faces of the blades. This pitting is mostly very light and doesn't cover the complete blades.

2.3 Erosion Mechanism

The bulk of the damaging erosion is situated in the rotor stages after the first two sets of rotating blades of each flow. The erosion is more significant on the rotor material rather than the seal strips, caulking material and blades. This is due to differences in hardness of each item.

It is presumed that the erosion is being caused by water droplets. As the steam is dried out by the pressure drop across the stationary blades, the water has been carried into the turbine. This carryover is either from incomplete scrubbing or inefficient drainage in the pipeline downstream of the scrubbers. The water is likely to contain geothermal minerals. These would precipitate as micro-particles of silica and salt as the pressure drops when the steam is bypassing the stationary nozzle. The particles would be the source of the aggressive erosion and corrosion. In addition NCGs in the steam can react with the water film at the first condensation point and generate acids (low pH) which can also attack the rotor. The circulation of this water, with or without evaporates is aggressively eroding the rotor material around the caulking strips ahead of the seal strip. As each of the seals is being eroded/stripped from the rotor, then more fluid is bypassing the nozzle increasing the erosive effects.

It is not known if the water droplets are being carried through the separator/steam strainer or they are forming with the localised conditions at the various stages. The OEM (Fuji) indicates in their 2009 and 2012 reports that the damage is resulting from low pH steam. This may have a contributing effect.

With the majority of the damage being located in the MOP end of the rotor, there is a question as to why this is the case. While it is possible for the blade carrier at the MOP end to be secured slightly out of alignment with the rotor, it was noted that the remaining seal strips bear no real evidence that there has been any significant contact with the stationary blading. However, it is possible that the damage is linked to earlier events where the clearances on the sealing mechanisms may have contributed to increased flows across the labyrinth stages at the MOP end. At least one other power station operating similar type turbines have had NDE tip seals ripped out and/or excessive wear on the tip seals from running up a hogged rotor.

An additional theory is that; the centre of the rotor sag is offset at the MOP end. When the rotor is uncoupled, the sag would be in the central section very close to the midpoint between the two bearing centres. However, the rotor stiffness would significantly change after bolting the rotor to the generator (which has two central bearings relatively close together as well as the large diameter coupling). This change in stiffness would then offset the rotor sag centre point towards the MOP end. It is also likely that there is a critical below operating speed. When the machine is run through the critical with a hog or sag, the tip seals in the first couple of interstages MOP side would be the bits most likely to rub. Once this then starts, then it would just accelerate the wear. This rubbing could be indicated by rub marks on the diaphragm tip seals or groves worn into the rotor blades.

As there is no interstage drainage capability within the HP blade carrier therefore any water that has formed, has to proceed through each of the stages before there is any opportunity for it to be siphoned off into the drainage cavities. If the steam turbine process follows normal design thermodynamics, then even dry steam entering will be 6% water by the end of the HP section and first drain. Spontaneous condensation of water droplets from super-saturated steam (the Wilson line) occurs at about 3% wet so there will be significant quantities of water flowing through the turbine blading and sealing areas.

An assumption could be made that; the major cause of the erosion is from within the system, the result of steam borne conditions eroding the rotor material. A separate investigation needs to be undertaken to research the erosion mechanisms to see if changes can be made to alleviate the conditions causing the damage. At this point the assumption could also be made that the erosion process will continue on the new rotor installed in Unit 1.

2.4 Turbine Rotor Remaining Parts

Additional issues were noted during the inspection and are listed below. Note repair options for these issues have not been included in this paper.

The blade shoulder behind the R5 and R10 row blades has a gap of between 0.15 and 0.30 mm. Advice should be sought from the OEM on the significance of this gap.

The root fixing location of both sets of LP2 blades have an erosion groove on the upstream rotor side of the fir tree root. The groove is the result of the impingement of the discharge from the NDII blade ring interstage seal. This impingement is also eroding the whole of the leading edge of the rotor steeple. An application of HVOF protective coating at each survey interval would benefit this area and arrest the erosion.

There is an impingement groove near the upstream base of both of the LP3 wheels which has been caused by the discharge of the NDIII interstage seal. This damage will need dressing and coating with HVOF at each survey interval.

The exhaust side of the LP3 wheel has suffered impingement of the rotor blade root steeple and the leading edge of the steeple is eroded. This area should be considered for an application of an erosion resistant coating.

Both sets of gland bushes are showing signs of excessive erosion on the castellations. There are grooves into the rotor resulting from debris build-ups that have cut their way into the rotor in at least two locations. These bushes need to be rebuilt and then coated with an erosion resistant HVOF coating.

3. ROTOR REPAIR PROCESS AND OPTIONS

For the rotor to be repaired then the stages 1 to 10 will need to be de-bladed. The de-blading will need to be conducted in a manner that preserves several blades from each row so that they can form a pattern for reverse engineering should that path be necessary. If the blades are not to be recovered then the remainder of the blades can be removed by machining or similar process.

The next stage of repair of the rotor is likely to require the removal of up to 10mm of material from the centre portion of the rotor to clear away the eroded material. The rotor blade “tee slots” will also need to be cleaned at this point. A full NDT check of the bare sections of the rotor including the “tee slots” should be conducted prior to proceeding further as this may indicate that cracking or other damage is of an extent that a repair is not viable and the rotor is to be scrapped.

Several repair options have been suggested for dealing with recovering of the erosion of the centre portions of the rotor. These options range from the fully fusion welded repair to the use of wire feed, thermal spray applications. The repair options are as follows.

3.1 Submerged Arc Weld Repair

The submerged arc repair process has been adopted and refined over the years by a number of OEM companies as well as major service companies specialising in steam turbine rotor repairs. This process uses a fully fusion-welded overlay to rebuild the eroded surfaces.

The welding would normally take place while the rotor is suspended and rotated in a lathe to reduce the potential for distortion. Some workshops are able to suspend the rotor vertically for this purpose. The welded rotor areas are then normalised and NDT tested prior to machining.

This process lends itself to the addition of materials more suitable for minimising the effects of the erosive steam conditions. It has been assessed that there could be the potential for some distortion of the thinned areas of the tee slots. A better understanding of the risks of this distortion would need to be developed when the dimensions of the remaining material over the slots is able to be measured.

The USD $2,500,000 approximate cost used for this option is based on either repair in a local workshop equipped with mobile machining, welding and balancing equipment or repair in an overseas workshop and including the packaging, shipping and repair. The machining/welding cost is USD $750,000 with the rest of the cost associated with set up of a local workshop or transporting and shipping the rotor to an overseas workshop and new blades USD $1,000,000.

Advantages:

- Complete repair with materials resistant to the erosion / corrosion.
- Secure homogenous repair.
- Well tested on a number of rotor repairs supported by various OEM.

Disadvantages:

- Requirement for heat treatment.
- Limitation of workshops capable of conducting the work.
- Potential for distortion of tee slot form.
- May require the removal of some of the LP blading because of the heat treatment.

3.2 Laser Cladding Repair

This repair process is a complete micro fusion weld that can use various materials to achieve desired hardness and erosion resistance. While it has been used in Gas Turbines and clean steam blading repairs it is not known without further investigation if there have been repairs of this nature performed on geothermal turbine rotors.

The repair method will need to be carried out on a large capacity lathe similar to that required for the other methods. The process is performed by applying the wire and or powder fed material into a localised light beam that generates minimal heat.

It is expected that the benefits of this method will be; little distortion, reduced likelihood of needing heat treatment and the application of erosion resistant material with excellent mechanical strength properties.

A general comment from those in the industry who are using this process for repairs and modifications is that the Laser Cladding technology will become much more dominant in the industry in the near future as the equipment for the application becomes more available to those who are looking to move from the older technology type of repairs.

The USD $2,000,000 cost includes new blades.

Advantages:

- Potential for a weld process that does not have a requirement for heat treatment resulting in significant time and cost savings.
- Able to take advantage of using materials that are resistant for erosion / corrosion.
- Secure homogenous repair.

Disadvantages:

- Not enough knowledge about the process to confirm complete suitability at this stage.

3.3 Attached Bush Ring Repair

This process involves the installation of purpose built bush rings, secured to the rotor after the machining back to remove the erosion indications. The bush rings would likely be installed in close matching halves then secured to the rotor by means of screws or rivets. The completed installation would then be machined to the correct tolerances with the addition of the sealing grooves. The seal strips can then be installed through the fasteners to lock all in place.

This method would also lend itself to using more erosion resistant materials to prolong the rotor life.

This method of repair is currently the favoured approach of the OEM. The USD $4,000,000 approximate cost includes new blades.

Advantages:

- No welding on the rotor body.
- Use of erosion resistant materials.
- Process is supported by OEM and is currently employed in other stations for repairing diaphragm spill strip seals.

Disadvantages:

- Question over the integrity of the repair given the requirement for enhanced security of the fasteners.
- Question whether the repair provides the level of lateral support to the blades that is required.
- Reduction of material over the “tee slots” could weaken the attachment.
- Need to investigate further detail about the repair process to evaluate the risks.
- Question over integrity of rotor diameter being reduced.

3.4 Thermal Spray Coating Repair

The thermal spray process involves the application of wire fed molten material propelled at high speed onto a cleaned and prepared rotor surface. The spray coating is mechanically bonded to the substrate by the cooling of the coating adhering to the specially prepared rotor surfaces.

This mechanically bonded material is than able to be machined back to the required dimensions and prepared for the installation of the sealing strips. The coating is normally secured with a thin layer of highly wear resistant HVOF tungsten carbide.

This process has been used to varying degrees in a number of turbine rotor repair applications, particularly in the Philippines. It has been used for restoring rotor gland bushes and other surfaces.

This repair process would appear to be the least favored by the repair experts that have been consulted so far. The mechanical strength of the bonding is questioned as the volume of material required to be added in this example (up to 10mm) would seem to be up to 5 times thicker than the normal limit applied.

Costings for this repair option have not been included as further research would be needed to prove this as a viable process for the repair of the rotor.

Advantages:

- Currently used for rotor repairs in Philippines.

- No heat treatment required.
- Lower cost of repair.

Disadvantages:

- Thickness of the overlay required expected to be too much for the mechanical stability of the repair.
- Lower mechanical strength than other options.
- Doubts about the amount of lateral support that this method will be able to provide for the blades.
- More research required into the viability of this technique.

3.5 Supply of New Rotor

The replacement with a new rotor has been used as the base case for comparison against the repair options. The cost of a new rotor is USD $7,000,000.

4. FINANCIAL ANALYSIS

A discounted cash flow (DCF) analysis was undertaken for each of the three viable repairs options (Laser, Bush Ring and Submerged Arc) and compared against the base case of replacing the rotor every 12 years with a new rotor.

Several key assumptions have been developed for the proposed operating philosophy of the geothermal units. These assumptions include:

- That the geothermal units will have an operating life of 30 years. Thus Unit 1 will cease operation in 2030 and Unit 2 in 2039. While it is possible that the Units may continue operating past these periods it has not allowed for so that a simple model could be developed.

- That the geothermal units will be overhauled every 4 years. Currently the units have been overhauled approximately every 3 years but there are plans to extend this to 4 years and potentially 5 years.

- That the life of a rotor is 12 years as has been experienced on Unit 1. The currently operating and steam conditions are such that it may not be possible to extend the rotor life beyond this period without undertaking significant process or equipment improvements. This has not been allowed for so that a simple model could be developed.

- That the life of a rotor can be extended to 20 years if HVOF coatings are applied at the time of this repair and every 4 years thereafter. Recent experience with HVOF coatings have shown that they will assist with delaying the onset of the erosion experienced in the reaction stage blading and gland bush areas of the shaft. The coatings have a limited life and will need to be re-applied at each overhaul interval. Costs for HVOF coatings are assumed to be USD $50,000 to apply as part of this repair and USD $125,000 (2013 $) at future overhauls.

- That all three viable repair options will return the rotor to an as new state. This is based on advice from the different Service Providers and technical support staff approached as part of this review. Thus the repaired rotors have the operating life of 12 years without HVOF coating application or 20 years with HVOF coating.

The results of the DCF Analysis (refer Table 2) show that the repair options provide a more economical solution when compared to a new replacement rotor e.g. a Submerged Arc repair only (with no HVOF) will cost $4m vs. a new rotor only (with no HVOF) of $11m. This result is driven by the fact that the repaired rotors have the same operating life of a new rotor. Thus in a DCF Analysis a repaired rotor will always have a lower net present value (NPV) as the capital outlay will be significantly less than a new rotor. This assumption should be strongly challenged at the next stage of the review when a RFT is issued and suppliers are required to state the expected operating life for each repair option.

Table 2 – DCF Analysis Results

Repair Option	Initial Capital Investment	2nd Capital Investment in 2025 (if required)	DCF NPV over 27 Year life to 2039
Submerged Arc Weld Repair Only	$2,500,000	$5,030,491	-$3,996,223
Submerged Arc Weld + HVOF Repairs at each Overhaul	$2,550,000	Not Required	-$3,021,182
Laser Cladding Repair Only	$2,000,000	$4,024,393	-$3,216,096
Laser Cladding Repair + HVOF Repairs at each Overhaul	$2,050,000	Not Required	-$2,558,219
Bush Ring Repair Only	$4,000,000	$8,048,786	-$6,336,605
Bush Ring Repair + HVOF Repairs at each Overhaul	$4,050,000	Not Required	-$4,410,071
Replace with New Rotor Only	$7,000,000	$14,085,375	-$11,017,367
Replace with New Rotor + HVOF Repairs at each Overhaul	$7,050,000	Not Required	-$7,187,848

In addition the DCF analysis showed the benefit of applying HVOF coatings at each overhaul e.g. a submerged arc repair (with HVOF) will cost $3m versus a submerged arc repair only (with no HVOF) of $4m. Typically HVOF coating could provide between 15% to 35% savings in NPV over the operating life of the Units

The following assumptions have been used in the DCF financial analysis

1. Inflation Rate = 6%
2. Discount rate = 8%
3. Life of each Geothermal Unit is 30 years (Unit 1 installed 2000, Unit 2 installed 2009)
4. Each Unit is overhauled every 4 years
5. Life of Rotor with no HVOF repairs is 12 years (as experienced on Unit 1)

6. Life of Rotor with HVOF repairs is 20 years (based on experience where HVOF coating applied)
7. Costs to apply HVOF to the planned repaired rotor will only be an additional $50,000 as the majority of the cleaning and preparation work will be done as part of the repair
8. Where HVOF coatings are to be applied at a later overhaul then this will necessitate the operating rotor being swapped out with spare at each overhaul
9. HVOF repairs to a swapped out rotor are based on cost in 2013 of $125,000 and would occur at every overhaul (4 years)
10. All three repair options provide the same life as a new rotor - 12 years with no HVOF or 20 years with HVOF
11. All costs are in USD

5. ROTOR REPAIR RECOMMENDATIONS

5.1 Reaction Stage Rotor Body Repair

The repair of the sealing and blade support sections of the rotor can be feasibly repaired by utilising a number of options. This is a more economical solution compared to the purchase of a new rotor. Based on a quality repair being achieved the life of a repaired life will be the same as that of a new rotor.

Expert technical support will be required to assist in the evaluation of the chosen repair process to ensure that it meets the Star Energy criteria for the use of the spare rotor.

5.2 Reaction Stage Blading

All currently explored and recognised repair options are highly likely to require the removal and installation of the turbine blades. It is also assumed that a large proportion of the removed blades will be unsuitable for replacement into the repaired rotor. This would mean that a blading contingency plan will need to be developed. One option could be to purchase a full set of blades and use what is necessary, holding the remaining as spares for the next two rotors should they be required. It may also be preferable to plan to replace all HP section blading and therefore save significant time in the removal process of the existing blades.

It is suggested that an allowance is made for the removal of a portion of the reaction stage blades to allow for the reverse engineering of these blades if required.

5.3 Application of HVOF Coatings

Implement the application of erosion protection technology such as HVOF thermal coatings for future overhauls. This form of erosion protection will assist with delaying the onset of the erosion experienced in the reaction stage blading and gland bush areas of the shaft. The coatings have a limited life and will need to be re-applied at each overhaul interval. The DCF Analysis has shown the benefit of applying HVOF coatings at each overhaul Typically HVOF coating could provide between 15% to 35% savings in NPV over the operating life of the Units.

5.4 Next Stage of Repair Option Review

It is recommended that the next stage of the review of the repair options is to develop and issue a Request for Tender (RFT) document to selected Service Workshop Providers. This will allow for the exploration of the feasibility of the various options outlined above and also open the market for further potential options. It is more likely that the most suitable repair will be derived from the commercial tendering process provided that the tender documents are written so that there is full disclosure of the repair procedure. These repairs can then be fully assessed and all of the risks considered. In addition more detailed cost review can be conducted based on information supplied for either local or overseas repair for each option.

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Terry Ward – Repair Support Engineer, Gas Turbines, Air New Zealand, Auckland

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