Operational Warning Signs, Root Cause Evaluation & Restoration Strategy for a Large WTE Steam Turbine

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Presenters

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Agenda

Pinellas County, Florida

280
Square miles

24
Incorporated municipalities
Largest: St. Petersburg at 260k+

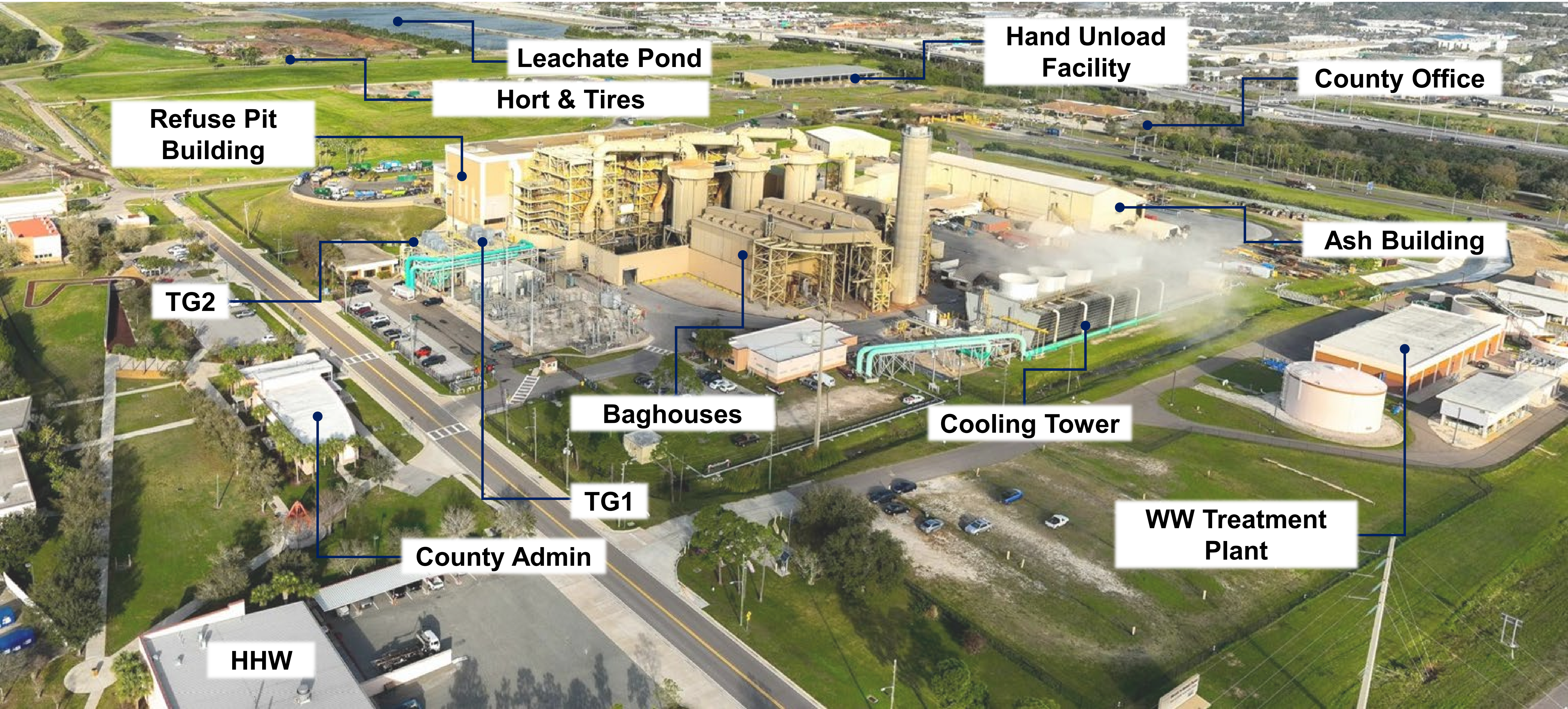
1M
Residents
2025 Census

~3,500
People/sq. mi.
Most densely populated county in FL

~6 lbs.
MSW/Resident/Day

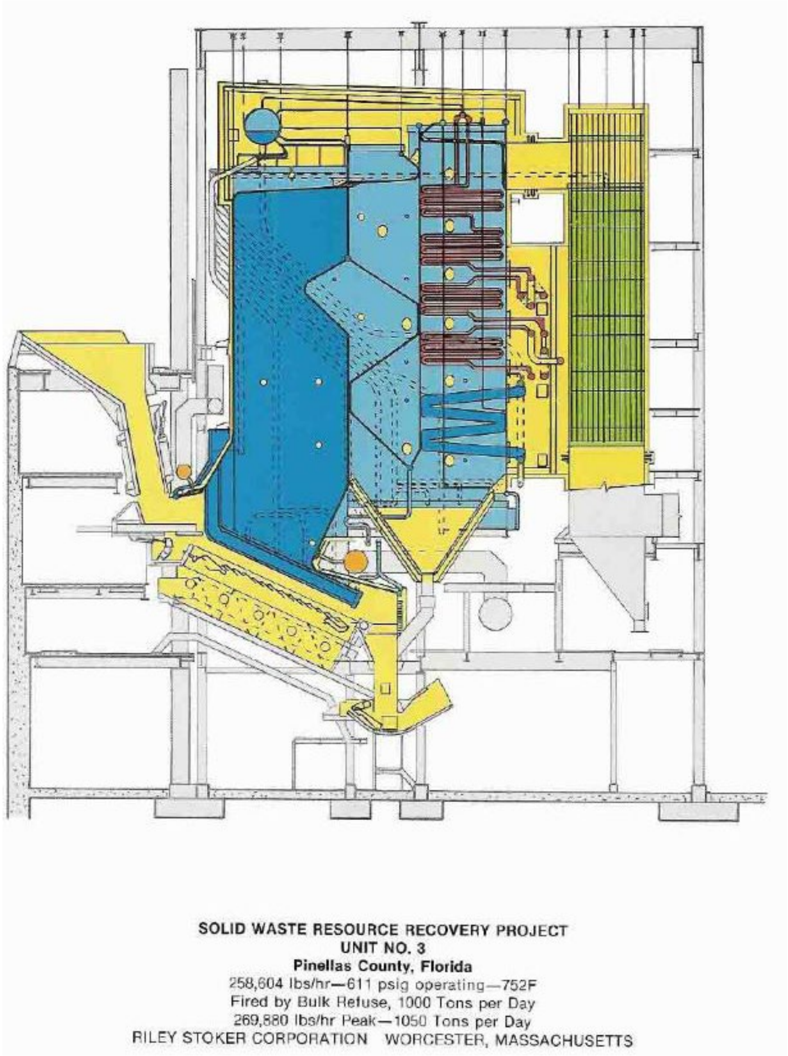
01
Facility Information

Pinellas County Solid Waste Disposal Complex

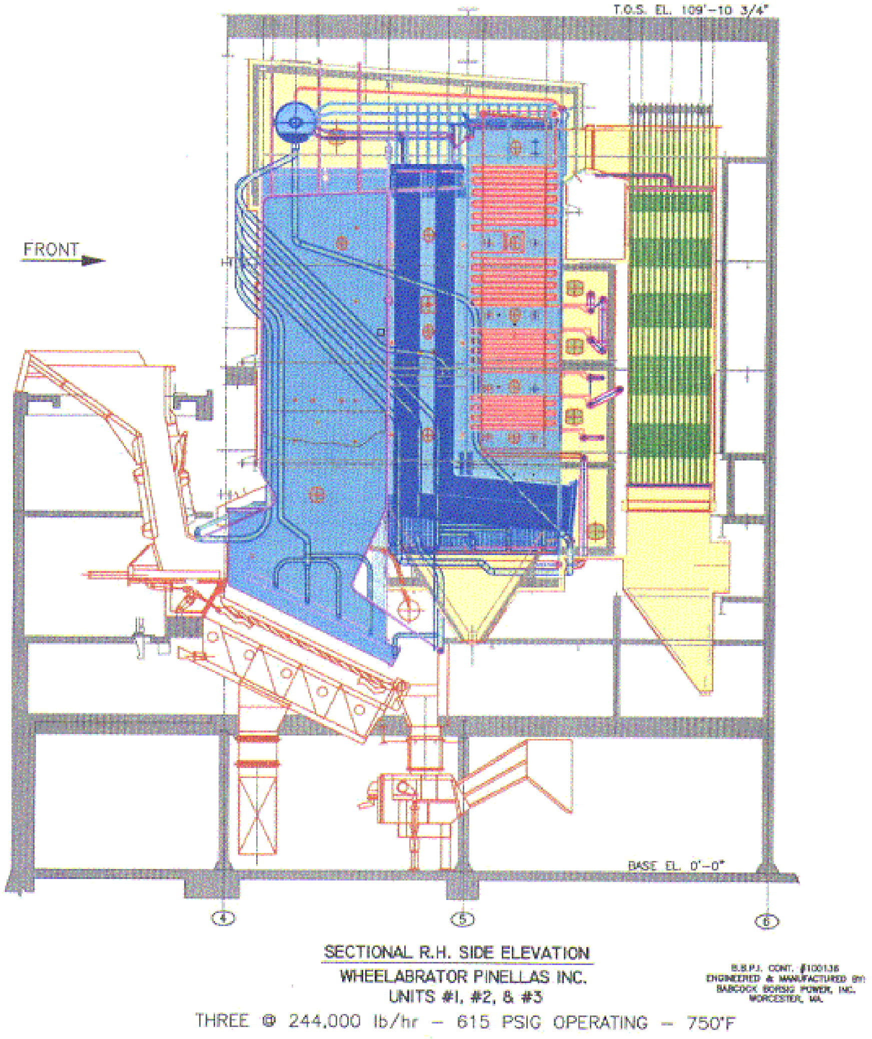


Facility Background

- 710 Acre Site (Class I & III); perimeter clay lined barrier
- Started: 1983 Units 1&2; 1986 Unit 3
- Capacity: 3,150 tpd @ 1,050 tons per unit
- Net Electrical Capacity: 75 MW
- MCR: 244 kpph Rate Steam Flow @ 4,800 Btu/lb
- Steam Conditions: 750 Deg F, 600 psig
- 2015-2021 TRP Investment of $250M for Major Refurbishment
- 2001-2003: Capital Replacement Project (CRP)



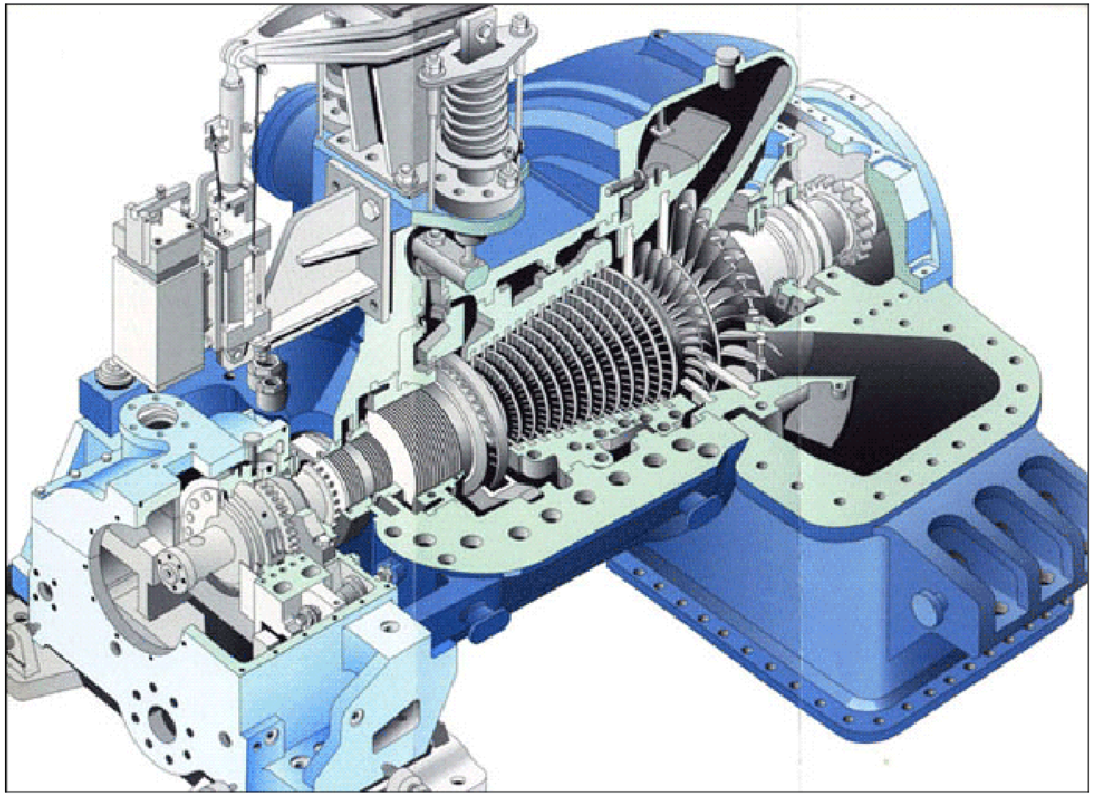
Old Boiler



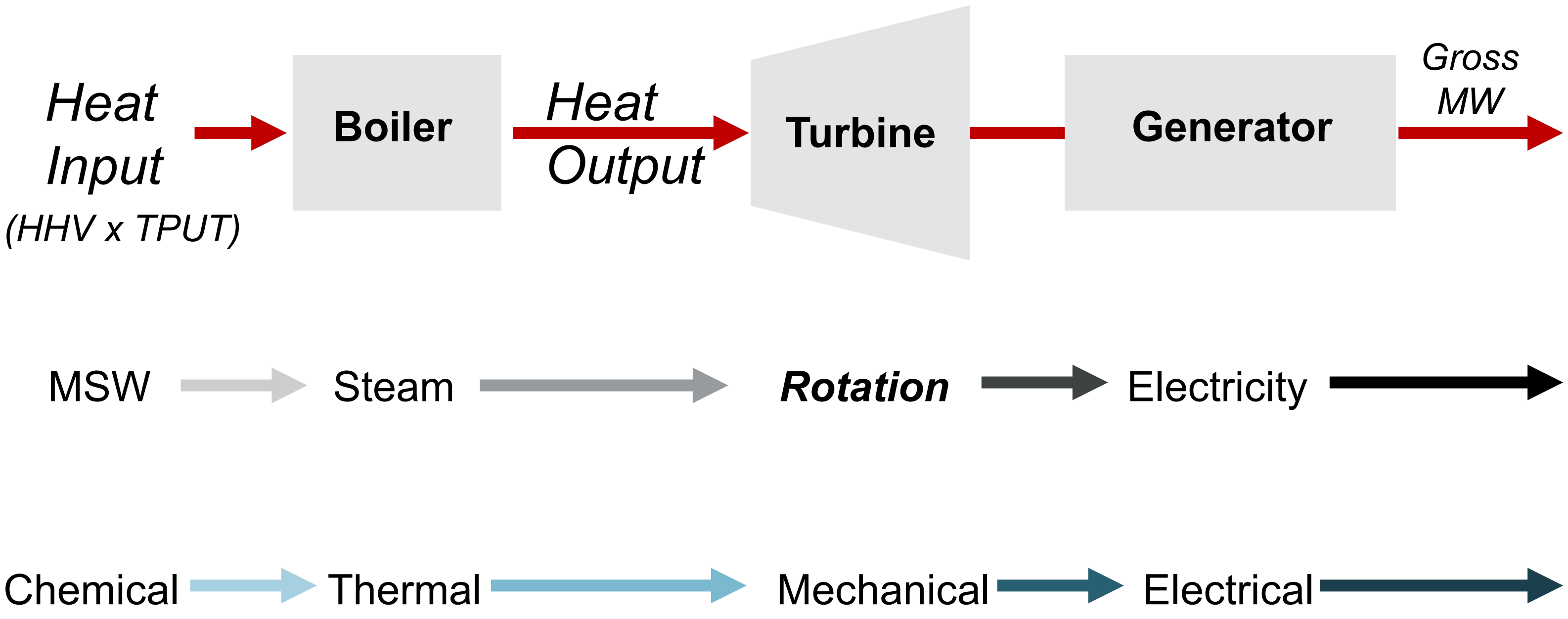
New Boiler

Turbine-Generator No. 1

- General Electric - 14 stage, straight condensing single flow design, 4 UC extractions
- **Nameplate Rating:** 50.5 MW, 59.9 MVA, 13.8kV, H2 cooled generator
- **Speed:** 3,600 rpm, mechanical trip @ 3,978; HP setpoint @ 3,850 rpm
- **Steam Conditions:** 600 psig/750 °F/3.5 InHgA
- TurboNet DASH-1 control system
- 4X Elliptical Bearings
- 2016 Steam Path Replacement



Key Steam Turbine Characteristics

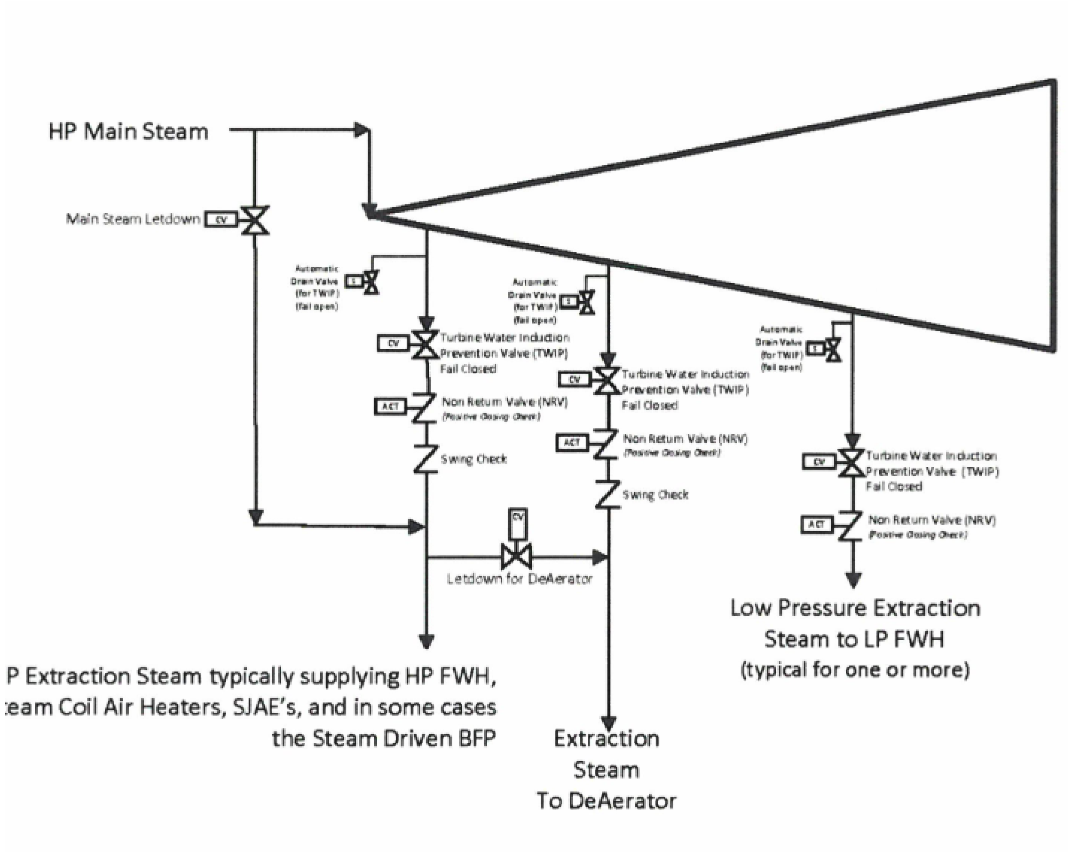


- Power output is approx. liner w/ mass flow of steam.
- Power output depends on initial (main steam) and final (turbine exhaust) enthalpy.
- Enthlapy drop x mass flow equals power out in Btu/hr.

Turbine clearances are extremely tight:

Measured in mils or 1/1000 of an inch (0.001”) – the thickness of a standard sheet of paper

TRP TWIP Project



- Executed under Service Agreement to comply with standard for Acceptable Operation Condition.
- Did not meet recommendations of ASME TDP-1 for min of two separate protective means for mitigating water induction.
- Only one protective design feature existed – emergency drain of vessel on H-H level.

Recommendations

- Isolate steam extraction lines
- Vessel emergency drain(s) operating under high-high level scenarios
- Water side isolation/bypass
- Appropriate extraction line drain provisions

02

TG1 Event Timeline

TG1 Failure Historical Timeline

Mar 2024

Spring Minor Inspection
- LP Hood Crack Repair
- 12” & 10” NRV Seat Eroded; No Repairs
- Abnormal Last Stage Packing (Possible Broken or Missing Springs)
- Possible T1 Bearing Wiped

Dec 2024

TS/R Spike in Bearing #1 Vibration

Mar 2025

TG Offline For Vibration Analysis
- Turning Gear Motor Not Responding
- Condenser Leak

April 2025

TG Offline
- #1 Bearing Metal Temp High
- CM 62274 Repair Thrust Bearing

May 2025

TG Offline (Sch Outage)
- Refurbish Journal Bearings Inc. Thrust Pads
- Primary Attemperator CV Leak
- #2 Vibration Probe Erratic Readings
- Repair Thrust Bearings

June 2025

TG Offline for Axial Thrust Alarm (72 hrs)
- Replace #1 Bearing Active/Inactive Thrust Pads

July 2025

TG Offline for Oil Level Tanks Switch Failure
- Repair U/H Casing Crack
- Replace Main Oil Tank Level Gauge (1/4 Full of Water)

FM Global Claim

Dec 2025

TG Offline for Major Outage
- Blade Liberation & DOD Stages 11/12
- Significant Pitting - Stages 2-8
- Loose Generator Wedges
- U/H Casing Crack
- Ship Rotor Offsite

April 2026

Rotor Returned to Site

Present 7/10/26

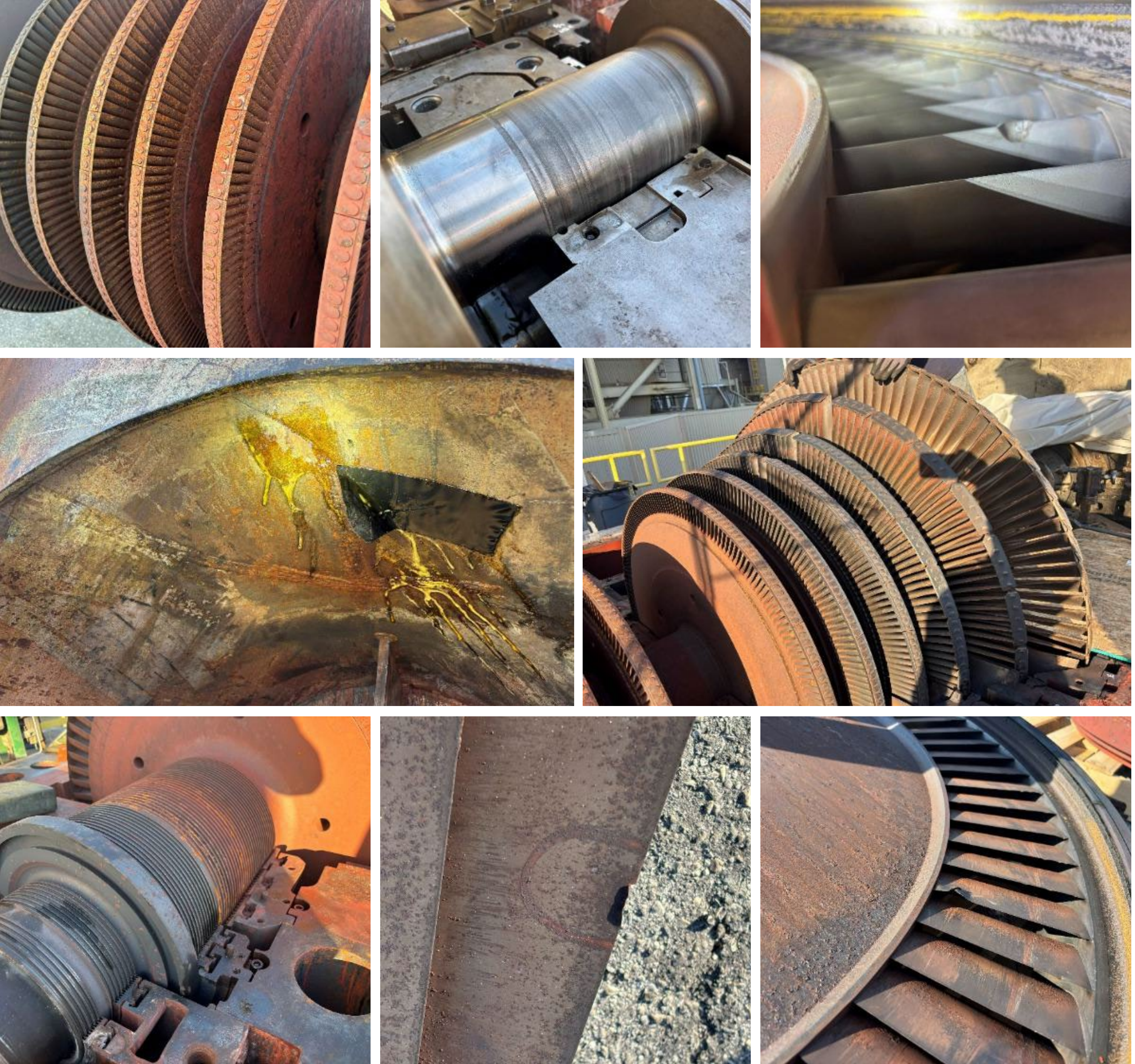
2026

Rotor/ Diaphragms Sent to GE

Vibrational Analysis

- In early 2025, plant operators reported concerns with haptic observations on external surfaces.
- Third-party investigation to verify TurboNet DASH-1 vibration monitoring system
- Determined if vibration levels pose a risk to TG reliability
- Max recorded rotor vibration approx. 3.5-4.1 mils p-p *(not generally considered damaging for equipment)*
- Verification testing confirmed accuracy of monitoring system

03 Initial Inspections & Repair



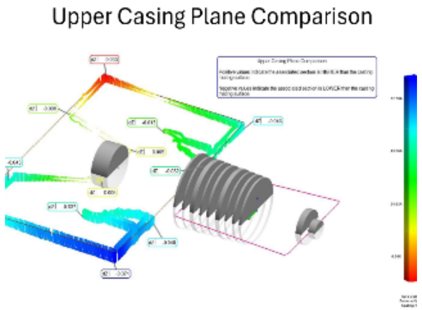
Initial Conditions

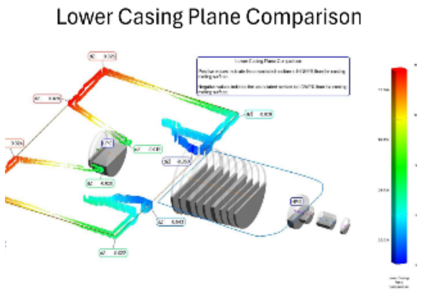
Dec. 3-5, 2025

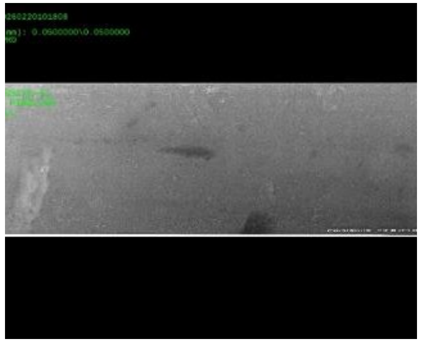
- Stage 11 blade liberation (2 blades)
- DOD on stage 12 diaphragms
- HP gland seal packing failure
- LP hood crack
- Pitting/corrosion on stages 2-8
- Minimal casing erosion

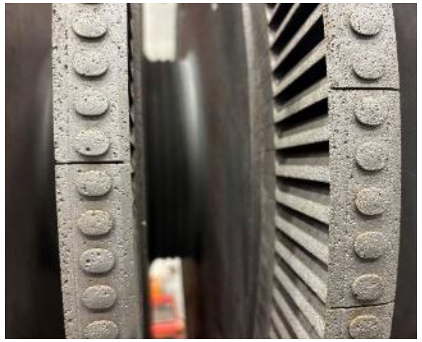
Field and Shop Repairs

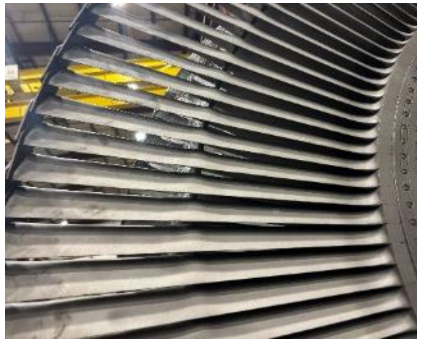
- Rotor shipped offsite for inspection, repair & low-speed balance
- Diaphragms 2-6 shipped offsite for inspection/repair; remaining sections addressed at plant
- LP hood crack evaluated, excavated & re-welded for third time
- U/L casing plane distortion and concentricity

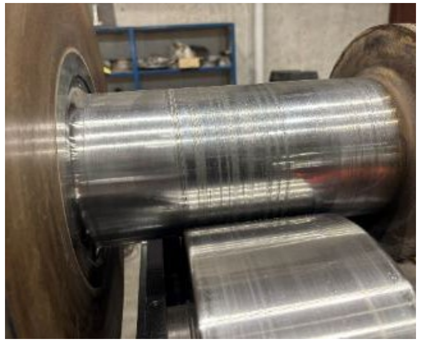




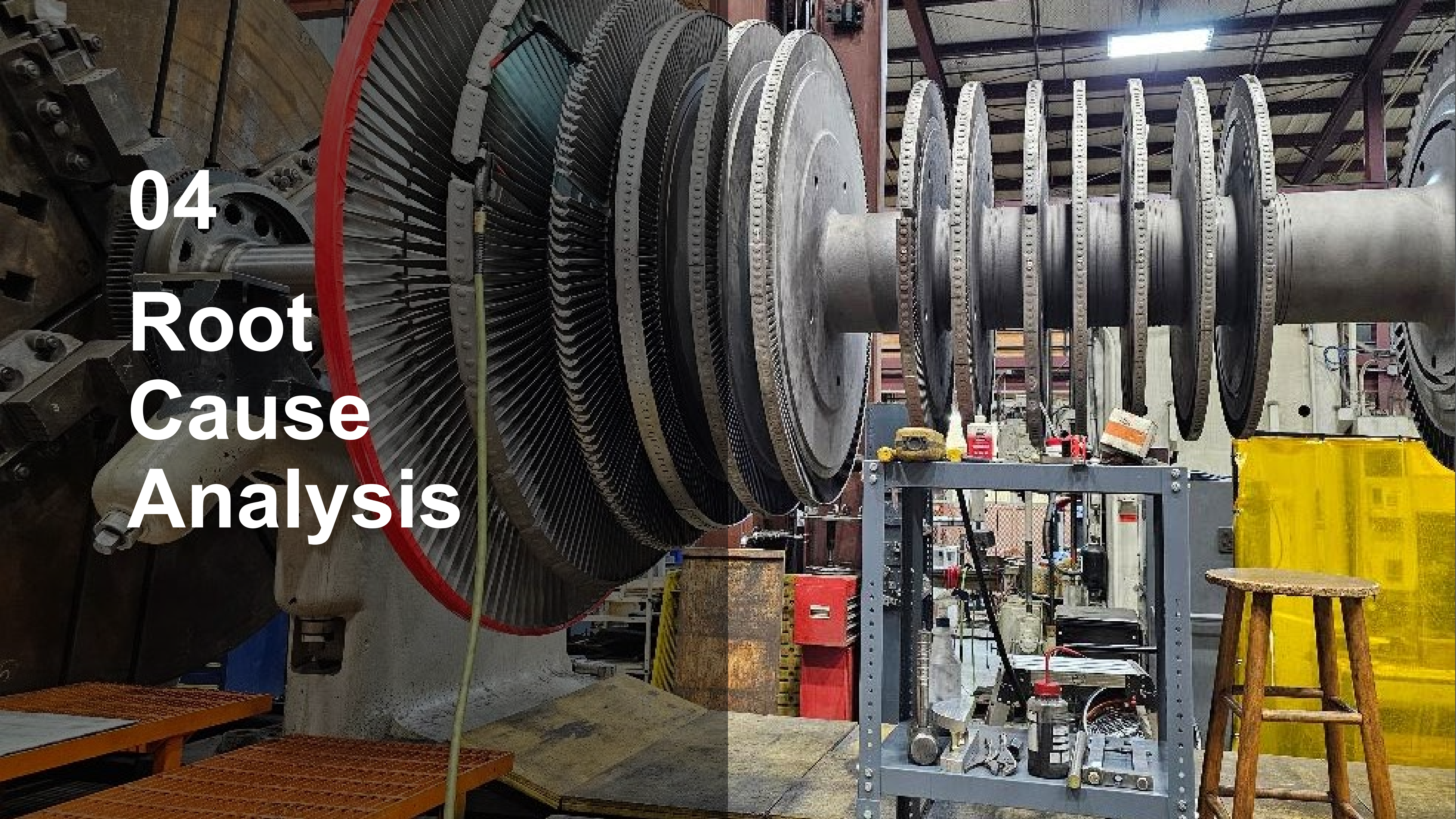




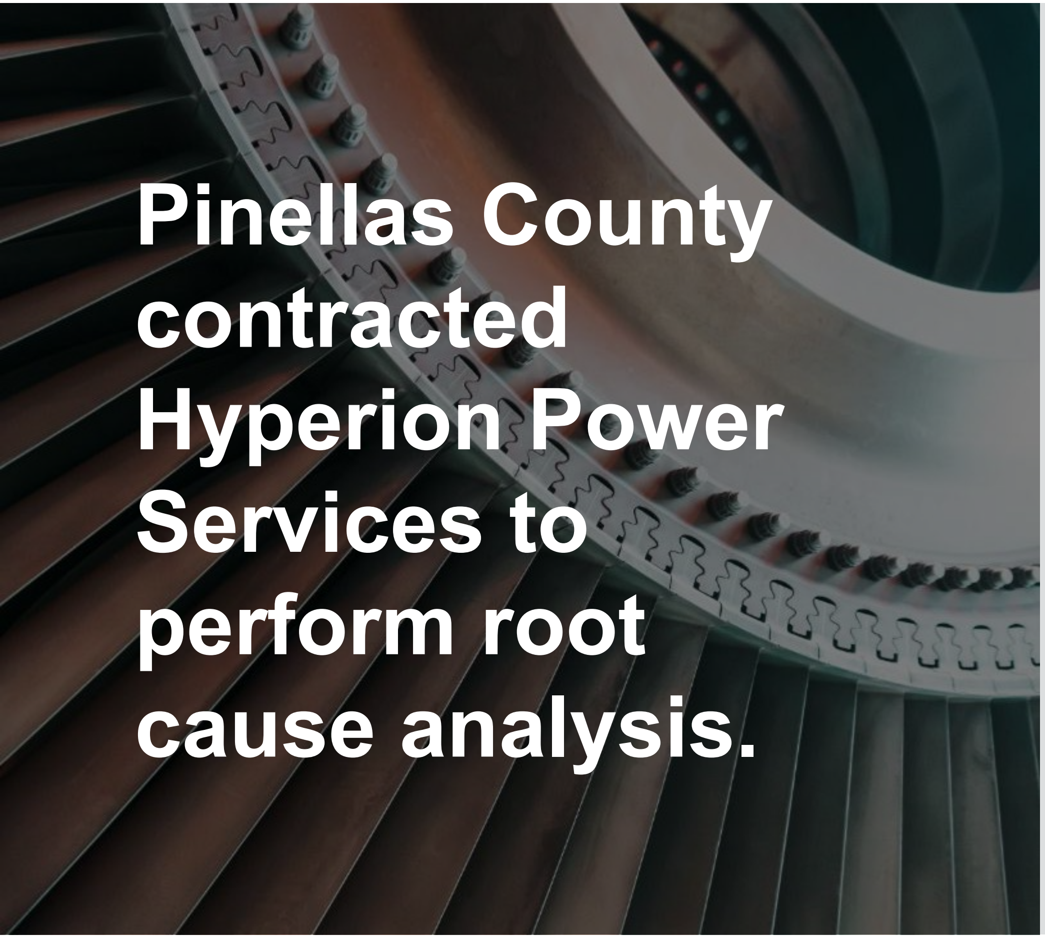




04
Root Cause Analysis



Third-Party Investigation



Pinellas County contracted Hyperion Power Services to perform root cause analysis.

- Specialized U.S. based subsidiary of the Hyperion Systems Engineering Group; turbine and boiler specialists.
- Utilized EPRI (Electrical Power Research Institute) Analysis Guide, Report 1014137 for root cause of ST turbine bucket failure.
- Standardized framework for investigating, identifying, and addressing blade failures due to vibration, fatigue, and corrosion.

Root Cause Analysis

Prevent future failures.

Restore reliable services as quickly as possible.

Assess reliability impact of blade cracking.

Engineering Analysis

Document Data Collection

- Initial condition
- Historical operating data
- Chemistry data
- Maintenance records
- OEM tech bulletins
- OEM design info moisture separator
- Trip logs/protection settings

Onsite Inspection/ Evidence Preservation

- Initial condition
- NDE
- Metrology/Clearances
- Sample Collection - *obtain deposits, obtain blades, gland seal & springs, filter debris*

Lab Analysis

- Deposit & Chemistry Characterization

  Bulk and surface, morphology/mechanism indicators, steam, purity/carryover

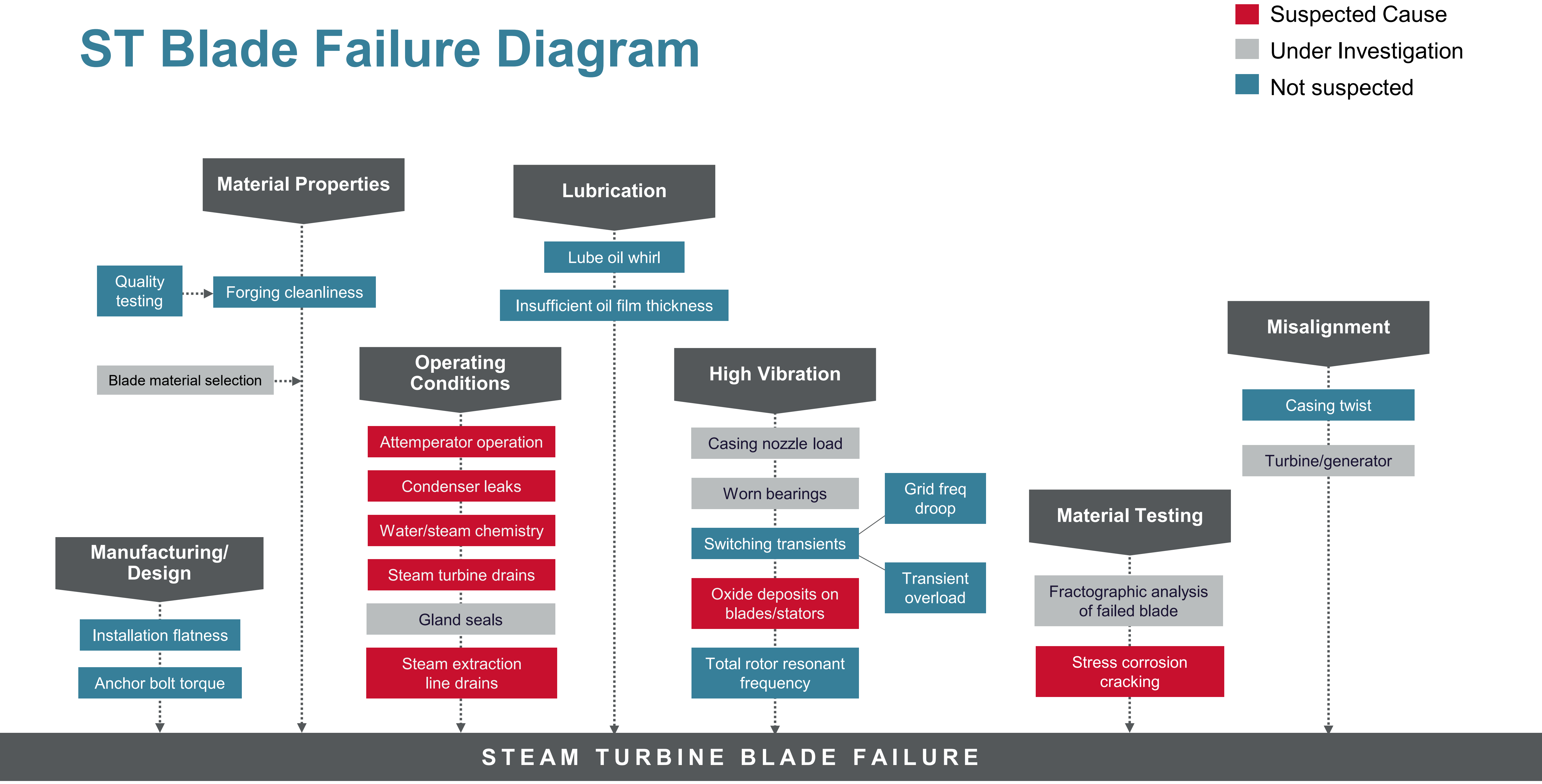
- Metallurgic Analysis

  Macroscopy, fractography, Microstructure/properties, surface condition, comparators

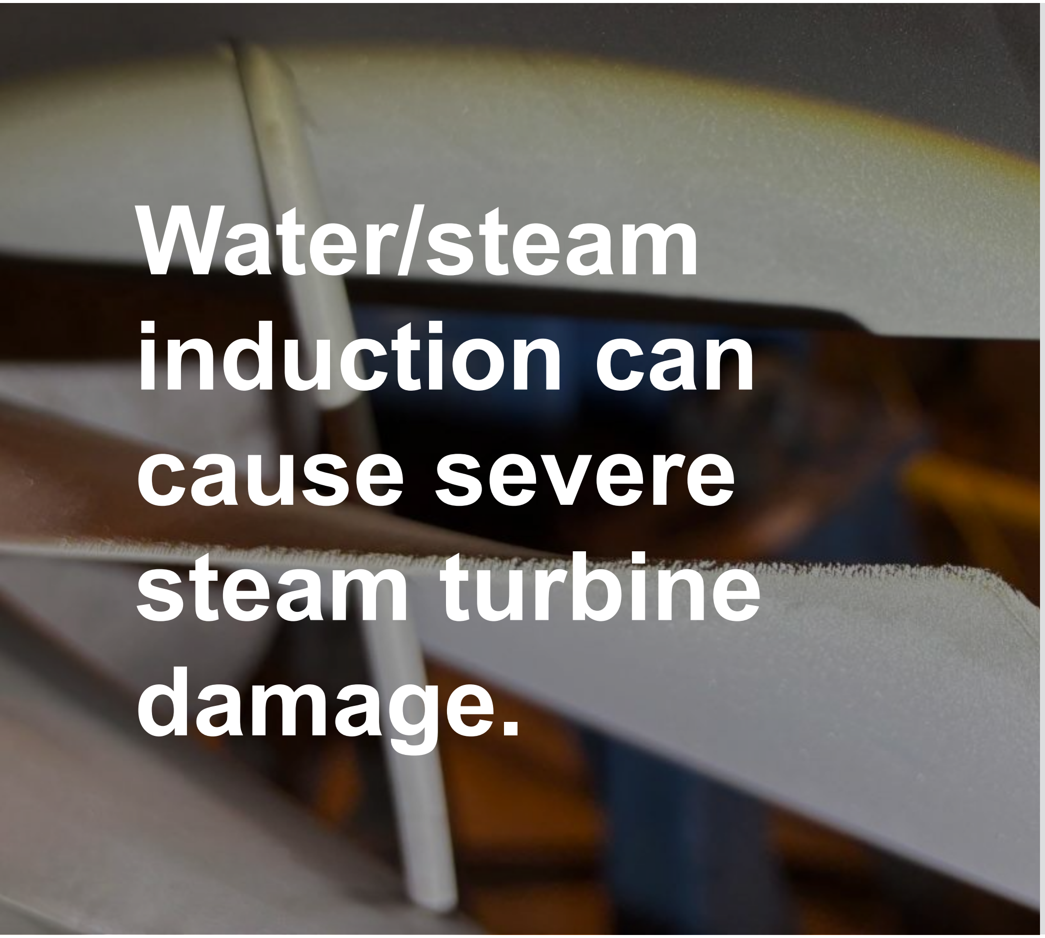
System & Operational Analysis

- Vibration Review
- Thermal/Mechanical Loading
- Steam Path Performance
- Chemistry Program Audit

ST Blade Failure Diagram

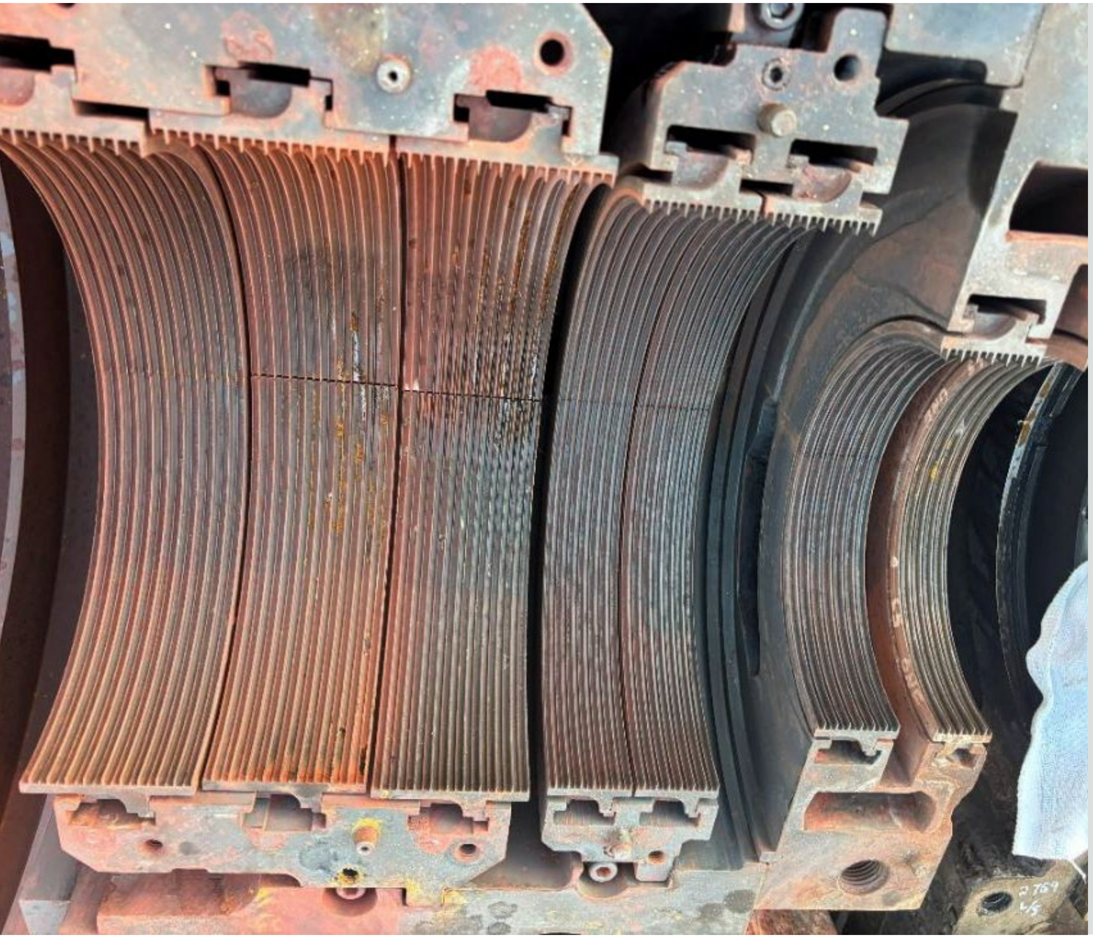


ST Water Induction Prevention Review



- **During operation** - induction increases nozzle and bucket vibration, raising failure risk.
- **During startup** - induction can distort the rotor, causing seal rubs and blade damage.
- **During shutdown** - induction can lead to destructive turbine overspeed.

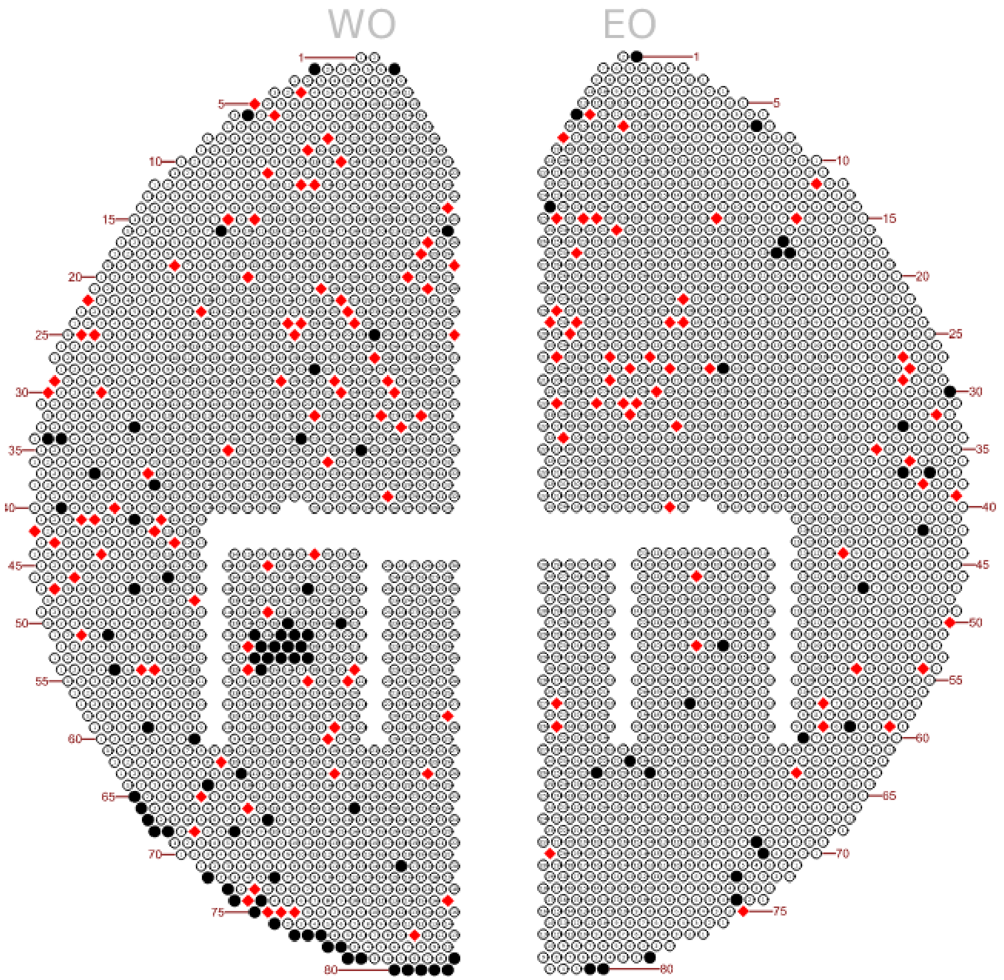
Systems that Contribute to Water Induction



- Motive steam systems
- Steam attemperation systems
- Turbine extraction/admission systems
- Feedwater heaters
- Turbine drain system
- Turbine steam seal system
- Start-up systems
- Condenser steam and water dumps
- Steam generator sources

Condenser Status

- Total tubes: 3750
- Material: Adm. Brass
- Tubes plugged: 241, 6.4%
- Tubes remaining with >70% wall thickness loss: 335
- Recommended max tubes plugged: 10%, 375
- Near EOL, new tubes/tube sheet required soon



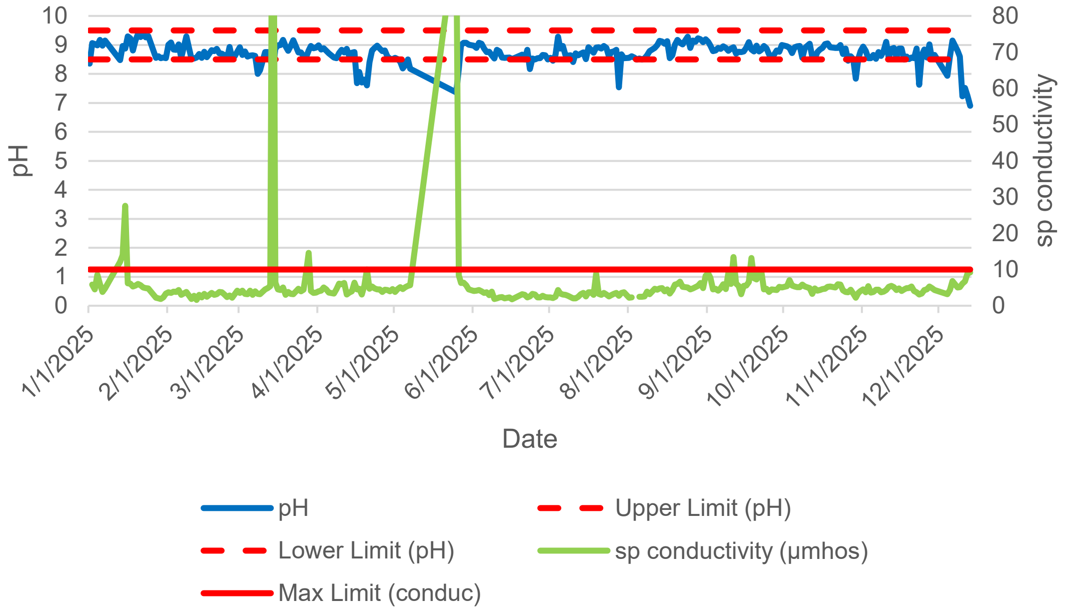
Deposit Analysis
Blades 2, 6, 10

- Elemental composition predominately oxide corrosion products.
- Main source of deposits is likely corrosion and transport of iron-containing materials from steam/water cycle.
- Deposition of entrained particulate matter; carryover of fine solids.
- High presence of aluminum is odd (e.g., possible external source of fly ash particles, aluminosilicate dust, silicate carryover from water treatment contamination).
- Chloride levels promote pitting corrosion; increased SCC risk, contribute to under-deposit corrosion.

Table A
Deposit Analysis, Wt. %

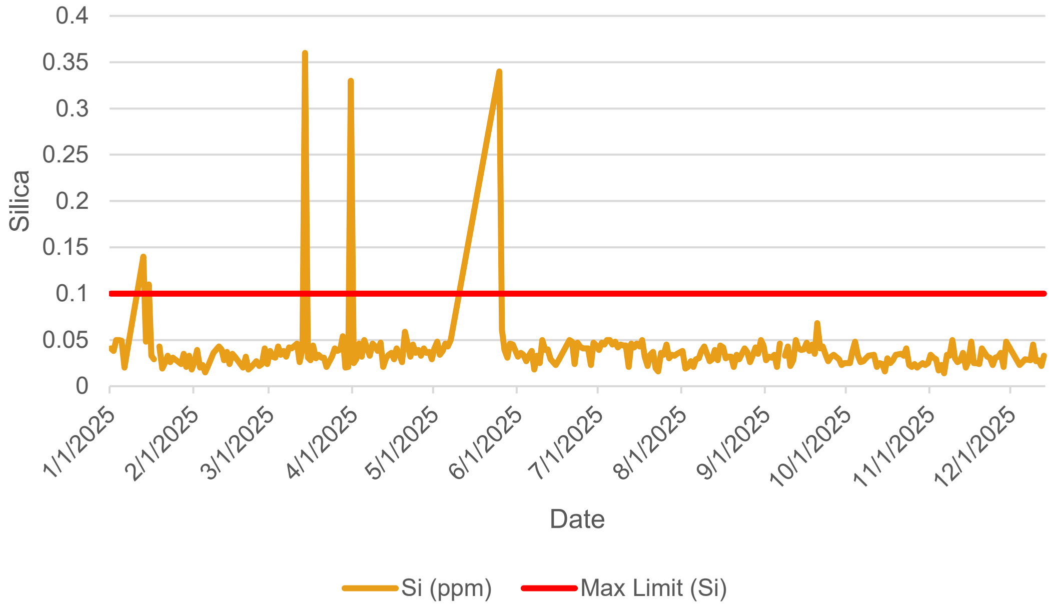
Element	Blade 2 Sample	Blade 6 Sample	Blade 10 Sample
Iron	73.71	66.45	46.54
Oxygen	12.81	14.31	19.61
Aluminum	2.88	2.53	16.77
Calcium	1.92	1.60	0.65
Silicon	1.68	2.09	9.00
Chromium	1.46	4.25	1.43
Sulfur	0.78	0.27	0.13
Nickel	0.76	0.20	0.22
Molybdenum	0.69	0.36	-
Sodium	0.66	0.94	0.29
Manganese	0.49	0.48	0.27
Magnesium	0.45	0.44	0.96
Copper	0.42	0.42	0.23
Phosphorus	0.37	0.25	0.30
Zinc	0.27	0.35	0.55
Titanium	0.25	0.20	1.39
Vanadium	0.21	0.12	-
Potassium	0.19	0.64	0.21
Chlorine	-	4.11	1.44

Unit 1 Feedwater Data Analysis



Feedwater 1: pH & Conductivity vs Time (2025)

- At least 4 condenser leaks, likely more, pH shows 7
- May 2025 had serious contamination breach



Feedwater 1: Silica vs Time (2025)

- Feedwater sp conductivity can be suppressed, cation conductivity is more sensitive
- pH can be used to correlate condenser leaks that sp conductivity cannot

Mechanisms & Root Causes of ST Blade Failures

Operators are often advised that failures are a product of LCF, HCF, SCC, etc. They are left to relate these damage mechanisms to the operational counterpart or source on the turbine.

Table 2-2
Mechanisms and Root Causes of Steam Turbine Blade Failures

Turbine	Stage	Principal Mechanism	Root Cause	Ref [1]	Ref [2]
All	All	LCF	Start-stop cycling of unit	V2, 20-1 V2, 21-1	V1, Section 1
All	All	HCF	Synchronous vibration		V1, Section 5
LP	L-0,-1	HCF	Asynchronous vibration (flutter)		
LP	L-0	HCF	System torsional resonance		
LP	Wet	Stress corrosion cracking (SCC)	Chemistry and steady stress	V2, 26-1	V1, Section 6
LP	Wet	Corrosion-assisted fatigue (CAF)	Chemistry and dynamic stress	V2, 24-1	
LP	Wet	Water droplet erosion (WDE)	Excessive moisture	V2, 27-1	V1, Section 3
HP, IP	All[(a)]	High-temperature creep (HTC)	Temperature and steady stress	V2, 16-1	V1, Section 4
HP, IP	All[(a)]	Thermal mechanical fatigue (TMF)	Thermal excursions		V1, Section 5
HP, IP	Initial	Solid particle erosion (SPE)	Steam quality and treatment	V2, 17-1	V1, Section 4
HP	Row 1	HCF	Partial arc steam admission	V2, 21:2	V1, Section 5
All	All	Overload	Overspeed, transient events	V2, 32-1	V1, Section 7
All	All	Deformation	Axial/radial rubs	V2, 32-1	V1, Section 7
All	All	High energy impact	Foreign objects, water	V2, 28-1	V2, Section 9

[1] *Turbine Steam Path Damage: Theory and Practice, Volume 2* [2].
[2] W. Sanders, *Turbine Steam Path, Volume 1: Turbine Steam Path Maintenance and Repair* [3].
[(a)] Rows that operate at temperatures >900°F (482°C).

Source: EPRI Steam Turbine Blade Failure Root Cause Analysis Guide, 2008.

D.F French Fractography Results

- Primary failure initiated in Blades 188 and 208 due to high-cycle fatigue (HCF).
- Secondary impact damage identified on Blades 1-4 and 60.
- No evidence of stress-corrosion cracking (SCC) or corrosion fatigue.
- Blade vibration and dovetail fretting indicate vibration-driven fatigue mechanism.
- Deposits and steam contamination likely increased blade imbalance and vibrational stress.
- Corrosion and pitting contributed, but not primary failure cause.
- Deposits likely reduced efficiency and increased vibration through flow disruption.

Batch 1 - Four blade samples
- Stage 11 Blade #1
- Stage 11 Blade #2
- Stage 11 Blade #3
- Stage 11 Blade #4

Batch 2 – Eight blade samples & three deposit samples
- Stage 11 Blade #36
- **Stage 12 Blade #60**
- Stage 11 Blade #143
- Stage 11 Blade #145
- Stage 12 Blade #158
- Stage 11 Blade #167
- **Stage 11 Blade #188**
- **Stage 11 Blade #208**
- **Blade 2 Corrosion Sample**
- **Blade 6 Corrosion Sample**

Stage 11 – Blade #188 & #208

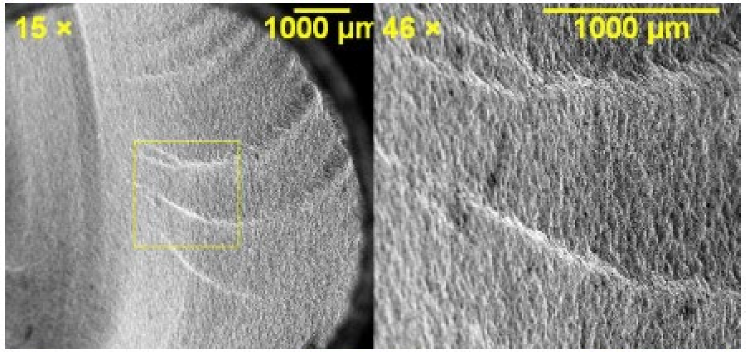


Figure 28. Beach marks, Blade #188, SEM image

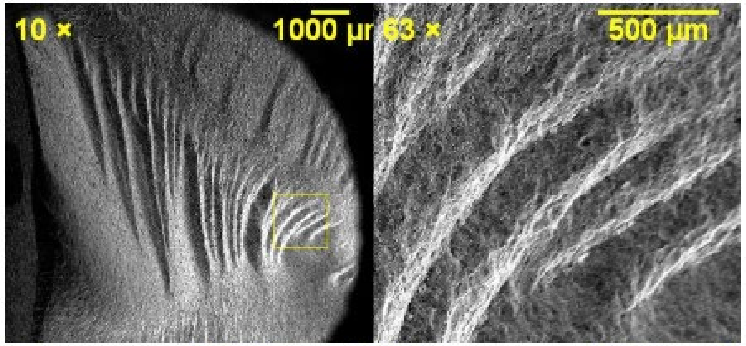


Figure 29. Beach marks, Blade #208, SEM image

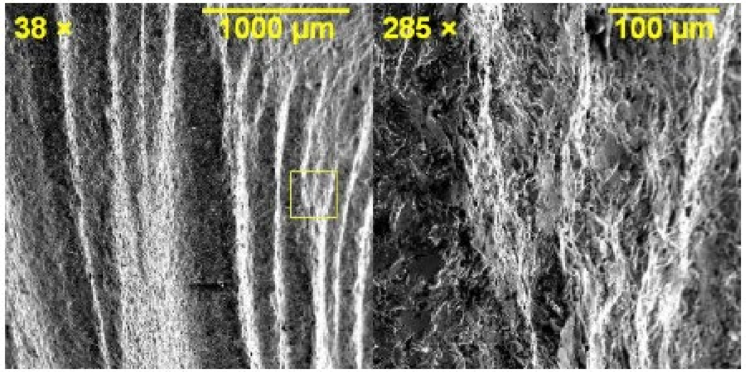


Figure 30. Beach marks, Blade #208, SEM image

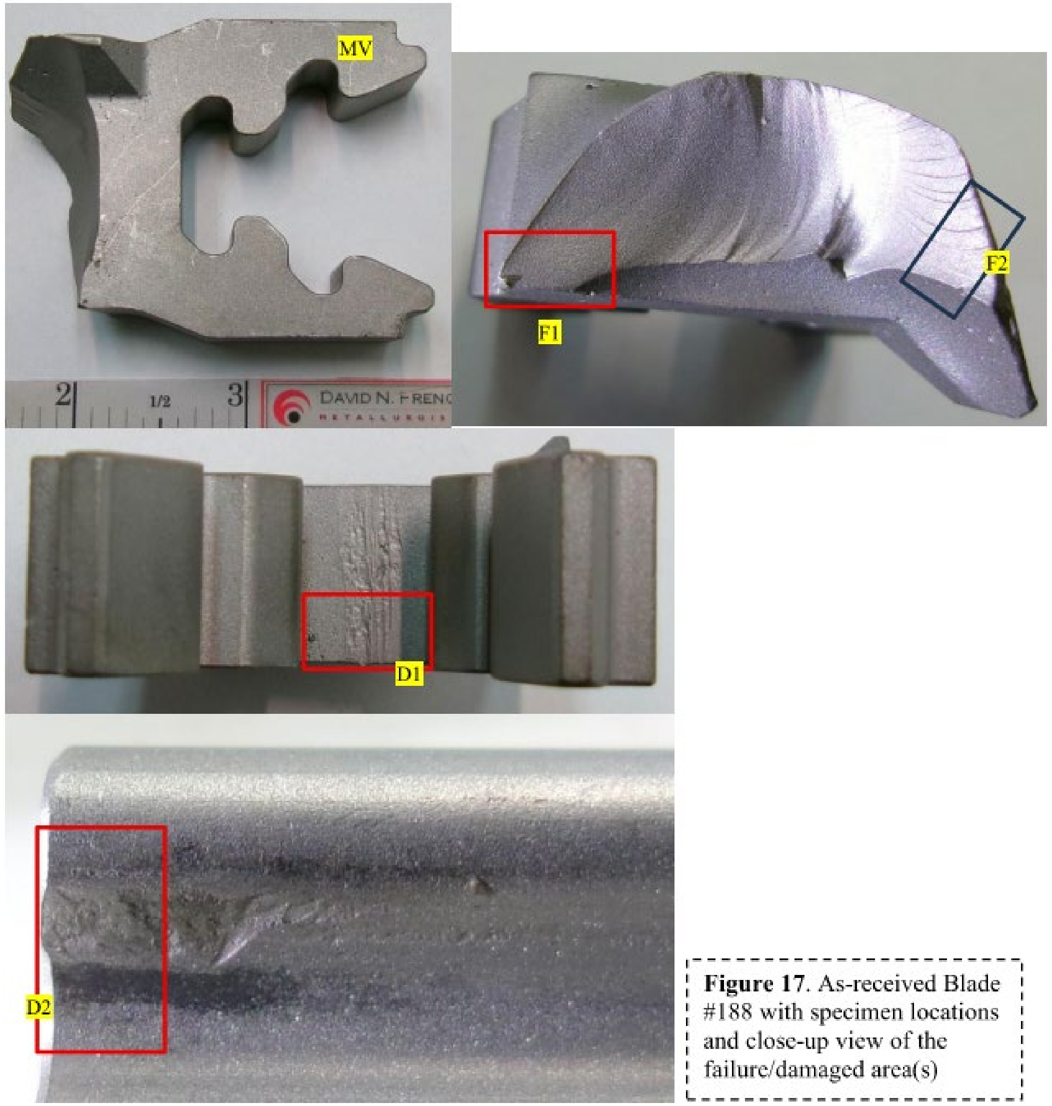


Figure 17. As-received Blade #188 with specimen locations and close-up view of the failure/damaged area(s)

Recommendations from Metallurgist

01 **Perform vibration testing and rotor balance assessment** to identify and correct sources of blade dynamic instability.

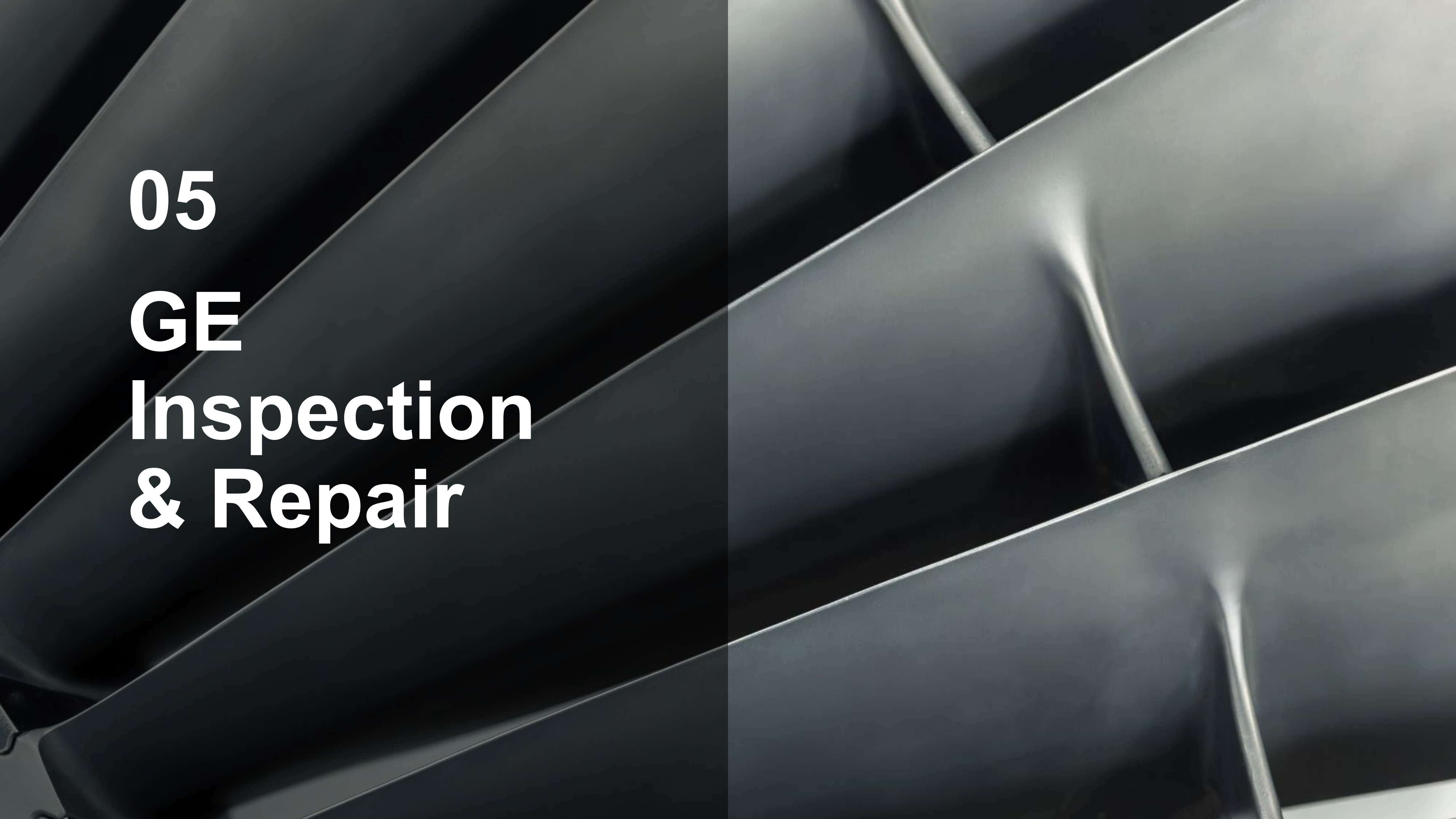
02 **Inspect remaining blades** using visual and NDE methods to identify fatigue cracking and replace damaged components as needed.

03 **Verify blade material properties and heat-treatment adequacy** for operating conditions.

04 **Identify and eliminate sources of steam contamination and carryover,** including attemperator and condenser-related ingress.

05 **Improve steam purity and implement routine turbine cleaning and inspection** to minimize deposit buildup and imbalance.

06 **Replace blades with significant pitting damage** due to increased fatigue crack initiation risk.



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GE Inspection & Repair

Current Turbine Status

01

Rotor buckets on stages 11 and 12 were fully replaced.

02

Stationary components were repaired.

03

Contractor re-mobilized with the rotor back in the machine.

04

GE (OEM) brought in to inspect and decide next steps for reliable and safe operation.

05

GE concluded rotor and stationary components needed further evaluation at their shops.

06

Current Timeline:

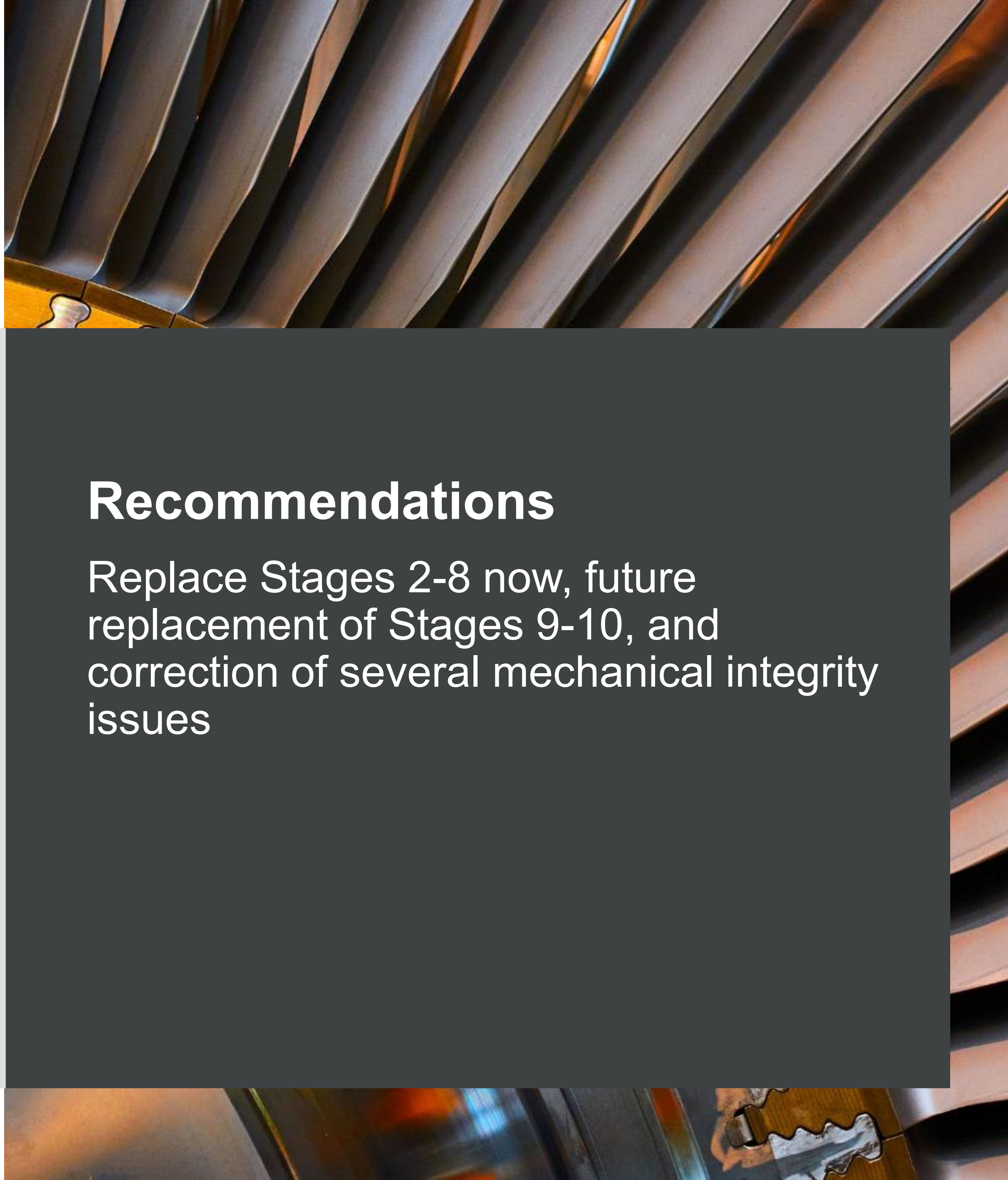
Rotor stages (varies) return Oct-Nov 2026.

Diaphragms to ship Oct 2026.

GE Evaluation – Rotor

Key Findings

- Widespread degradation - severe pitting, erosion, rubbing, localized FOD. Most significant damage in Stages 2-8.
- Admission side erosion on stages 5-8, indicating prolonged exposure to contaminated or erosive steam conditions
- Stages 3 and 4 exhibited FOD in addition to severe pitting
- Several stages exhibited opened notches, lack of tenon engagement and rubbing conditions
- Rotor journals and coupling dimensions were generally within acceptable limits; no cracking indications



Recommendations

Replace Stages 2-8 now, future replacement of Stages 9-10, and correction of several mechanical integrity issues

GE Rotor Photos

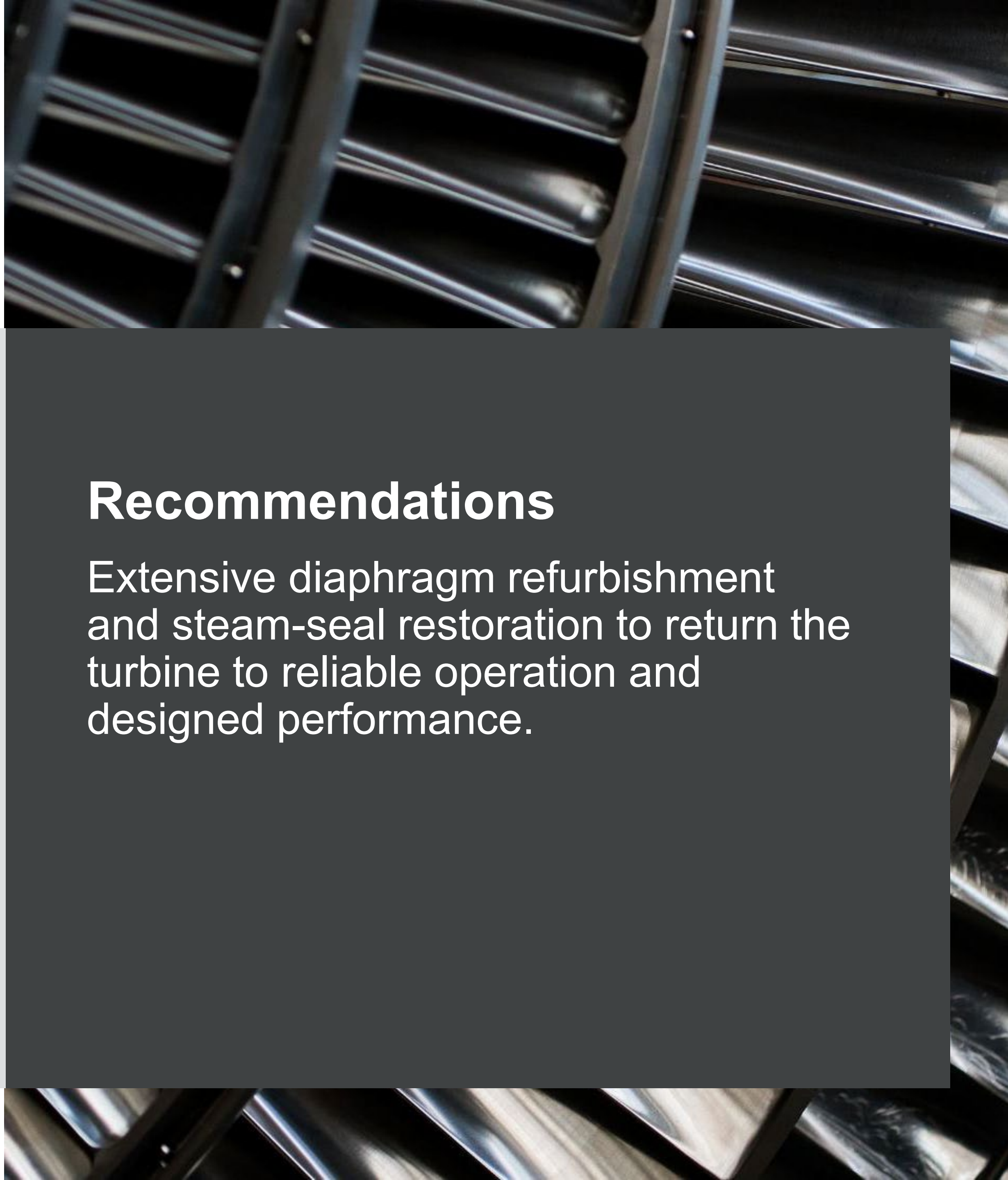
Stage 8 Buckets/Tenons – Heavy Pitting/Erosion

Stage 11 (New) Tenons – High, Chamfer Visible; several blade edges dented

GE Evaluation – Stationary Components

Key Findings

- Widespread deterioration throughout diaphragm set.
- Major diaphragm restoration required on Stages 2, 3 and 7-12 to recover steam-path geometry and efficiency.
- Damage pattern consistent with long-term erosion, deposit-related wear and steam-path degradation.
- Numerous diaphragms exhibited damaged spill strips, worn center slots, dowel fit-up issues and leveling screw deficiencies.
- Minor partition repair w/ INCO; major partition repair using 410SS.



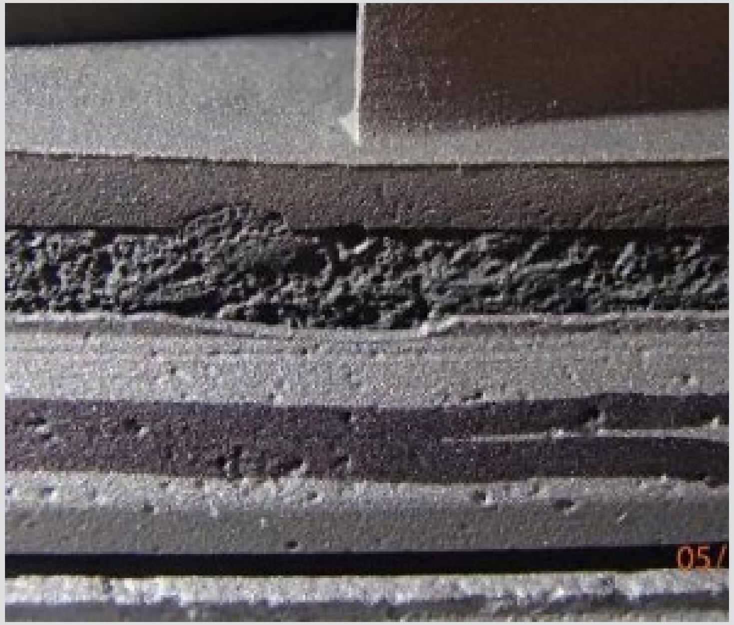
Recommendations

Extensive diaphragm refurbishment and steam-seal restoration to return the turbine to reliable operation and designed performance.

GE Diaphragm Photos

Stage 10 LH Pinhole in Partition Trailing Edge

Stage 9 LH Pinholes in Partitions



Stage 4 UH Erosion and Rub on Spill Strips

06
Conclusions

Conclusions

- Initial failure occurred in Stage 11 blades #188 and #208.
- Dominant mechanism was vibration-induced high cycle fatigue.
- Corrosion and pitting were contributors, but not the root cause.
- No evidence of SCC or corrosion-fatigue failure.
- Steam contamination and deposits likely aggregated the vibration problem.
- Multiple condenser leaks, steam purity excursions and contamination incidents, evidence of widespread deposits and corrosion throughout steam path.
- Additional effects from water induction are under investigation (e.g., faulty steam traps).
- **Root cause investigation is ongoing.**

Questions?

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