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OPERATOR EXPERIENCE WITH NON-GAS PATH POWER TURBINE DISC CORROSION AS AN EMERGENT EQUIPMENT INTEGRITY THREAT

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Abstract

TransCanada operate a large fleet of gas turbine driven equipment, with more than 400 units in service in both Pipeline Compression and Power Generation Service. These include a mix of both aero-derivative and industrial frame machines. Large portions of this portfolio have been in service for significant time, such that this aging fleet has encroached into original design lives of some components. TransCanada has historically been proactive in the investigation and adoption of several life extension concepts such as HP Turbine blade rejuvenation and advanced weld repairs from expert vendors that have allowed significant life cycle savings. To counter this aging fleet issue, TransCanada has also explored power turbine disc remaining-life and prognostic life extension strategies. Outcomes of some these efforts, coupled with recent experience and findings have revealed certain threats that were unanticipated given the general duty of the bulk of its compression equipment in the North American theatre.

This paper aims to discuss the emergence of a corrosion threat within TransCanada's system that is manifest in under-platform and non-gas path areas of hot end components. In particular, it offers some characterisation of the nature of the corrosion itself on power turbine discs, some cases of which have cascaded into significant integrity threats. In turn, it also discusses possible contributory roles of an inventory of contaminant sources (air, fuel and build) as well as their observed migration and deposition mechanisms. An important distinction is that these cases, which bear several hallmarks of sulphidation processes, occur in machines whose gas path components otherwise do not exhibit traditional hot corrosion damage normally attributed with exposure to combustion gases bearing products formed from contaminants in the fuel and air. In some areas, the temperature environments in question were also originally considered to be inadequate for such processes to occur and some of these aspects are reviewed.

Some of the strategies TransCanada have employed to help mitigate this threat are offered as will plans moving forward to further characterise the nature of the processes and understand relative susceptibility of the family disc alloys employed in its fleet. Finally, lessons learned and implications for life extension strategies are provided from the TransCanada perspective.

1 Introduction

In the past two and a half years, TransCanada have had three power turbine disc findings involving cracks near torque-transmission features or low in the web. Two of these cases featured cracks of significant length that represented major integrity threats but were fortunately identified prior to failure and material release. In each case, these flaws appeared on the forward side of 2nd stage discs in rotors that had been previously overhauled and had service lives between 110K and 146K hours. In each case, no mechanical property, chemistry or inherent metallurgical (processing-hardness, microstructure) anomalies were identified in the forgings.

Although some interest had already been raised within TCPL in respect to disc – blade contact issues (as early as 2001), subsequent to these cracking cases enhanced inspection opportunity and diligence have found increasing frequency of corrosion issues. In many cases, these have been deemed sufficient to preclude further operation of these expensive components. Indeed, root causes of the disc cracking have eventually and coincidentally found that corrosion featured in the crack initiations or propagation. It should be noted that in none of these cases were actual gas-path airfoil surfaces identified to feature symptoms of hot corrosion.

Further investigation into the sources of reactive contaminants has yielded some findings that were initially unexpected for the operating theatres of machines in question. They also speak to aspects of assembly and field installation of this equipment as well as the selection and maintenance of inlet and filtration systems.

The purpose of this article is not to present the full detail of root cause investigations or to suggest fault. Rather, it is to present the general findings (with sufficient substantiation) and to raise some awareness as to the seemingly wider prevalence of these corrosion risks than previously appreciated, certainly within TransCanada. It is intended to discuss lessons learned and mitigation strategies to alleviate concern in the hope that these may be useful for the wider community.

2 Observed Corrosion Issues

Over the past several of years, disc corrosion issues have presented themselves more frequently during overhauls. These have occurred in three general regions, namely at the blade attachment posts (both loaded contact serration faces and on gas washed end faces), disc webs, and in the vicinity of highly-stressed torque transmission features near the hub of the discs. Examples are provided in the following.

2.1 Disc Rim and Post Serrations

Depicted in Figure 1(A) are the contact lands of a blade attachment post, featuring a very tenacious, heavy grey-black scale deposit. Such scales have been investigated and have been found in some cases to show elevated molybdenum and sulphur in the scale, with products extending above the original surface some 27 um with a total reaction zone of 50 um. [1]

In other cases, scales have featured Sodium, Magnesium Calcium and Silicon, Cobalt, in addition to Sulphur and occasionally phosphorous. A hypothesis here involves foreign contaminants, from the environment and possibly remnant glass bead fines, play a role in forming a slag. It is suggested Cobalt may be a product of corrosion of the airfoil material that has transferred due to fretting action. Extreme cases found the thickness of the scale to be 114 um. [2]

Indeed, analysis of blade serration contact surfaces has revealed pitting with features typical of hot corrosion with sulphidation of underlying base alloy, under the pit and penetrating as far as 50 um along grain boundaries. Pit depths were as large as 100 um. It was specifically evaluated and found that the same blade airfoil showed typical of oxidation with no evidence of base alloy sulphidation. [3]

Figure 2 depicts a situation where sulfides have clearly found there way to a denuded area of a disc post base alloy. [4]

The resultant surface inconsistencies described above on highly stressed serration contacts necessitate that an engineered approach involving the OEM be applied in consideration of the effects. TransCanada has retired discs and blades from service on this issue. Fatigue Fretting, concentrated by such surface conditions, becomes a concern borne out of this corrosion and has caused blade and/or post releases. [5]

Of particular note in Figure 1(C) is the apparent extreme difference in resistance to corrosion between the rotor blade root (Rene 80) and the disc material (I901) even in similar thermal environments. Given the above, the post face and non-contact areas are considered subject to a different mechanism that is yet being investigated.

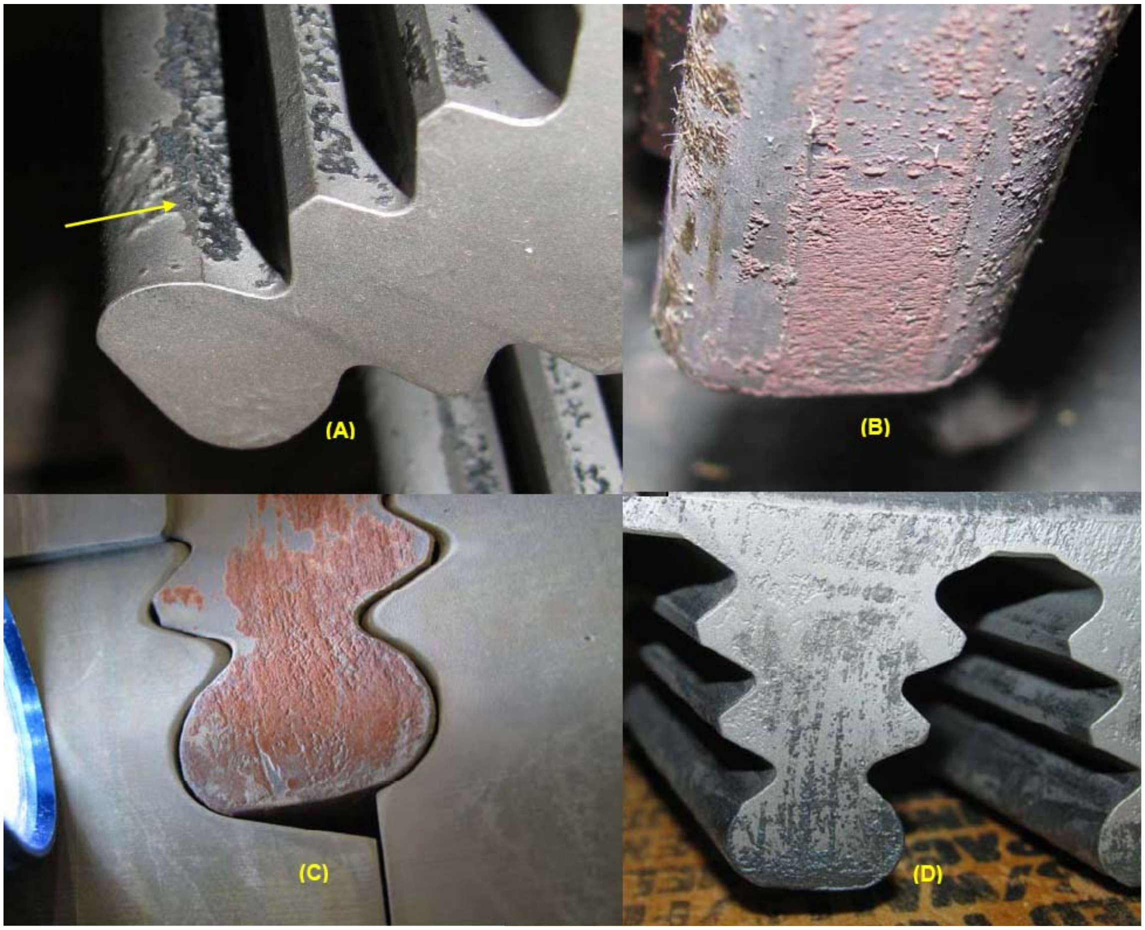


Figure 1: Example post conditions; A – Scale on serrations loaded surface (A-286); B – Scale on Post unloaded top face (I901); C – Post End face corrosion (I901); D – Identical disc (I901) after cleaning;

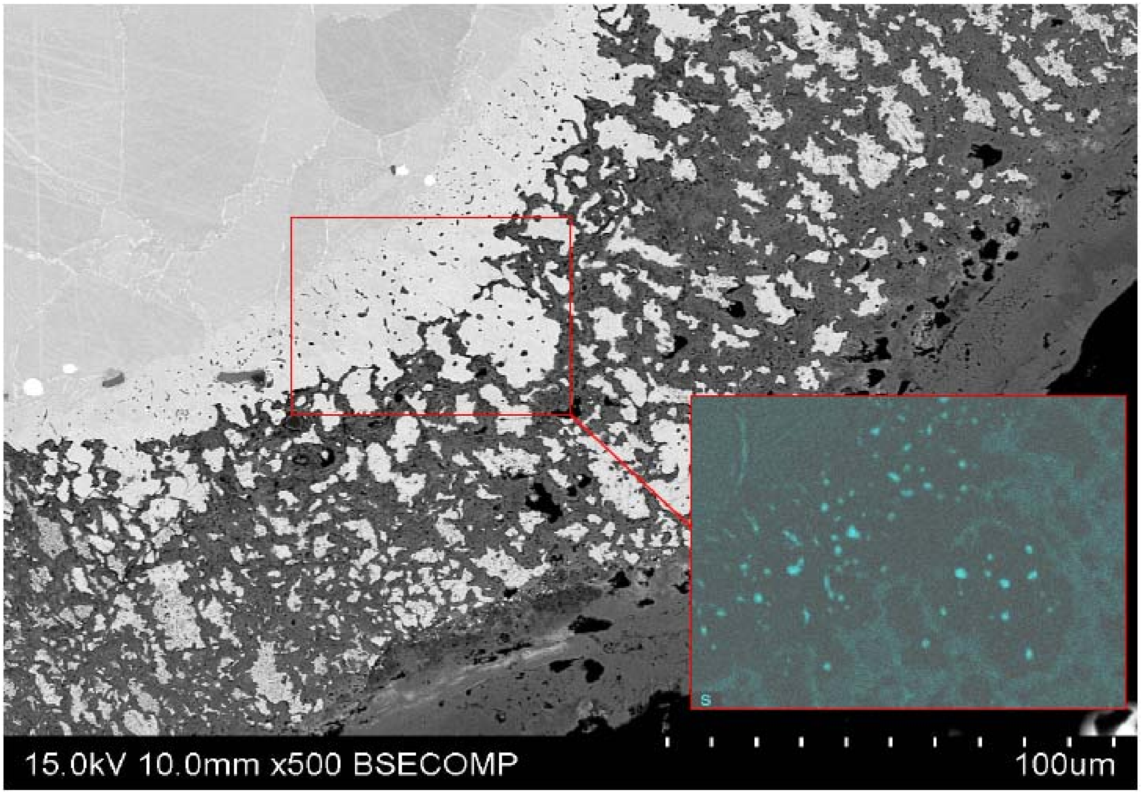


Figure 2: Sample corrosion on a post loaded serration (similar to Figure 1 (A)), featuring sulfide particles in a denuded zone under the scale. SEM Images courtesy G. White – RRRESI Materials Lab. [4]

It is accepted that disc blade retention features and under platform have occasionally been subject to corrosion and sulphidation, but more often in a marine environment or on flight engines where sulfur is borne in the fuel and sea water. [6, 7] However, it is appreciated that some OEM's have begun to observe pitting of aero turbine discs and components outside the combustion gas path and seek novel solutions in the form of strain tolerant coatings and ductile coatings with fatigue and corrosion resistance specifically for application to discs. [8,9] Others have claimed successful application of a chromised coating of Waspalloy discs for FCC expanders for duty in environments where partial pressure of oxygen is extremely low. [10]

2.2 Disc Web

Disc Web regions have also been found to feature scales and pitting. In some cases, these are uniform, occasionally they feature random patched patterns, in some cases are correlated with streaks to disc features and in yet other cases, they bear features of contact with foreign contaminants. Figure 3 depicts several such examples.

While the characterization of such attack and pitting is an ongoing project, it certainly bears noting that effects of similar pitting, albeit conclusively hot corrosion attributed, on disk material durability has recently been studied with a finding that such features can reduce fatigue life by 60 to 98%. [11]

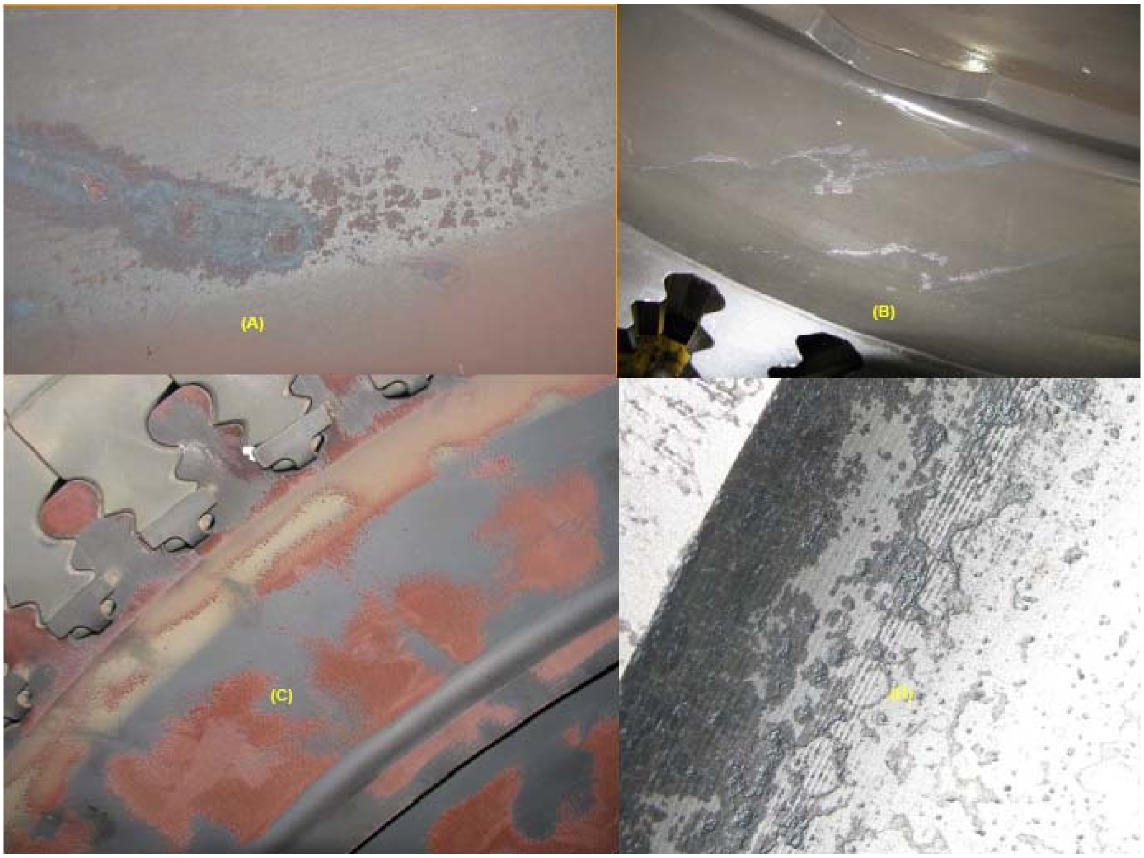


Figure 3: A – Corrosion and pitting near a drip like deposit on a web (A-286), B – localized scaled drip like deposit (I901), C – Patchy corrosion areas that extend above original surface (I901) D – Same disc as C after cleaning.

2.3 Disc Torque Transmission Areas

TransCanada have recently experienced three cracked discs where sulphidation has been identified at the initiation or has played a role in propagation.

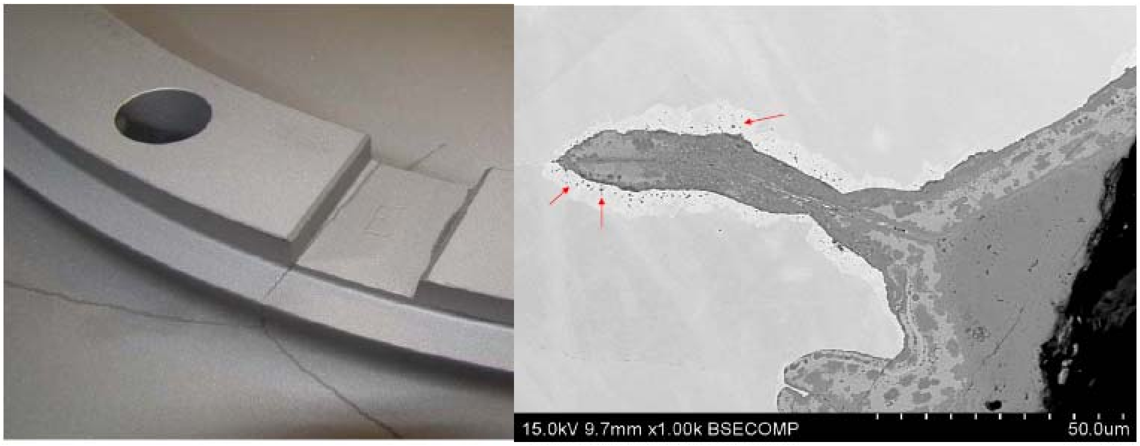


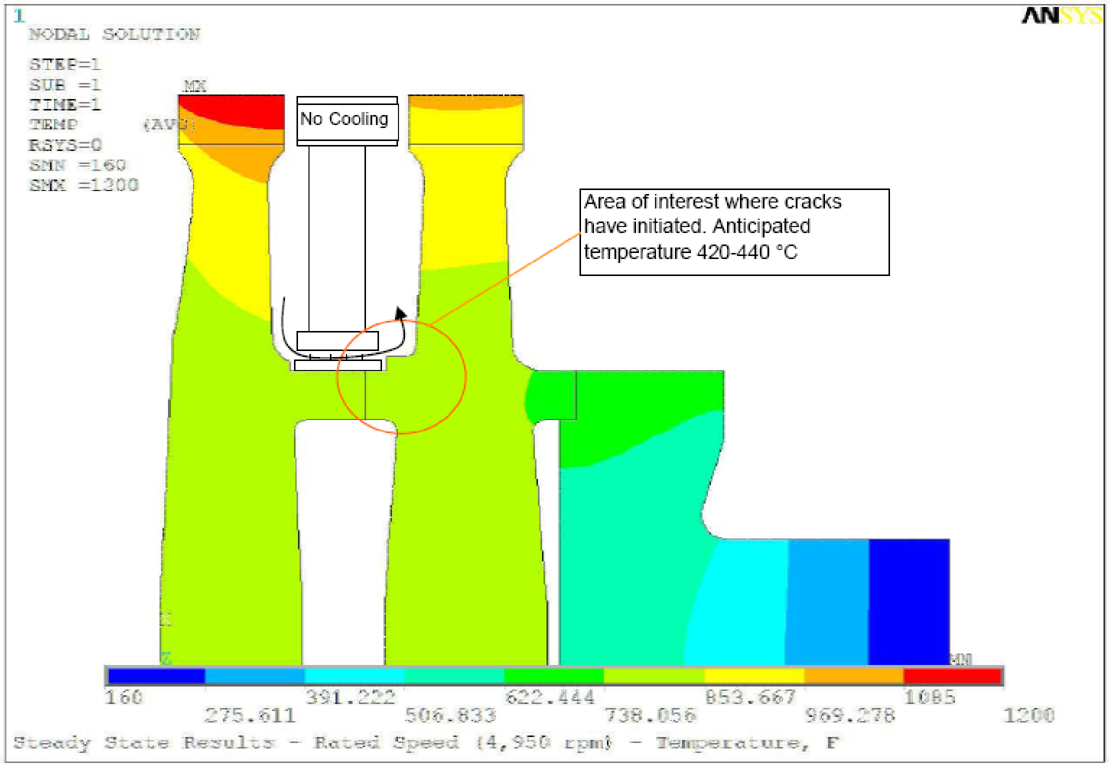
Figure 4: A crack at a torque transmission feature and a corrosion spike identified near the origin, featuring a chromium depleted area and sulphides (identified by red arrows) under thick scale. SEM Image courtesy G. White – RRESI Materials Lab. [12]

3 Corrosion Considerations

A multitude of texts and resources describe the defining characteristics, underlying chemistry and propagation of hot corrosion. [13, 14, 15] The intent here is not to repeat these details other than to point out that in general, the process requires the formation and deposition of salts (such as sodium sulphate Na_2SO_4) and the proper thermal environment to support the reactions needed. In general, a molten sulphate is needed to react with and damage protective surface oxides on the material, after which further damage and reaction with the alloy can proceed. The generally understood temperature ranges for superalloy hot corrosion (which do vary from source to source) are regarded as 650-816 °C for Low Temperature Hot Corrosion (LTHC or Type II) and 871-1093 °C for High Temperature (HTHC or Type I). LTHC and HTHC are differentiated by their propagation modes and chemistry (acidic versus basic fluxing) involved in the breakdown of oxides and alloy. [13] LTHC also requires a relatively high partial pressure of SO_3 and a mixed-mode has also been described.

3.1 Thermal Environment

As such, we are left with a first dilemma in that it is difficult to rationalize the sulphidation observed (examples above) when the power turbine discs (with the exception of the outer blade-attachment of a first stage disc) should not reasonably encounter the necessary temperature ranges for these supporting reactions. Figure 5 offers salient results of a third party commissioned thermal analysis for one of the types of equipment affected.



Area of interest where cracks have initiated. Anticipated temperature 420-440 °C

Figure 5: RT56 Steady State Thermal Analysis for rated Condition. [16]

In reality, the temperature ranges inferred above for LTHC and HTHC are actually somewhat variable and fluid owing to the upper end being fixed by the dew point of the corrosive species which depends on the impurities in the flue gas. The lower limit is defined by the lowest eutectic melt that can be formed depending on the composition of the deposits and the material of the components. [15] Hence, determining contaminants that are in play is paramount to developing and understanding of the true range.

In addition, the presence of the liquid sulphate medium is categorised as important in respect to corrosion rates because transport of reactants and products of the corrosion reaction is much more rapid in a liquid than for a solid state reaction. Rapid transport is a key aspect of corrosion rates that can be catastrophic. However, even if a salt deposit freezes on the component surfaces, reactions with existing oxide scales can reduce the melting point of the deposit by hundreds of degrees, which can set the stage for corrosion at lower component temperatures. [17] In this context, it is to be recalled that the power turbine equipment in question has in many cases been installed for 50000 to100000 hours without removal for inspection. Hence, rates in the observed power turbine cases may indeed be much slower than the more obvious catastrophic rates that merit attention in the gas path components.

3.2 The Role of Alloy Composition

Yet another consideration is that in respect to superalloy hot corrosion, the bulk of research and publication has centered on those components and materials that are in the hot gas path, which are in turn dominated by nickel-based and to a lesser extent cobalt-based alloys. The importance of the specifics of the base alloy's chemistry can be lost without appreciating the above. In some cases, disc alloys more resemble true nickel-based superalloys but in others, they are actually Iron-Nickel austenitic precipitation hardened alloys or even martensitic high-temperature steels in some designs. Table 1 provides a listing of some common turbine disc alloys that are of interest in respect to TCPL's fleet.

Table 1: Common Disc Alloys in Power Turbines and Combustion Turbines

Composition (%)											
Alloy	Cr	Ni	Co	Mo	Nb	Ti	Al	Fe	C	V	Mn
Waspalloy	19.50	57.0	13.5	4.30	-	3.0	1.4	<2.0	0.07	-	-
IN718	19.00	52.5	-	3.00	5.1	0.9	0.5	18.5	0.08	-	-
I901	12.50	42.5	-	6.00	-	2.7	-	36.2	0.10	-	-
A-286	15.00	26.0	-	1.25	-	2.0	0.2	55.2	0.04	-	-
M152	12.00	2.5	-	1.75	-	-	-	83.3	0.15	0.35	-
FV535	10.50	0.5	5.0	0.70	-	-	-	82.1	0.10	0.20	0.90

In respect to general findings from available literature, an accepted rule of thumb is that chromia formation is beneficial in respect to corrosion protection in part due to the higher basicity of its solubility minima in fused Na_2SO_4. [15] Hence from a comparison perspective, chrome and aluminum content should help provide corrosion resistance. However, investigations have studied the synergistic dissolution of basic oxide Fe_2O_3 and acidic oxide Cr_2O_3 and have measured higher rates of dissolution when both oxides are present. [15] Hence, this may have a meaningful bearing on the susceptibility of some of the Iron base and specialty steel materials relative their nickel-base counterparts. This has been demonstrated in a test program that showed that a mixed oxide yielded accelerated kinetics via synergistic reaction and that when chlorines were present, Ni-Based alloys performed better than Fe-based materials. [18]

Some older research conducted on nickel-base superalloys in the 1970's also reported, via assessments of scale layering, that samples which underwent hot corrosions showed the presence of a $(Ni,Co)MoO_4$ layer near the alloy oxide interface. It was taken from these results that molybdenum in an alloy is detrimental whereas conversely, Tantalum, which appeared in oxide scales on specimens that survived, was deemed beneficial. [19] Today, refractory elements (Mo, W and V) are reported to have the potential for alloy-induced acidic fluxing where their formed oxides cause Na_2SO_4 to become acidic such that when these coexist they can lead to self sustaining corrosion. [15, 18] It has also been found that for Nickel-Base alloys the detrimental effects of Mo on corrosion resistance has also been documented in test programs related to advanced materials for Ultra-Supercritical Coal Fired power plants. [20]

3.3 Effects of Additional Contaminates

There are some effects of other impurities that need to be considered in respect to sulphidation, especially when one is considering the additional territory of Iron-Nickel and Specialty Steels within the spectrum of materials of interest. Superheater surfaces have been documented to corrode due to alkali iron-trisulphates at temperatures as low as 399 – 482 °C, although this requires reducing atmospheres with low oxygen levels. [7]

- Chlorides – in early studies chlorides were suspected of causing accelerated hot corrosion in marine environments. This can be attributed to the fact the melt point of Na_2SO_4 can be reduced from 884 °C to 790 °C for a Na_2SO_4-NaCl deposit. [15] Others have observed the effect down to 620 °C. [63]
- Potassium – Although less studied, Potassium Sulphate (K_2SO_4) can act as the principle salt for the corrosion reactions. However, in a similar fashion, when forming a eutectic with Na_2SO_4, the deposit melting point drops to 831 °C. [15] Further, when NaCl is factored in, the melting points can be further depressed depending on the concentrations to temperatures as low as 550°C. [21]
- Zinc – In Waste to Energy boilers, Zinc Sulphate salts have proven to be problematic and have melting points when present (but dominant) with other alkali salts that can be below 425 °C. When combined with chlorides, hot corrosion attack has been reported as low as 200 °C. [15, 22] Zinc in itself can pose a problem on its own in that its low melting point of 420 °C facilitates LME in some austenitic stainless steels and nickel alloys. [23]
- Carbon deposits have been reported as an accelerating agent for the hot corrosion process by making sulphate deposits more basic. [7]
- Phosphorous and Lead: A study aimed at automotive applications with Nimonic 115 documented nickel containing alloys, the presence of phosphate salts such as lead phosphate or sodium phosphate, in combination with Na_2SO_4 resulted in accelerated and heavy corrosion. It was also shown that a lead-phosphate/lead-sulphate mixture is also detrimental. [24]

- Calcium: Calcium Sulphate ($CaSO_4$ – Anhydrite) can also act as the salt in the corrosion reactions. It too has been studied in corrosion experiments at 850 °C with carbon deposits employed to enhance activity. It was found that in such circumstances, replicating fluidised bed combustors, hot corrosion was found to occur at levels that replicated field findings. [25]

Table 2 provides a summary of possible salts and mixtures of potential interest on natural gas fired equipment (no vanadium), dependant on contaminants that enter the system and form deposits.

Table 2: Melting Point of Possible Corrosive Deposits [15, 22, 26]

Salt	Compound	Melting Point (°C)
Halite	NaCl	800
Aluminum Sulphate	Al2(SO4)3	771
Calcium Sulphate	CaSO4	1449
Ferric Oxide	Fe2O3	1566
Ferric Sulphate	Fe2(SO4)3	480
Nickel Sulphate	NiSO4	841
Sodium Sulphate	Na2SO4	884
Mixture	Na2SO4 - NaCl	790
Sodium BiSulphate	NaHSO4	249
Sodium Pyrosulphate	Na2S2O7	399
Sodium Ferric Sulphate	Na3Fe(SO4)3	538
Potassium Pyrosulphate	K2S2O7	325
Potassium Sulphate	K2SO4	1069
Zinc Sulphate	ZnSO4	680
Mixture	K2SO4-Na2SO4	831
Mixture	K2SO4-Na2SO4-ZnSO4	350
Mixture	Na2SO4 - NiSO4	671
Mixture	Na2SO4 - CoSO4	565

4 Inventory of Contaminates of Interest: Sulfur and Chlorine

4.1 Fuel-Gas Borne Sulfur

Most literature regarding hot corrosion in gas turbines generally make the presumption that sulfur for these processes is borne in the fuel, while the alkali species are borne in the air supply. In this particular situation, the sulphur content of fuel is orders of magnitude lower than older, liquid (0.1% S) or marine (1% S) fuel supplies that were a concern. All of the cases of concern are fueled by pipeline quality, non-odorised natural gas. In these theaters, pipeline tariffs allow a maximum of 23 mg/m^3 (16 ppm_v) of H_2S which is included in a tariff maximum total sulphur allowable level of 115 mg/m^3 (85 ppm_v). [27] All sour receipt points are continuously monitored and shut-in when tariff levels are reached. Some US pipelines can carry double these amounts for comparison. In reality, these numbers include some margin to account for major upsets, and average numbers in the Alberta System run Total Sulphur in the 2.7 mg/m^3 (2 ppm_v) range, often made up of more carbonyl sulphide (COS) and mercaptan species than hydrogen sulphide. Historically, sustained Total Sulfur peaks can be approximately 9 ppmv (12.2 mg/m^3).

Considering a 28 MW compressor set with an efficiency near 35.9 % with a representative natural gas fuel (LHM = 48272 kJ/kg), the following represent approximate daily SO_2 values in the exhaust gas for a meaningful range of fuel Total Sulfur levels.

Table 3: Representative Fuel Borne Sulfur and Exhaust SO_2

Fuel Total Sulfur	Fuel Total Sulfur	Mass Sulfur From Fuel	Fuel Mass Fraction S	Exhaust Mass SO2
mg/m^3	ppmv	kg/day	-	kg/day
115.00	85.000	21.995	1.559E-04	43.988
12.17	9.000	2.328	1.650E-05	4.655
7.63	5.640	1.495	1.060E-05	2.991
2.70	1.996	0.516	3.660E-06	1.033

4.2 Air-Borne Sulfur

Considering the fairly meager fuel-borne sulfur levels, it is next worthy of considering air borne contaminants in the theaters of concern. Alberta is somewhat unique within Canada in this perspective owing to the relatively high oil and gas activity within the province and its relatively large proportion of coal fired generation. Despite meaningful reductions in solution gas venting and flaring in the past decade, Upstream Oil and Gas activity still represents a significant portion of emitted SO_2 within the province. These emissions come from sour gas treatment/sweetening facilities, oil and gas batteries and flaring of solution gas.

4.2.1 Sour Gas Treatment Facilities

In respect to sour gas treatment facilities, these are distributed within the province where gas fields necessitate, but usually within small distances from mainline transmission facilities where some of this equipment of concern is located. The Alberta Government has had a protracted program to reduce SO_2 emissions from these facilities for some time, with the result that new and larger facilities have had to increase the efficiency of their sulphur capture (some to over 99%). In the past three decades however, the appetite to develop sour fields has also increased, such that these facilities process more gas. The emissions from the stacks consists of oxidized un-captured H2S and is therefore mainly a moist SO_2 gas emission. Nonetheless, the output from these facilities amounts to fairly significant 120 tonnes/day in 2008, down from approximately 216 tonnes/day in 2000. [28] Some of the largest of these facilities are within close proximity to affected sites of interest (Figure 6).

These Plumes contain a high water content of approximately 25 %-mole but is emitted at a temperature in excess of 530 °C and this plume is markedly different from a coal fired plant or coker and there appears to be less opportunity to form neutral sulphates. [29] Sulphates may be formed by reaction of atmospheric SO_2 emissions with mineral dust particles such as calcium and magnesium.[30] Dispersion modeling of these plumes within the “sour gas corridor” is quite complex owing to the foothills topography of the landscape and climatology that features inversion breakdowns and plume trapping. The fate of SO_2 from these plants has been difficult to determine, but some early estimates from one sour gas plant inferred that 40% of SO_2 was returned by convective storms to the vicinity of the plant while others suggested only a few percent could be accounted for within 10 km of the plant. [29] Other modeling studies have shown that as much as 30% of sulfur emissions could be accounted for by dry deposition within 100 km of the plant. [31]

A more recent study relying on atmospheric measurements indicated sulphur from gas plant emissions were larger downwind and concentrations for SO_2 and sulphate reached levels four times the average concentration in Calgary, AB. SO_2 concentrations derived from passive monitors demonstrated wave like pattern in concentration trending upward again at distances approximately 20 km from the sour gas plant and that the pattern was mirrored in samples collected from vegetation, soil and surface waters. [32]

Considering the fact that a 28 MW air breathing machine consumes on the order of 89 kg/s (165 000 ACFM) of air, one certainly has to take interest.

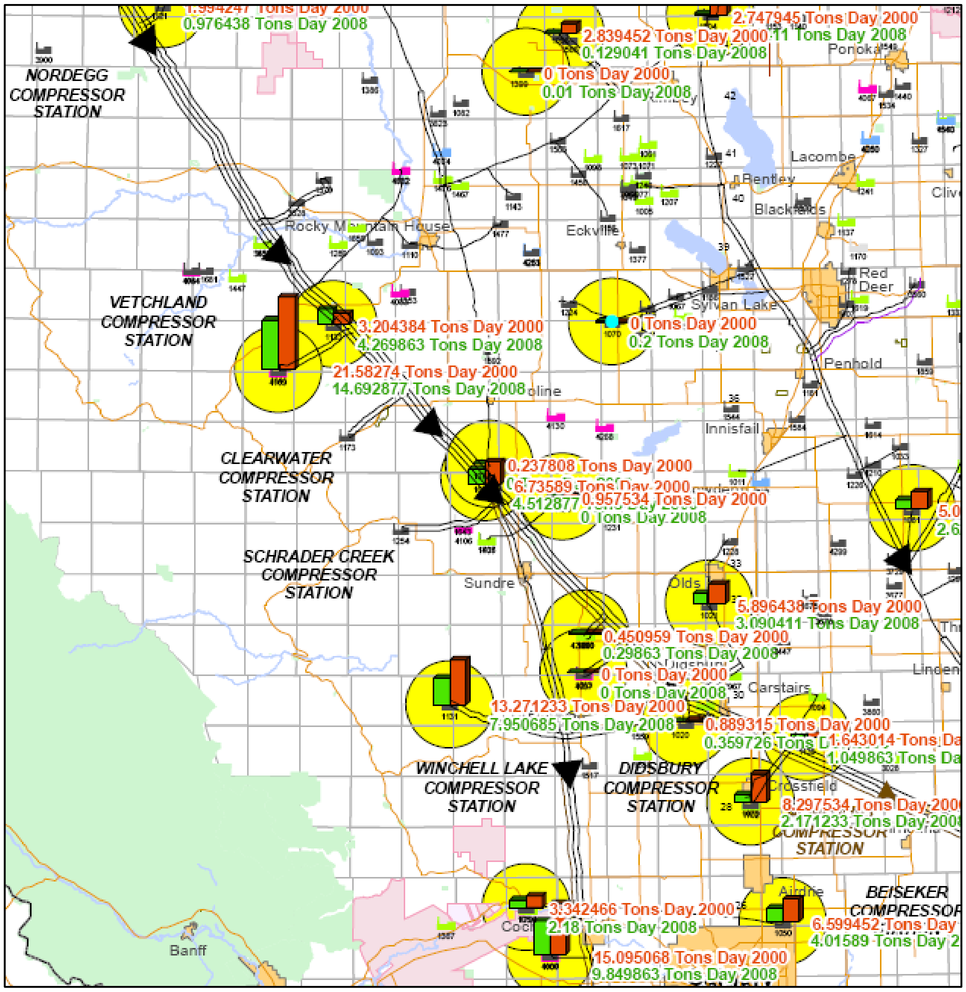


Figure 6: Active Sour Gas Processing Facilities near Schrader Creek Compressor Station – Average Daily SO_2 Output in 2008 is approx. 30 tonnes within 50km. Yellow circles represent 5km radii from plants.

4.2.2 – Flaring Activity

Not to be outdone, another source of significant SO2 emissions exists within the province in the form of flaring. Acid and solution gas flaring is somewhat more problematic in respect to volume and emitted species. Unlike sour gas treatment facilities which initially output only gaseous emissions, when wet, sour gas with hydrocarbon content if flared, carbon species and sulphates appear in the sulphur emissions. Such flaring can be a consequence of solution gas flaring, well test flaring, natural gas battery flaring, gas plant flaring or associated flaring when plant operations are interrupted for emergency or maintenance. Some characterization work on gaseous sulfur emissions from a sour oilfield battery flare collected 1.5-2.0 meters from the end of the flame found, as an example, concentrations of 6910 mg/m^3 of SO_2, 126 mg/m^3 of H_2S, 64 mg/m^3 of COS, 482 mg/m^3 of CS_2. They also included elemental sulphur at 157.35 mg/m^3 as well as mercaptans and sulphides. [33]

To place relative magnitudes in perspective relative emissions from Sour Gas Plants, 2009 SO_2 emissions from these activities province wide were on the order of 500 tonnes / day. [34] The distribution of activity within the province also tends to coalesce along and shadow mainline gas transmission right of ways in the foothills / west and southern parts of the province (Figure 7).

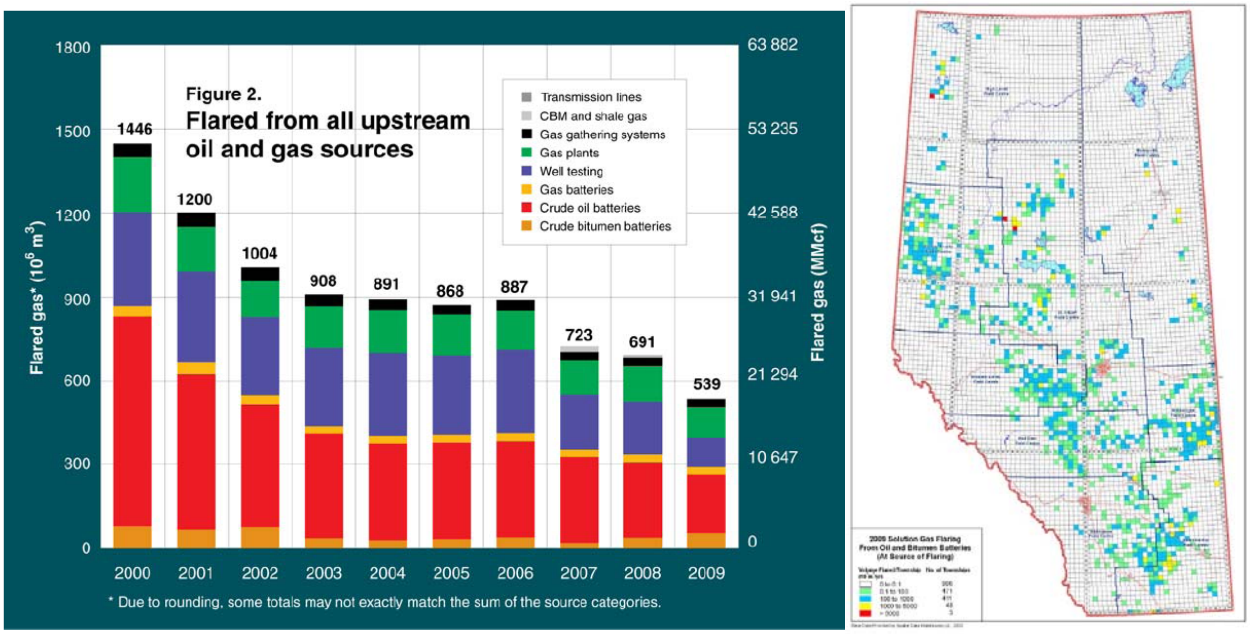


Figure 7: Composite image reflecting proportional breakdown of Upstream Industry Sources and province wide distribution. Images from ERCB ST60B-2010. [35]

4.2.3 – Coal Fired Generation and Oil Sands Activities

Coal Fired Power Generation, largely concentrated in the Wabamun area West of Edmonton and Sheerness near Hanna, and Oil Sands Operations, concentrated in Fort McMurray, offer their own respective emissions to the SO_2 burden. These are on the order of 356 tonnes/day and 425 tonnes/day respectively. [34]

4.2.4 – Air Quality Monitoring

Air Quality Monitoring is carried out within Alberta by the government utilizing specialized mobile monitoring equipment. This is in limited supply and as a result, the programs concentrates on populated areas and measuring frequency is quite sporadic and short duration. Nonetheless, this program does seek to quantify gaseous readings against Alberta Ambient Air Quality Objective levels for a myriad of substances. Threshold objectives for SO_2 are as follows [36]:

- 1-hour Average = 450 $\mu g/m^3$ = 172 ppb_v.
- 24-hour Average = 150 $\mu g/m^3$ = 57 ppb_v.
- Annual Average = 30 $\mu g/m^3$ = 11 ppb_v

For comparison, US EPA maintains a NAAQS SO_2 Standard as follows [37]:

- 3-hour Average = 1308 $\mu g/m^3$ = 500 ppb_v. (Secondary)
- 24-hour Average = 366 $\mu g/m^3$ = 140 ppb_v.
- Annual Average = 79 $\mu g/m^3$ = 30 ppb_v.

The Air Monitoring Program reports yearly by region. Data from MAML (Mobile Air Monitoring Lab) generally support that the AAAQO are not exceeded during the monitoring period although occasionally anomalies and higher readings (SO_2 and Total Reduced Sulphur are occasionally reported in proximity to Sour Gas Processing plants. [38] This is somewhat consistent with a much earlier 1973 finding near Balzac gas plant whereby twenty-eight “pollution episodes” occurred in a twelve month period with a ground level SO_2 concentration of 150 ppb_v being exceeded. [31] It is noted that these MAML surveys are short duration and do not concern themselves with sulphates or other sulphur species that maybe of interest to this study. As such, it is unclear what levels would be like at the inlets of GT’s of interest.

4.2.5 - Perspective

For some perspective, expanding on Table 3 to consider the contribution of these inlet airborne SO_2 contaminates to flue gas concentration to support corrosion reactions, assuming a worse case 172 ppb_v concentration, the following Table 4 provides results for the same assumed fuel gas levels.

Table 4: Flue Gas SO_2 for AAAQO 1-hr Threshold Air Concentration and Assumed Fuel Gas Sulphur Levels.

Fuel Total Sulfur	Fuel Total Sulfur	Mass Sulfur From Fuel	Exhaust Mass SO2 from Fuel	Mass SO2 Inlet	Total Exhaust Mass SO2	Exhaust SO2 Concentration
mg/m^3	ppmv	kg/day	kg/day	kg/day	kg/day	% mol
115.00	85.000	21.995	43.988	2.9186	46.907	2.67031
12.17	9.000	2.328	4.655	2.9186	7.574	0.43116
7.63	**5.640**	**1.495**	**2.991**	**2.9186**	**5.909**	**0.33640**
2.70	1.996	0.516	1.033	2.9186	3.951	0.22494

The salient result pointed out shows that for fuel gas Total Sulfur levels less than about 5.6 ppm_v (which typically is the case), airborne SO2 at the inlet at the AAAQO level would represent a larger proportion of sulphur in the combustion exhaust gases than those borne by the fuel.

Further, given the above coupled with the undeniable corrosion evidence observed, there may be sufficient cause to entertain a long term inlet air evaluation that would also consider monitoring the presentation of SO_2 and sulphate species at select compressor unit inlet systems. As it stands, without such data, the flue gas conditions are considered to have low S_2 partial pressures that do not appear to contravene published expectations for GT exhaust gases.

4.3 Build and Assembly Lubricants

Another source of potentially problematic contaminates (sulphur and otherwise) includes anti-seize or anti-galling compounds. These may be introduced at rotor build, balancing operations, manipulation with fixtures and tooling, or at installation at site. Indeed some examples in Figure 3 appear consistent with such possibility.

4.3.1 – Molybdenum Disulphide (MoS_2)

MoS_2 has been researched for a very long time and has found use in many lubrication applications. Nevertheless, there has been considerable confusion over its use, particularly in respect to high temperature applications, with incorrect data on melting and sublimation temperatures. [39] While a dissociation temperature is quoted as 1370 °C, this is specifically in a non-oxidizing environment and sublimation temperature of 1050 °C is under vacuum. As a consequence, in vacuum or inert environments it is thermally stable from cryogenic to high temperatures. [40]

The oxidation characteristics in oxidizing/air atmospheres however are quite different. Thermal oxidation rate of MoS_2 in air below 300 °C is slow and difficult to measure and that it remains slower than tungsten disulphide under 388 °C, although moisture tends to lower the onset of more rapid oxidation to 350 °C. [40] Above 370°C there is an increasingly rapid oxidation to molybdenum trioxide with the reaction classed by some as highly exothermic in the range 500-600°C. [40]

$$2\ MoS_2 + 7\ O_2 \rightarrow 2\ MoO_3 + 4\ SO_2 \qquad (1)$$

Some have cast MoO_3 as abrasive in the friction zone. [41] This has been vehemently countered by others citing numerous tests, but acknowledged that oxidation products can increase friction. [39] Size of the MoS_2 particles can influence oxidation rates (sub micron faster than coarser), but these also need to be matched to the surface condition of the substrates which they are intended to protect. [39]

Recall also that Molybdenum oxides, if coexisting with Na_2SO_4, can support a self induced acid fluxing. Another potential issue is the remnant MoO_3, which has a relatively low melting temperature of 795°C. [42] Temperatures near a post should not experience temperatures such as this for prolonged periods during normal operation. However, during an abnormal situation with a truncated GG spool-down that does not allow carcass heat rejection, it may be possible to experience such temperatures for short duration. Further, any formed porous aggregates can entrap the SO_2 by-products, increasing locally their partial pressures and supporting corrosion reactions.

Given the oxidizing environment that exists in a gas turbine combustion products stream (15-16% O2) with a reasonable moisture content (depending on fuel gas, but typically 6-9%), the above confirm that Molybdenum Disulphide based lubricants should be regarded as inappropriate for hot-end applications.

4.3.2 – Other Anti-Seize Constituents of Note

Many anti-seize compounds feature MoS_2 but also include other compounds that may be reactive and therefore problematic with the alloys in question at elevated temperatures. Some of these and constituents in other compounds may include:

- Red Lead (Lead Monoxide), Copper Powder, Zinc Pyrosulphate, Tricalcium Phosphate.
- Surfactant additives such as Barium or Sodium Sulphanol.
- Chlorine.
- Zinc.
- Silver is very reactive with sulphur but also can cause liquid metal embrittlement. It should be avoided in hot sections.
- Fillers that introduce additional species Talc (Mg), Mica (K, Na, Ca), Bentonites;

Certainly the equipment OEM needs to define the suitable product and be consulted for guidance but the operator should remain diligent and ensure that a quality program ensures only approved high-temperature compounds are used. Equally critical is that adequate controlled instructions and a training regimen exist to ensure that such compounds are applied only in specified locations and that care is taken to ensure spill and so that unnecessary superfluous application is avoided.

4.4 Limnogeology of the Prairies

Limnogeology is the study of lake systems and their deposits. This field of science provides a very interesting perspective on the uniqueness of a large portion of TransCanada's operating theater in the Western Canadian prairies and the Dakotas.

In much of the Northern Great Plains, saline and hypersaline lacustrine brines are the only surface waters present. This is attributed to the fact that the Missouri Coteau and adjacent areas has a lack of integrated drainage such that the area contains many closed basins with only three defined drainage paths by river systems. [43] The underlying geologic formations include stacked carbonate-evaporite cycles and dissolution of these by hydrologic process is suggested to have provided the source for the ions that are trapped in these closed basins in waters that make this region so remarkable (estimates range from 4-10 million lakes or wetlands in the region with densities as high 90-120 lakes / km^2). [43]

Climatic factors including temperature and evaporation to precipitation ratio play a definite role in the function of the lakes with the region receiving 40 cm of precipitation / year while over 1.5 meters of water can be lost annually to evaporation

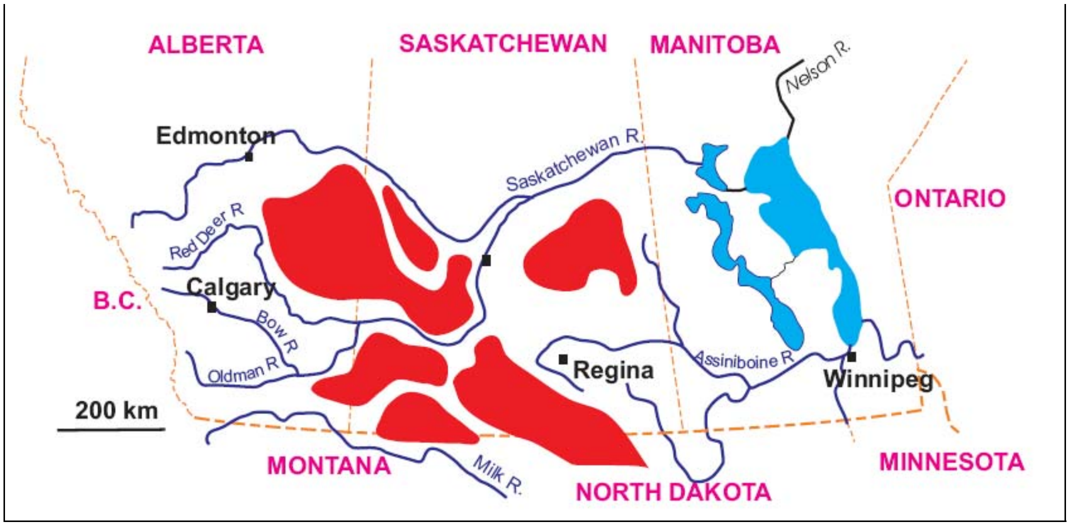


Figure 8: Closed basins of the Great Plains. Image Reproduced from [43].

from open water bodies. [43] In so far as the topic at hand is concerned, wind also dictates processes in the lakes, as average wind speed is moderate to high, which aids evaporation and in current and wave generation and therefore sedimentation and deposition and erosion. It is an agent for transport of sediment and salts into and out of the lakes. [43]

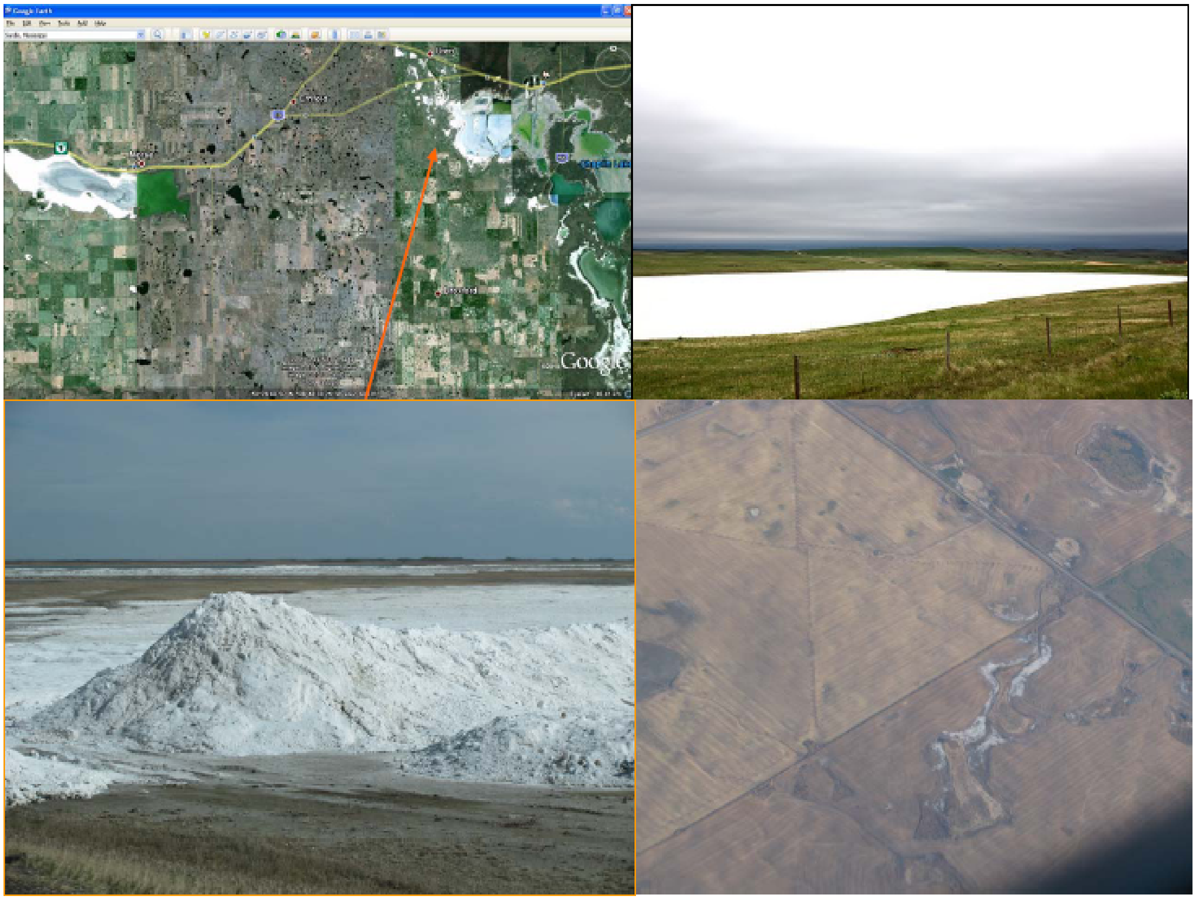


Figure 9: Examples of Evaporite Lakes (Chaplin Lake, Red Lake) and an aerial view of a wet/dry playa. Lake Ingebright is North Americas largest Na_2SO_4 deposit. [43]

There are 812 recognised and documented basins that have been classified first based on size (> 100 km^2), then based on whether they are shallow (<3m), and finally whether they are permanent lakes or intermittent lakes (playas). Industrial harvesting of minerals tends to prefer larger, deep basins due to the way minerals settle and precipitate within them. [44] While all the lakes offer the potential for generation of loose, airborne salt contaminants, it is the smaller, most numerous (54% of the total) intermittent playas that spend a larger proportion of time dried out and capable of generating airborne dust and debris.

In respect to salinity and composition, even though all the lakes in question have similar origins, the waters now show a remarkable diversity in respect to ionic composition. Although there was initially thought to be a predominance of sodium and sulphate components, it is now understood that sulphate and carbonate rich lakes dominate the Prairies (95%) and that fewer than 5% are Chlorine rich (including Chaplin, Quill Lakes and Bigstick) which again differentiates the region from the rest of the world. [43]

Figure 10, borrowed from the Last and Ginn work, presents a histrogram depicting the distribution of lakes by salinity. It is further noted that the highest salinity lakes tend to occur in east-central Alberta and west-central and southern Saskatchewan (and Dakotas). [43] Thus, the worst portion of this "evaporate belt" theater coincides with a high density of equipment on the NGTL South East mainline, FHPL Alberta and Saskatchewan, The Mainline in Central Region and the upper portion of the NBPL line (Figure 11).

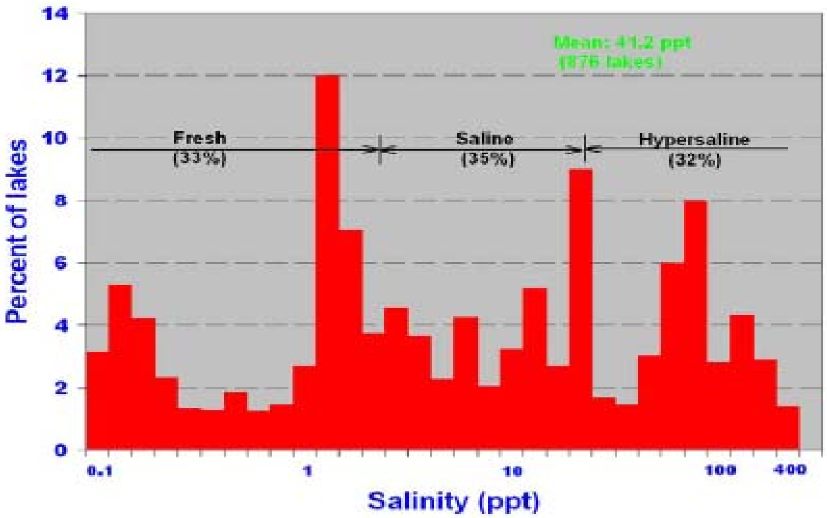


Figure 10: Salinity of lakes in the Great Plains region of Western Canada. Reproduced from [43].

Table 5 - Mean Brine Compositions of Saline and Hypersaline Lakes in Select Areas from [43].

Region	**Ca**	**Mg**	**Na**	**K**	**HCO3**	**CO3**	**Cl**	**SO4**	**TDS**
	mmol/l	mmol/l	mmol/l	mmol/l	mmol/l	mmol/l	mmol/l	mmol/l	ppt
Eastern Prairies	4	24	4	1	6	1	2	24	3
Central Saskatchewan	19	149	193	5	7	3	54	251	22
SW Saskatchewan & SE Alberta	12	93	**1088**	4	96	36	29	**1073**	80
West Central Saskatchewan and East Central Alberta	3	144	**1362**	10	268	44	107	**1125**	102

The sedimentary processes and details of the mechanism by which minerals precipitate are well beyond the scope of this effort. In respect to visualizing the playas, it is worth remarking that these are an ever changing canvas, where diurnal temperature changes and water precipitation ingress cause salinities to drop and rise with resultant significant dissolution. That is to say, appearances change certainly by season, but even during the day. [43] Finally, it is worthwhile to identify the commonly formed minerals in the lakes identified by Last and Ginn which is provided in Table 6.

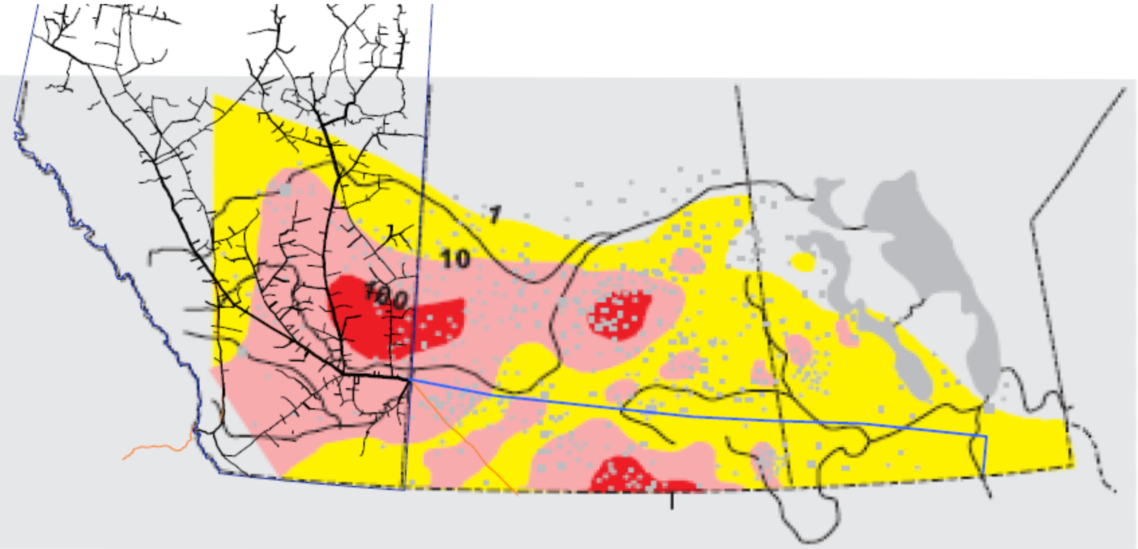


Figure 11: Variation of salinity (TDS – Contours are logarithmic) in lakes with TCPL facilities overlain. Adapted from [43].

Table 6: Minerals Formed in Saline Lakes of the Great Plains. Adapted from [43].

Class	Mineral Name	Composition	Occurrence
Carbonates	Aragonite	$CaCO_3$	Very Common
	Calcite	$CaCO_3$	Very Common
	Magnesite	$MgCO_3$	Common
	Magnesian Calcite	$(Mg_xCa_{x-1})CO3$	Very Common
	Protodolomite	$CaMg(CO_3)_2$	Very Common
Sulphates	**Bloedite**	$Na_2Mg(SO_4)_2\ 4H_2O$	Very Common
	Epsomite	$MgSO_4\ 7H_20$	Common
	Gypsum	$CaSO_4\ 2H_2O$	Very Common
	Hexahydrite	$MgSO_4\ 4H_2O$	Common
	Kieserite	$MgSO_4\ H_2O$	Common
	Mirabilite	$Na_2SO_4\ 10\ H_2O$	Very Common
	Mercalite	$KHSO_4$	Very Rare
	Potassium Alum	$KAl(SO_4)_2\ 12H_2O$	Very Rare
	Thenardite	Na_2SO_4	Very Common
Chlorides	Bischofite	$MgCl_2\ 6H_20$	Very Rare
	Halite	$NaCl$	Rare

4.5 Road Dust Contaminants

A final consideration that warrants concerns are gravel roads. These are invariably the network of access ways to reach remote compressor station locations in the prairie and in the mountainous foothills of the sour gas corridor. Whereas traffic on the prairie roads has not likely increased significantly (although perhaps changing with increased drilling activity in Saskatchewan), traffic on roads in the sour gas corridor has significantly increased since the time these older or legacy units were commissioned. This is owing to drilling activity, forestry activity, and well servicing that is much more active.

Consequences of this include several additional potential contaminant sources:

- The dust burden reaching inlets has increased, representing issues for filtration systems and associated costs.
- Depending on the source of the gravel used on the road and its maintenance, it can include associated minerals such as anhydrite ($CaSO_4$) and pyrite (FeS_2). As roads dry out, this mineral dust is added to the burden.
- Dust Suppression has become desirable in areas where residential areas have encroached. Dust suppression methods include application of sugar Beet Molasses, Sodium lignin sulphonate as well as calcium brines including $CaCl_2$ and $MgCl_2$ (25-40%). The latter two are of potential interest.
- Calcium brines have also fallen into favor as base stabilizers. These harden surfaces and reduce rutting, allowing grading intervals to be extended. In some cases, private roads such as CANFOR are said to be applying these.

Thus depending on what the situation is near the plant, it may be a sensible strategy to consider paving a local section of road to reduce the dust burden and contaminates reaching the filtration system.

5 Contaminant Deposition

5.1 Site Examples

In the evaporite theater and the foothills “sour gas corridor”, sulphates and other evaporites have been found outside the inlet plena, in inlet filter samples, in some cases in the inlet on splitters and acoustic mesh (sometimes as reaction products with zinc from those structures), on gas generator compressor blading and secondary air system pathways and on engine exhaust diffusers. The salt deposits and other contaminates tend to accumulate most significantly in the first three or four stages of the axial compressors. This is consistent with experience on offshore units and that reported by others. [44] Ultimately, during Power Turbine teardowns, reactive species K, S, and Na have been recovered and in some cases, enough of a sample to employ XRD and confirm $CaSO_4$ and/or Na_2SO_4, amongst others. What follows are a series of figures (12-19) depicting some examples and analysis from various sites.

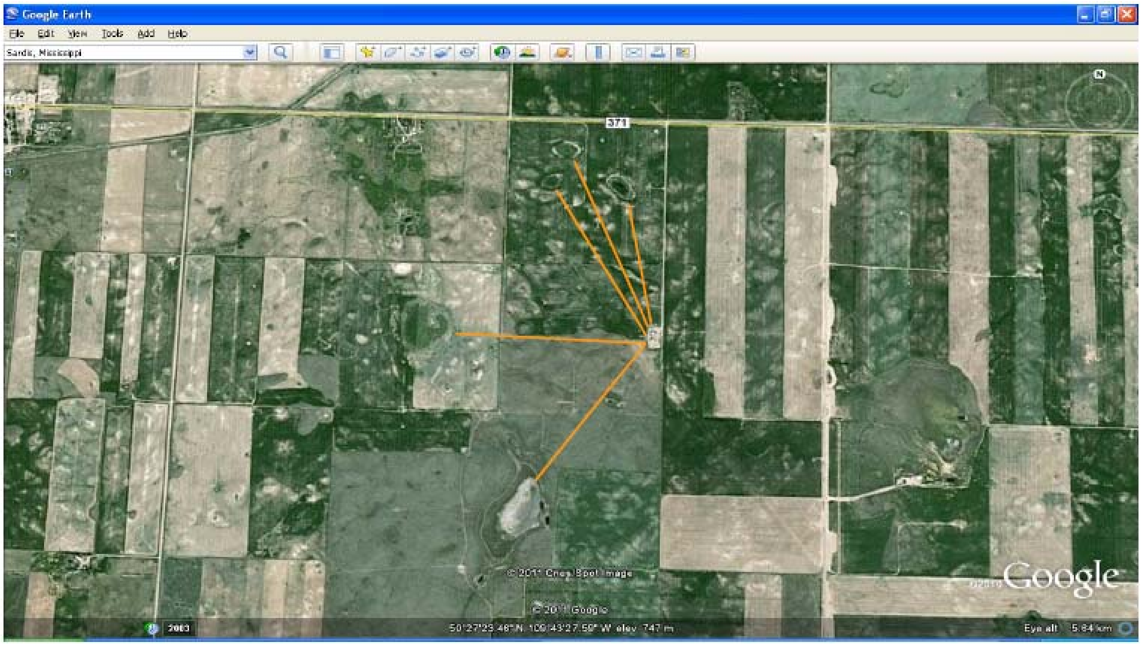
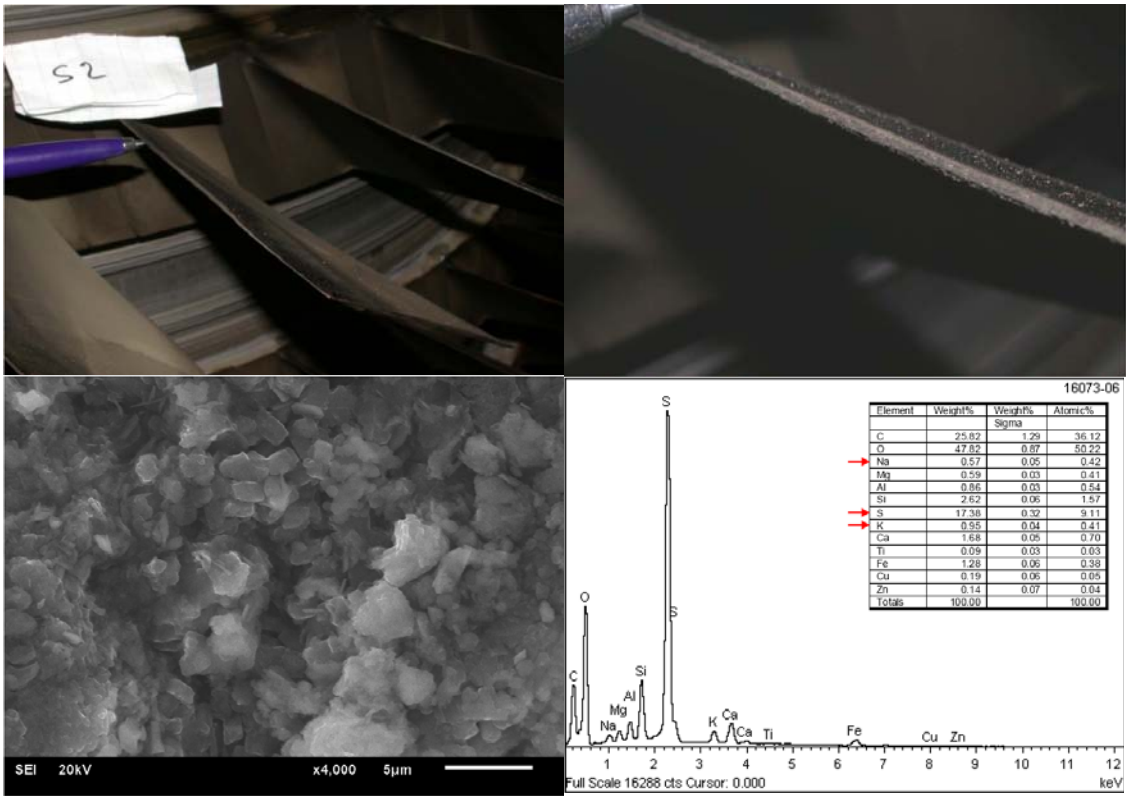
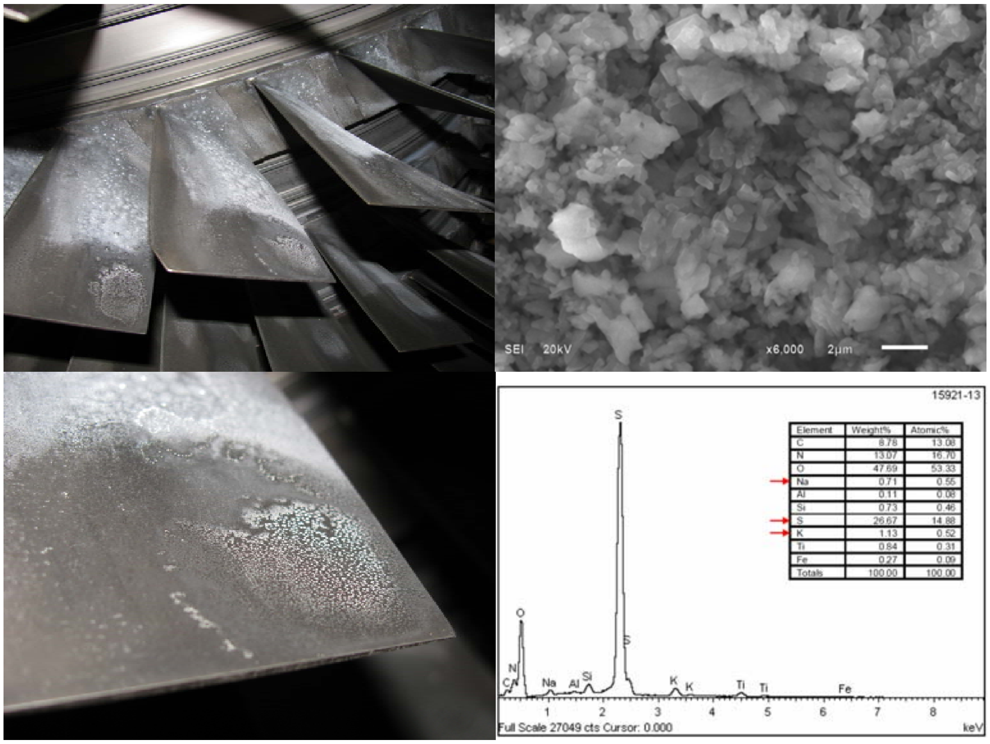


Figure 12: Richmound C/S (Sask) Surrounded by five lakes (within 950 m) and numerous small playas.



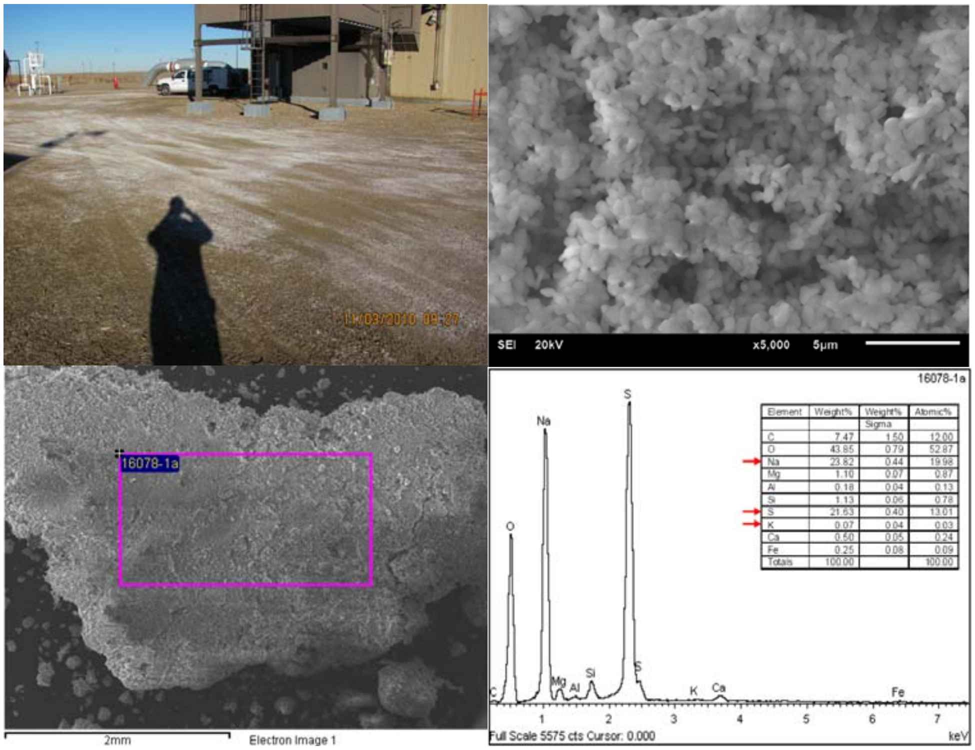
Element	Weight%	Weight% Sigma	Atomic%
C	25.82	1.29	36.12
O	47.82	0.87	50.22
Na	0.57	0.05	0.42
Mg	0.59	0.03	0.41
Al	0.86	0.03	0.54
Si	2.62	0.06	1.57
S	17.38	0.32	9.11
K	0.95	0.04	0.41
Ca	1.68	0.05	0.70
Ti	0.09	0.03	0.03
Fe	1.28	0.06	0.38
Cu	0.19	0.06	0.05
Zn	0.14	0.07	0.04
Totals	100.00		100.00

Figure 13: Richmound C/S: ESN 1750-116 IPC Stage Two blade deposits showing reactive species Na, S and K. GG was 3000 hours since last compressor wash. [45]



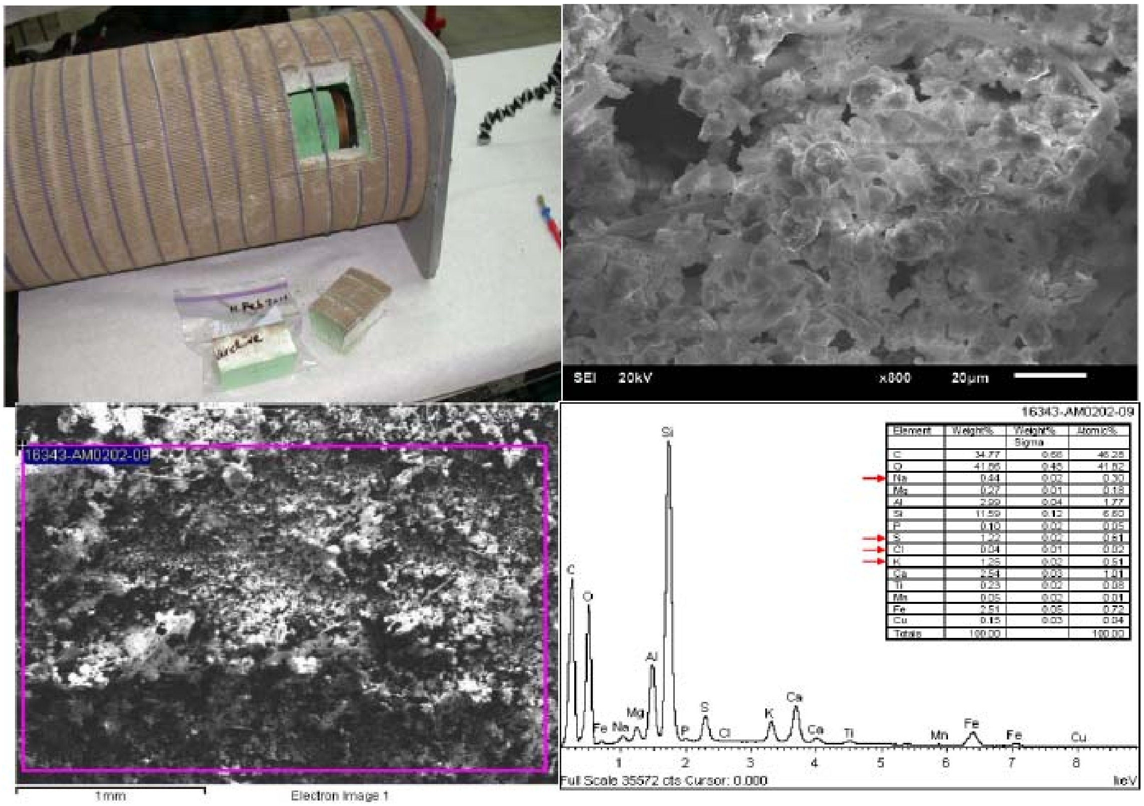
Element	Weight%	Atomic%
C	8.78	13.08
N	13.07	16.70
O	47.69	53.33
Na	0.71	0.55
Al	0.11	0.08
Si	0.73	0.46
S	26.67	14.88
K	1.13	0.52
Ti	0.84	0.31
Fe	0.27	0.09
Totals	100.00	100.00

Figure 14: Deposits on IPC of ESN 1750-120 from Burstall (Sask) Compressor C/S. Engine was 530 hours since compressor wash. SEM Images from [46].



Element	Weight%	Weight% Sigma	Atomic%
C	7.47	1.50	12.00
O	43.85	0.79	52.87
Na	23.82	0.44	19.98
Mg	1.10	0.07	0.87
Al	0.18	0.04	0.13
Si	1.13	0.06	0.78
S	21.63	0.40	13.01
K	0.07	0.04	0.03
Ca	0.50	0.05	0.24
Fe	0.25	0.08	0.09
Totals	100.00		100.00

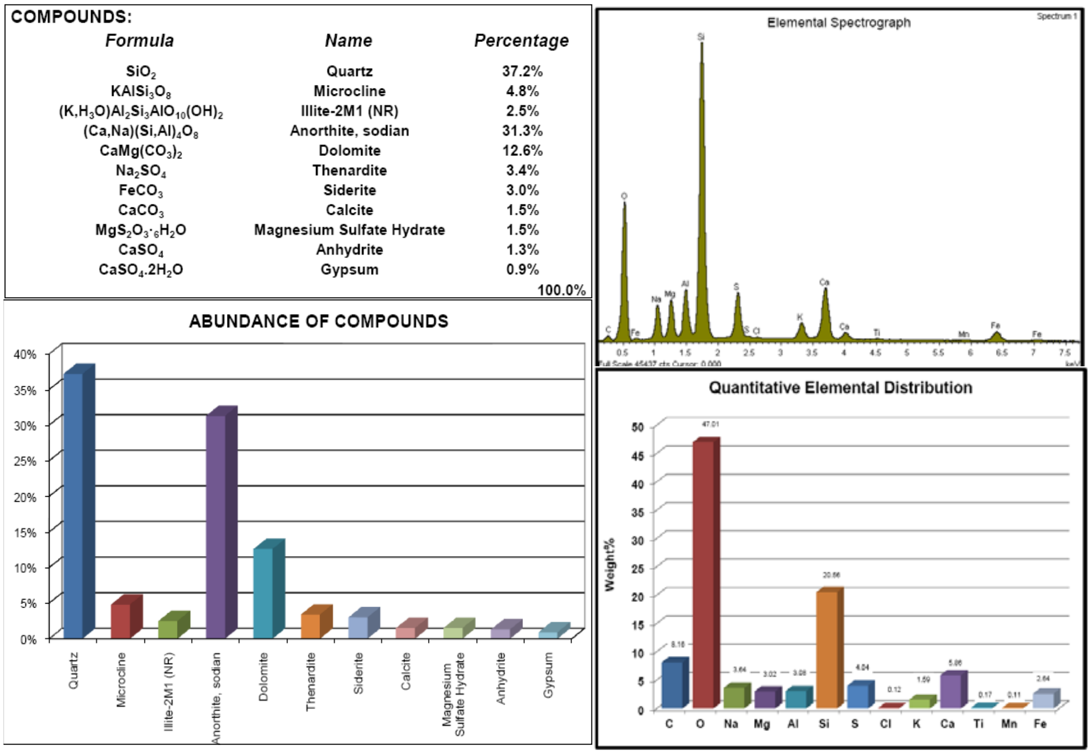
Figure 15: Jenner C/S (Alberta). Evaporite in yard and under plenum. SEM Images from [47].



16343-AM0202-09

Element	Weight%	Weight% Sigma	Atomic%
C	34.77	0.66	46.28
O	41.56	0.45	41.62
Na	0.44	0.02	0.30
Mg	0.27	0.01	0.18
Al	2.99	0.04	1.77
Si	11.59	0.13	6.60
P	0.10	0.02	0.05
S	1.22	0.02	0.61
Cl	0.04	0.01	0.02
K	1.26	0.02	0.51
Ca	2.54	0.03	1.01
Ti	0.23	0.02	0.08
Mn	0.05	0.02	0.01
Fe	2.51	0.05	0.72
Cu	0.15	0.03	0.04
Totals	100.00		100.00

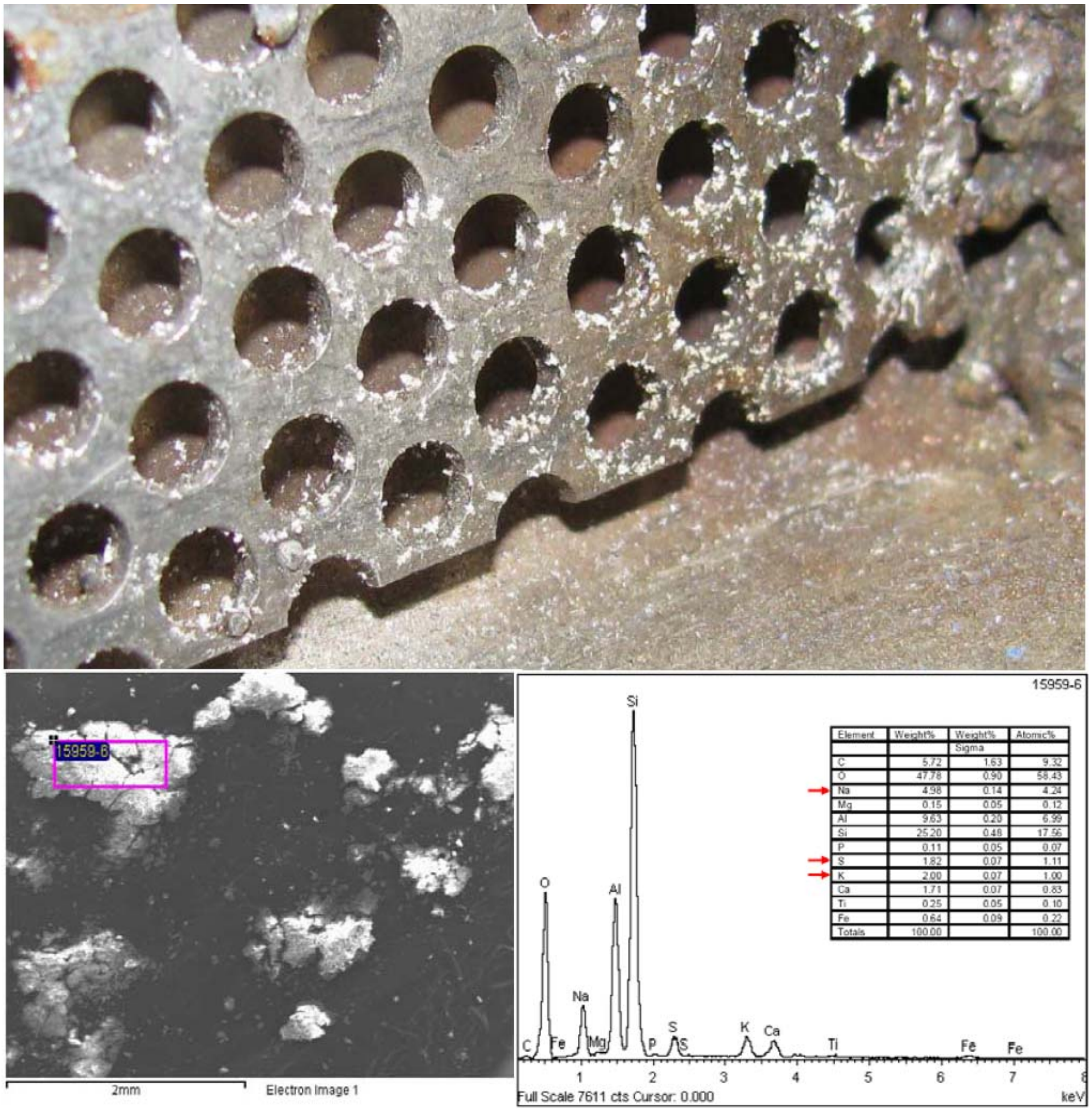
Figure 16: Monchy C/S (Sask) Filter Debris Analysis by SEM [48].



COMPOUNDS:

Formula	Name	Percentage
SiO_2	Quartz	37.2%
$KAlSi_3O_8$	Microcline	4.8%
$(K,H_3O)Al_2Si_3AlO_{10}(OH)_2$	Illite-2M1 (NR)	2.5%
$(Ca,Na)(Si,Al)_4O_8$	Anorthite, sodian	31.3%
$CaMg(CO_3)_2$	Dolomite	12.6%
Na_2SO_4	Thenardite	3.4%
$FeCO_3$	Siderite	3.0%
$CaCO_3$	Calcite	1.5%
$MgS_2O_3{\cdot}_6H_2O$	Magnesium Sulfate Hydrate	1.5%
$CaSO_4$	Anhydrite	1.3%
$CaSO_4.2H_2O$	Gypsum	0.9%
		100.0%

Figure 17: Monchy C/S (Sask.) XRD Analysis of gravel under filter hood. [48] This EDS & XRD analysis match what was in the filter (Fig.16). [48]

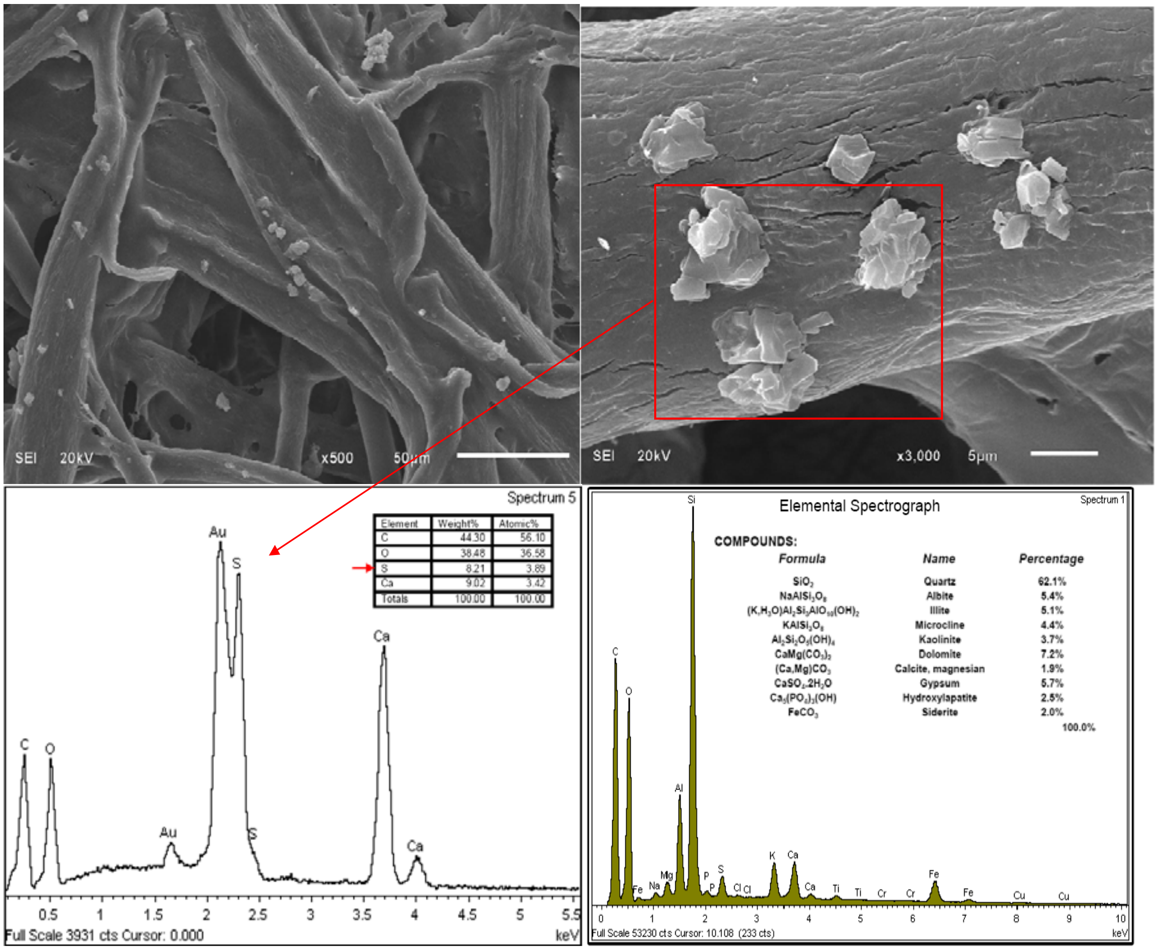


Element	Weight%	Weight% Sigma	Atomic%
C	5.72	1.63	9.32
O	47.78	0.90	58.43
Na	4.98	0.14	4.24
Mg	0.15	0.05	0.12
Al	9.63	0.20	6.99
Si	25.20	0.48	17.56
P	0.11	0.05	0.07
S	1.82	0.07	1.11
K	2.00	0.07	1.00
Ca	1.71	0.07	0.83
Ti	0.25	0.05	0.10
Fe	0.64	0.09	0.22
Totals	100.00		100.00

Figure 18: Latornell C/S (Alberta) White Crystalline deposits inside inlet plenum on acoustic lining, upstream of splitters. [49]

5.2 Water Wash Migration

As has been demonstrated, sulphate salts are making it through many of the inlet systems. It was necessary to understand how these contaminates were making there way through the system and accumulating as far rearward as the power turbine, and further, finding there way into the rotor stator cavities. In one design, IP Compressor delivery air is fed as rim cooling air into both cavities. However, in the other design, where deposits were being found, no cooling air was provided to the second cavity. Compressor soak wash fluid migration studies were conducted. Effluent was captured from the various openings and drained and sent for analysis by ICP-OES. See Figures 20-21.



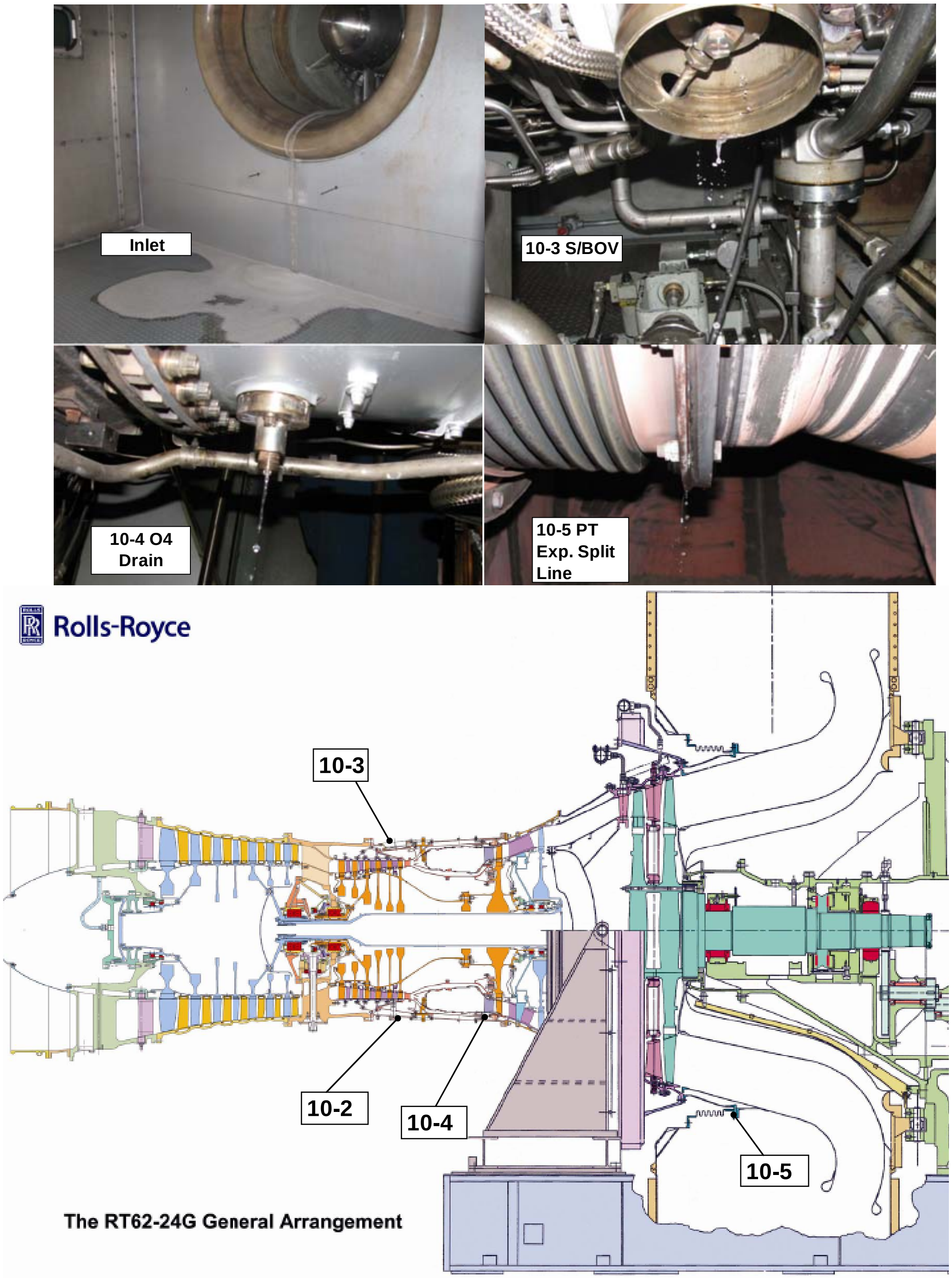
Element	Weight%	Atomic%
C	44.30	56.10
O	38.48	36.58
S	8.21	3.89
Ca	9.02	3.42
Totals	100.00	100.00

COMPOUNDS:

Formula	*Name*	*Percentage*
SiO_2	Quartz	62.1%
$NaAlSi_3O_8$	Albite	5.4%
$(K,H_3O)Al_2Si_3AlO_{10}(OH)_2$	Illite	5.1%
$KAlSi_3O_8$	Microcline	4.4%
$Al_2Si_2O_5(OH)_4$	Kaolinite	3.7%
$CaMg(CO_3)_2$	Dolomite	7.2%
$(Ca,Mg)CO_3$	Calcite, magnesian	1.9%
$CaSO_4.2H_2O$	Gypsum	5.7%
$Ca_5(PO_4)_3(OH)$	Hydroxylapatite	2.5%
$FeCO_3$	Siderite	2.0%
		100.0%

Figure 19: Inlet filter analysis from Latornell C/S. Lower Right Hand Side is XRD of filter inlet side debris with Gypsum, K and Trace Chlorine. Downstream side particle EDS shows Ca, S and O. (Au Sputter). [49]

Figure 20: Appreciable amount of wash fluid reaching the exhaust system.



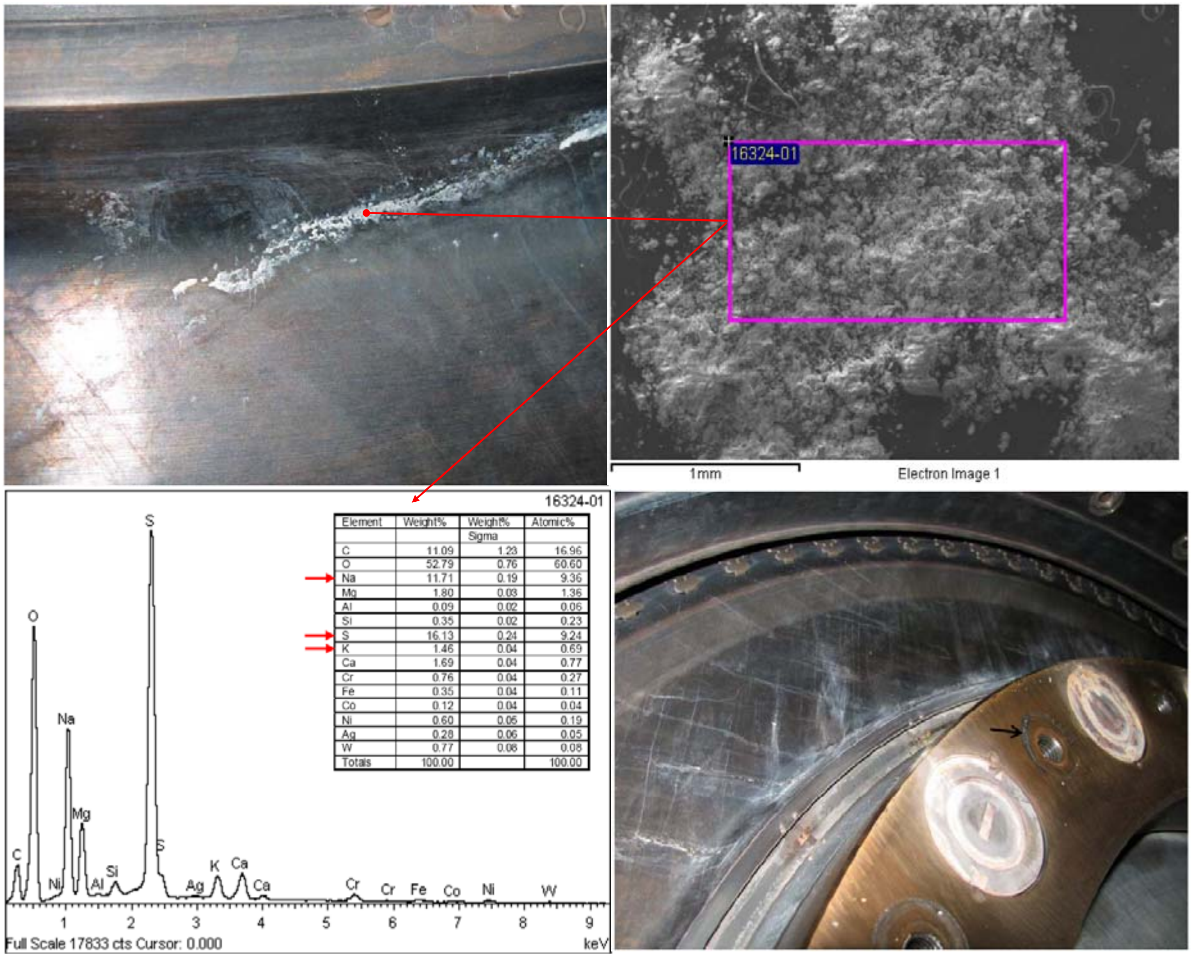
Sample	Sodium (ppm)	Chloride (ppm)	Sulphate (ppm)	Potassium (ppm)
#10-1 A2 Wash Water	-	0.19	0.53	-
#10-2 HP3 BOV Rinse	4.6	0.77	104	4.05
#10-3 SBOV Rinse	5.9	0.73	141	6.80
#10-4 04 Drain	16.7	20.4	359	25.1
#10-5 PT Exhaust Expansion Joint Split	21.7	1.4	411	28.8

Figure 21: ICP-OES Analysis results from [50]. Image courtesy of Rolls-Royce.

It was clearly evident that an appreciable amount of water wash fluid was reaching the PT exhaust and therefore highly likely that a significant amount was entering the rotor stator cavities through the axial clearances. The chemical analysis revealed that the soluble minerals were increasing in concentration the further back in the gas path from which samples were taken. These rotor stator cavities do not receive significant flows when in service. Therefore, precipitated salt deposits appear to persist for some time. This finding is concerning, but unfortunately consistent with visual cues noticed during tear downs at numerous different vendor sites. As it turns out, there are also documented precedents for wash-migrated corrosive species, albeit a coastal site in the UK. [51]

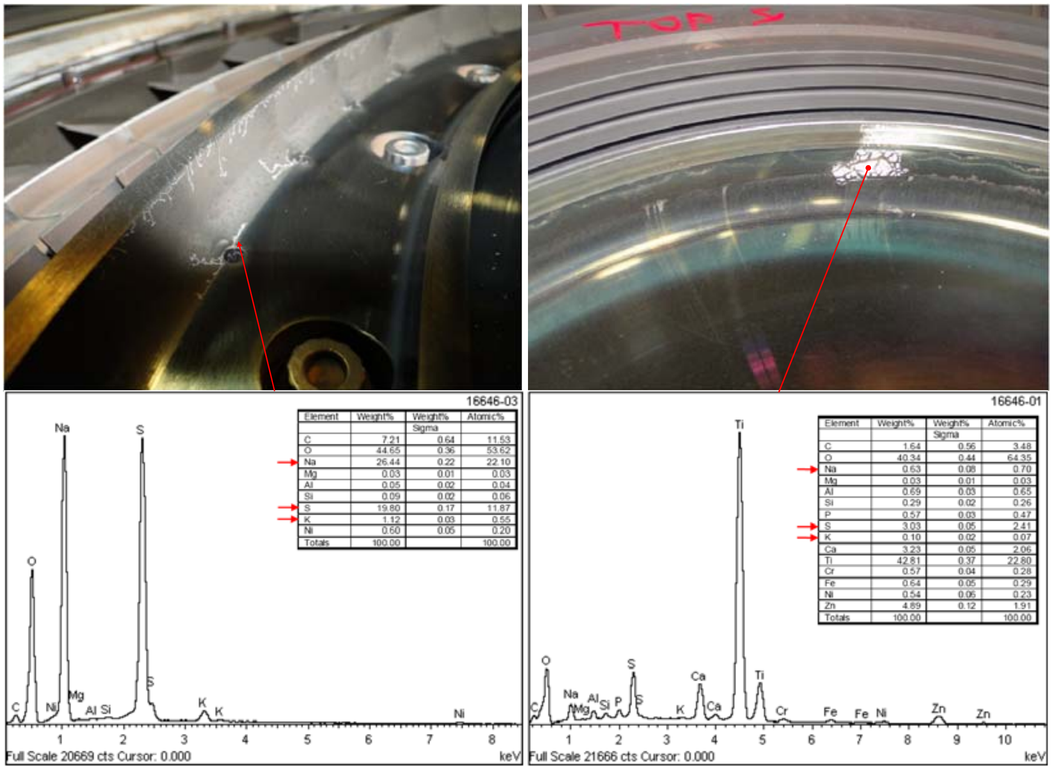
5.3 – Equipment Tear Down Samples

A number of vendors were visited during the course of this investigation and in all cases, there were visual cues that such migration occurs in most designs as a consequence of either fired or soak washes. None appear immune in the “belt”.



Element	Weight%	Weight% Sigma	Atomic%
C	11.09	1.23	16.96
O	52.79	0.76	60.60
Na	11.71	0.19	9.36
Mg	1.80	0.03	1.36
Al	0.09	0.02	0.06
Si	0.35	0.02	0.23
S	16.13	0.24	9.24
K	1.46	0.04	0.69
Ca	1.69	0.04	0.77
Cr	0.76	0.04	0.27
Fe	0.35	0.04	0.11
Co	0.12	0.04	0.04
Ni	0.60	0.05	0.19
Ag	0.28	0.06	0.05
W	0.77	0.08	0.08
Totals	100.00		100.00

Figure 22: Vendor 2: prominent sodium and sulphur levels detected. Note the drip like pattern to the residue, which are suggestive that these were deposited when the unit PT was static as during soak wash. [52]



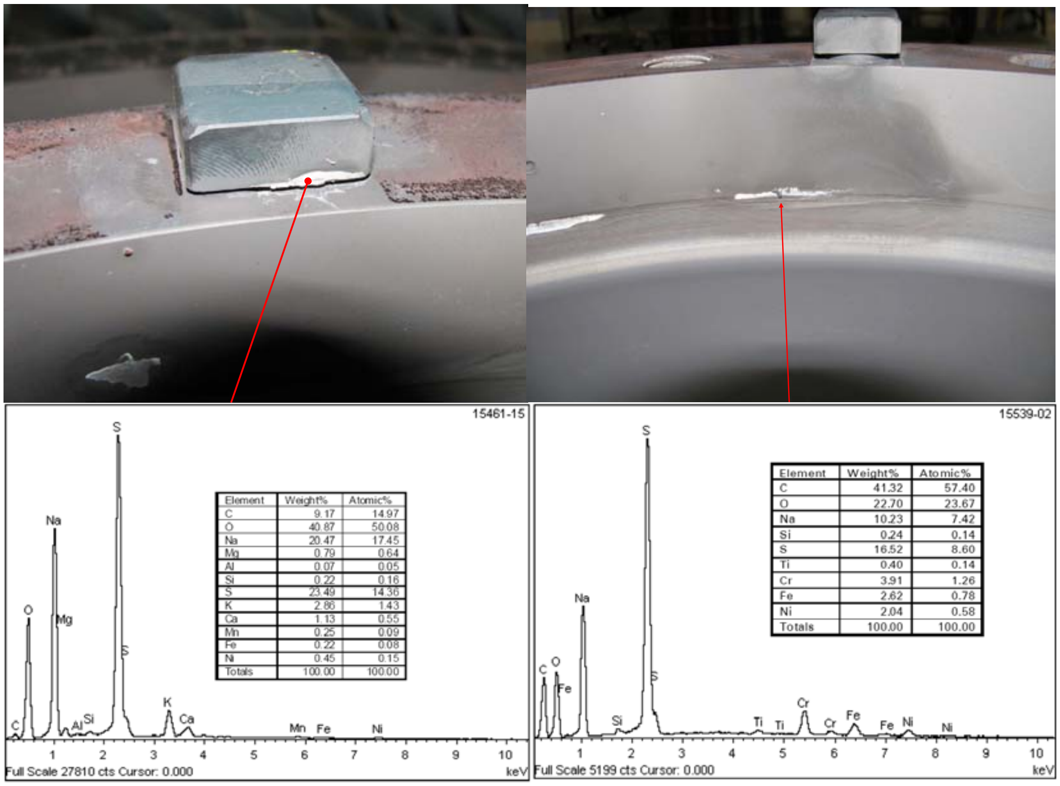
16646-03

Element	Weight%	Weight% Sigma	Atomic%
C	7.21	0.64	11.53
O	44.65	0.36	53.62
Na	26.44	0.22	22.10
Mg	0.03	0.01	0.03
Al	0.05	0.02	0.04
Si	0.09	0.02	0.06
S	19.80	0.17	11.87
K	1.12	0.03	0.55
Ni	0.60	0.05	0.20
Totals	100.00		100.00

16646-01

Element	Weight%	Weight% Sigma	Atomic%
C	1.64	0.56	3.48
O	40.34	0.44	64.35
Na	0.63	0.08	0.70
Mg	0.03	0.01	0.03
Al	0.69	0.03	0.65
Si	0.29	0.02	0.26
P	0.57	0.03	0.47
S	3.03	0.05	2.41
K	0.10	0.02	0.07
Ca	3.23	0.05	2.06
Ti	42.81	0.37	22.80
Cr	0.57	0.04	0.28
Fe	0.64	0.05	0.29
Ni	0.54	0.06	0.23
Zn	4.89	0.12	1.91
Totals	100.00		100.00

Figure 23: Vendor 3. Evidence of crystalline depositic having worked through secondary air systems and a “water mark” deposit with some apparent remnant anti-seize. [53]



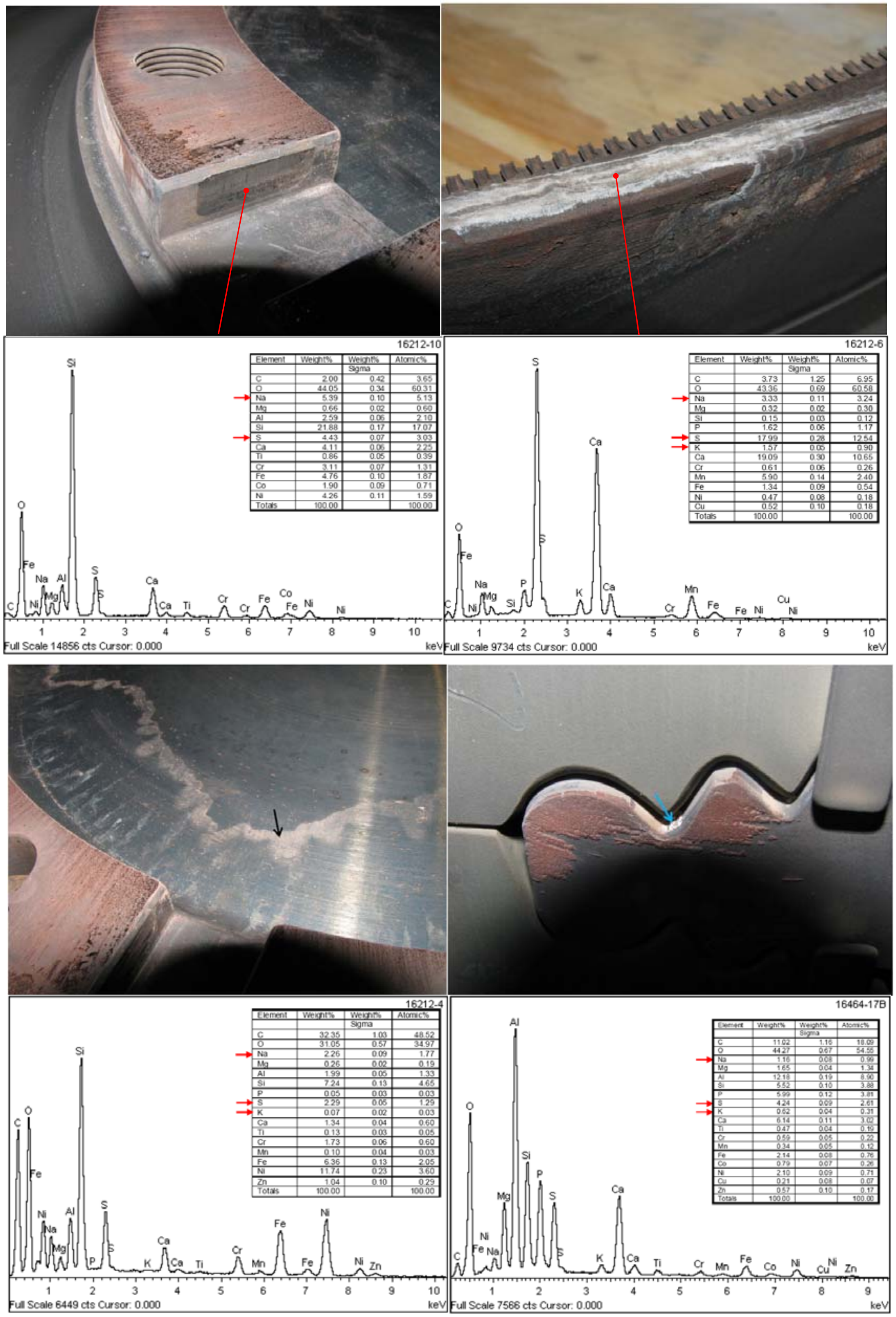
15461-15

Element	Weight%	Atomic%
C	9.17	14.97
O	40.87	50.08
Na	20.47	17.45
Mg	0.79	0.64
Al	0.07	0.05
Si	0.22	0.16
S	23.49	14.36
K	2.86	1.43
Ca	1.13	0.55
Mn	0.25	0.09
Fe	0.22	0.08
Ni	0.45	0.15
Totals	100.00	100.00

15539-02

Element	Weight%	Atomic%
C	41.32	57.40
O	22.70	23.67
Na	10.23	7.42
Si	0.24	0.14
S	16.52	8.60
Ti	0.40	0.14
Cr	3.91	1.26
Fe	2.62	0.78
Ni	2.04	0.58
Totals	100.00	100.00

Figure 24: Deposits near torque transmission features on a power turbine from Red Deer River C/S (Alberta). [54]



16212-10

Element	Weight%	Weight% Sigma	Atomic%
C	2.00	0.42	3.65
O	44.05	0.34	60.31
Na	5.39	0.10	5.13
Mg	0.66	0.02	0.60
Al	2.59	0.06	2.10
Si	21.88	0.17	17.07
S	4.43	0.07	3.03
Ca	4.11	0.06	2.25
Ti	0.86	0.05	0.39
Cr	3.11	0.07	1.31
Fe	4.76	0.10	1.87
Co	1.90	0.09	0.71
Ni	4.26	0.11	1.59
Totals	100.00		100.00

16212-6

Element	Weight%	Weight% Sigma	Atomic%
C	3.73	1.25	6.95
O	43.36	0.69	60.58
Na	3.33	0.11	3.24
Mg	0.32	0.02	0.30
Si	0.15	0.03	0.12
P	1.62	0.06	1.17
S	17.99	0.28	12.54
K	1.57	0.05	0.90
Ca	19.09	0.30	10.65
Cr	0.61	0.06	0.26
Mn	5.90	0.14	2.40
Fe	1.34	0.09	0.54
Ni	0.47	0.08	0.18
Cu	0.52	0.10	0.18
Totals	100.00		100.00

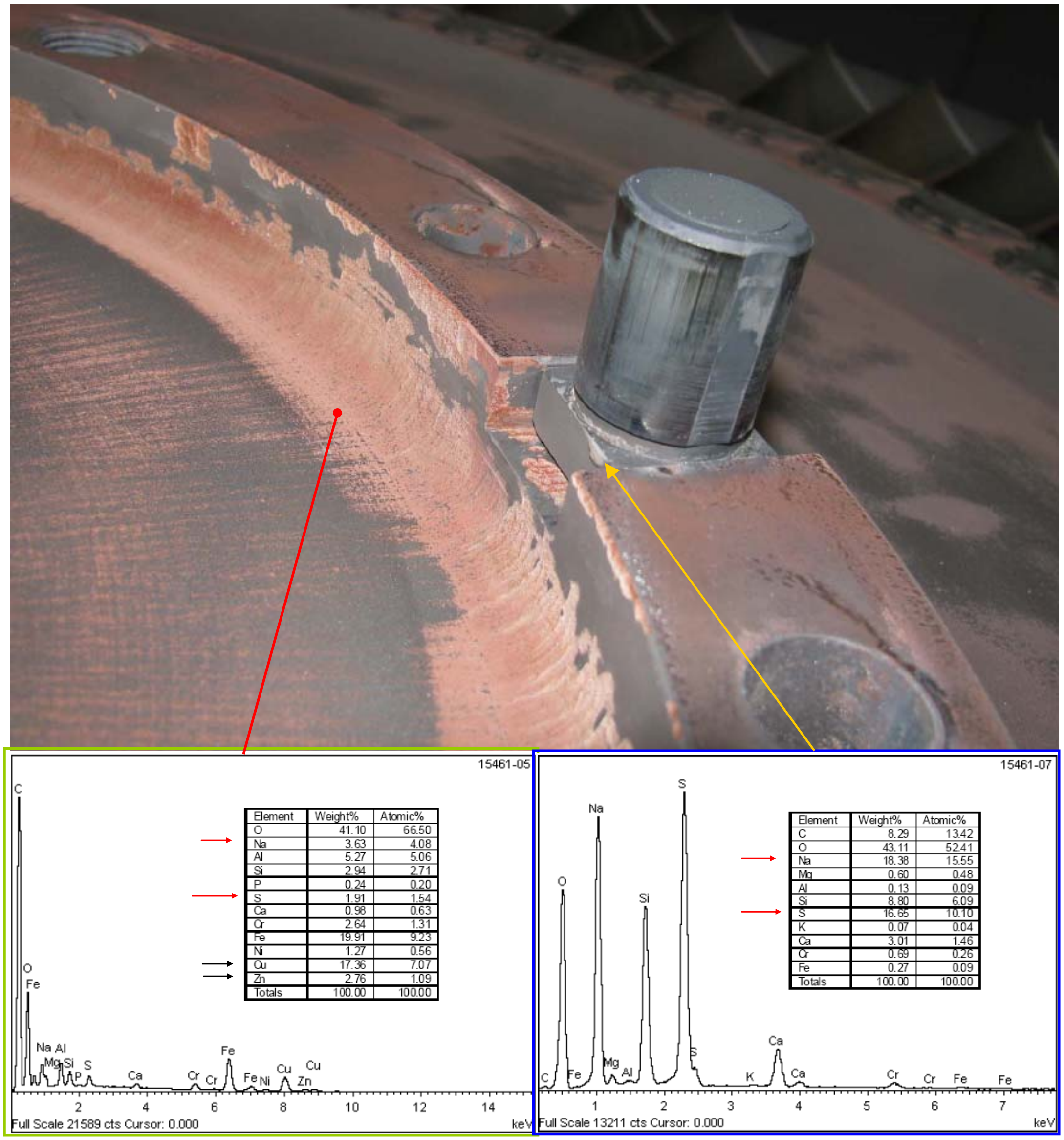
16212-4

Element	Weight%	Weight% Sigma	Atomic%
C	32.35	1.03	48.52
O	31.05	0.57	34.97
Na	2.26	0.09	1.77
Mg	0.26	0.02	0.19
Al	1.99	0.05	1.33
Si	7.24	0.13	4.65
P	0.05	0.03	0.03
S	2.29	0.05	1.29
K	0.07	0.02	0.03
Ca	1.34	0.04	0.60
Ti	0.13	0.03	0.05
Cr	1.73	0.06	0.60
Mn	0.10	0.04	0.03
Fe	6.36	0.13	2.05
Ni	11.74	0.23	3.60
Zn	1.04	0.10	0.29
Totals	100.00		100.00

16464-17B

Element	Weight%	Weight% Sigma	Atomic%
C	11.02	1.16	18.09
O	44.27	0.67	54.55
Na	1.16	0.08	0.99
Mg	1.65	0.04	1.34
Al	12.18	0.19	8.90
Si	5.52	0.10	3.88
P	5.99	0.12	3.81
S	4.24	0.09	2.61
K	0.62	0.04	0.31
Ca	6.14	0.11	3.02
Ti	0.47	0.04	0.19
Cr	0.59	0.05	0.22
Mn	0.34	0.05	0.12
Fe	2.14	0.08	0.76
Co	0.79	0.07	0.26
Ni	2.10	0.09	0.71
Cu	0.21	0.08	0.07
Zn	0.57	0.10	0.17
Totals	100.00		100.00

Figure 25: Analysis of deposits from a power turbine from Acme C/S (Alberta). [55]



Element	Weight%	Atomic%
O	41.10	66.50
Na	3.63	4.08
Al	5.27	5.06
Si	2.94	2.71
P	0.24	0.20
S	1.91	1.54
Ca	0.98	0.63
Cr	2.64	1.31
Fe	19.91	9.23
Ni	1.27	0.56
Cu	17.36	7.07
Zn	2.76	1.09
Totals	100.00	100.00

Element	Weight%	Atomic%
C	8.29	13.42
O	43.11	52.41
Na	18.38	15.55
Mg	0.60	0.48
Al	0.13	0.09
Si	8.80	6.09
S	16.65	10.10
K	0.07	0.04
Ca	3.01	1.46
Cr	0.69	0.26
Fe	0.27	0.09
Totals	100.00	100.00

Figure 26 – Deposits and analysis from a PT from Berland River C/S (Alberta). [56]

6 Mitigation & Remediation

With the advent of this problem, to be certain, TransCanada has had to manage this situation without disrupting operations. The following are some of the measures that were taken to reduce risk, in addition of course to maintaining a close relationship with the OEM and sharing information and being involved in the investigations.

6.1 Overhaul Schedules

All sites were reviewed for maintenance history and any possible common factors to sites or rotors that had been problematic. This included reviews of vibration trends, overhaul records, chronological factoring, whereby a matrix was established. Sites were ranked and selected for overhaul or inspection based on these results. Needless to say, shop arisings increased dramatically. Available disc material alloy and design upgrades are also being made at attrition opportunities.

6.2 Development of In-Situ Inspection

In order to help understand the scope of the problems, a decision was made to develop a procedure to allow the rotor stator cavity in question to be inspected. This was useful in helping rationalize how units were ultimately prioritized. The intent of the boroscope inspection was to identify if any major cracks or issues that already existed, recognizing the limitations of such a visual, endoscopic inspection technique, but it was deemed nonetheless better to look than to not. Once suitably sized equipment (3.9 mm diameter GE VIT unit) was received, inspections were carried out by manually turning the rotor while accessing the cavity through the second stage rotor blades. This required some patience. In addition to cracking, evidence of unusual corrosion or rubs were being looked for. The method proved successful as a cracked disc situation with some corrosion scale was actually identified via boroscope (Fig. 27).

6.3 Control of Assembly Lubricants

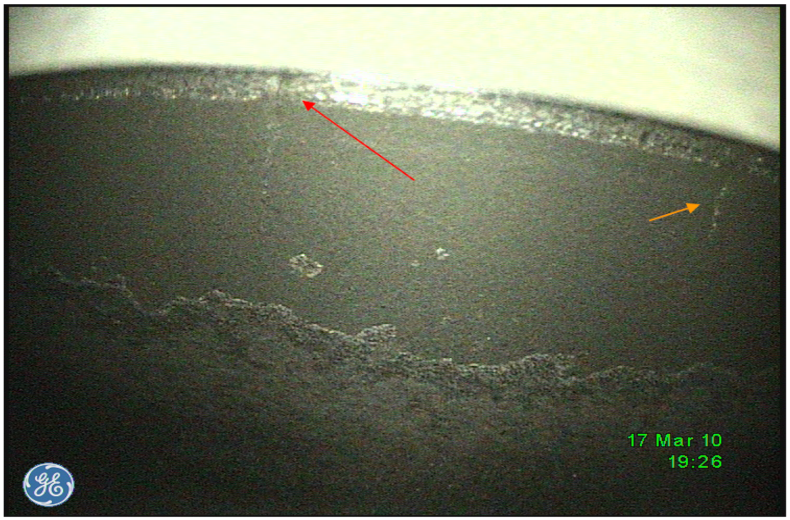
In is re-iterated here that, in respect to build lubricants (anti-seize), certainly the equipment OEM needs to specify and be consulted for guidance but the operator should remain diligent and ensure that a quality program ensures only approved high-temperature compounds and prescribed fluids are used (shop, build, balancing, manipulation and install). Equally critical is that adequate controlled instructions and a training regimen exists to ensure that such compounds are applied only in specified locations and that care is taken to ensure spill and unnecessary superfluous application is avoided. It is noted that sometimes product literature may overstate or have a lack of clarity as to the product capabilities for some applications.

6.4 Condition Assessments and Implications for Life Extension Strategy

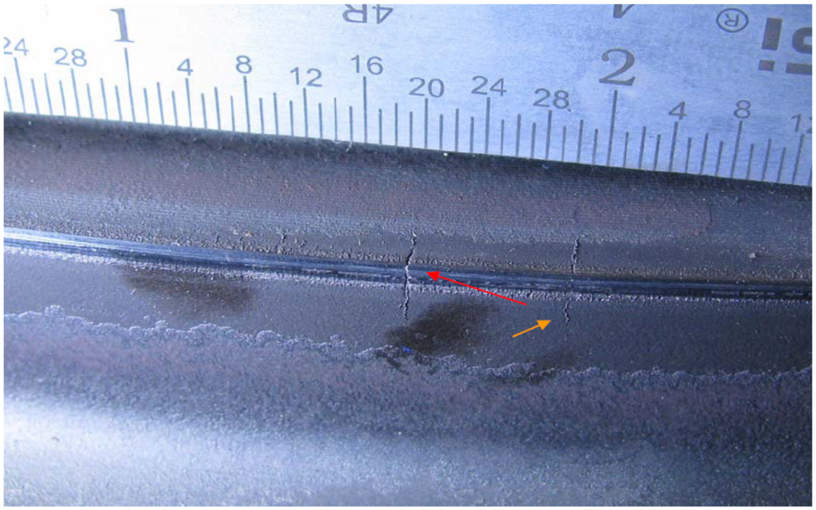
Practical Analytical and Prognostic life extension strategies, as described by Klova and Galatis or Koul, for discs still have their place and TransCanada remain a proponent of the concepts. [57, 58] However these experiences here documented underscore the importance of assessing corrosion and not only at the rim area. Corrosion and pits in areas of high stress may evolve into rather sinister threats and must be treated as such. It must be said that the findings in respect to level of problematic airborne salt impurities in the Prairies were somewhat unexpected, given a long experience with gas path components (nozzle and turbine blades) not featuring traditionally expected hot corrosion.

When equipment is being overhauled, this represents a period of time when much can be learned about the equipment but also its operating environment. Augmentation of NDE and diligence may be warranted for rubs or unusual conditions and an operator should not hesitate to seek counsel of knowledgeable experts.

In respect to power turbine maintenance intervals, a consideration is that power turbines have now evolved to a point where they are installed and can run through to original design lives in a single interval (100000 hours of operation, assuming not a cycling unit duty) with a minimum of maintenance and without removal. This is quite an achievement and reflects the good engineering design of these rotors. However, it can be a “backhanded” success story as well. In the twelve to twenty years it can take to accrue those 100000 hours, several undesireable episodes or “sins” (wash fluid carry over, filtration breaches, etc.) can occur and accumulate. When the effects are left to persist for such a long timeframe, corrosion has a good chance of reaching a point where its effects are too pronounced to consider continued use. Had such a rotor been periodically disassembled, inspected and cleaned, the outcome may be different at this point. Power turbine removals are intrusive to operations, time consuming, and expensive. So too are disc and blade replacements that may be avoidable. Neither, however, compare to the potential cost and safety consequence of a failure of equipment of this type.



Case 1 - Boroscope Image – 1003170127.jpg; Was estimated at 3/16” at time.



Case 1 - Indication near T-Pin Slot B – left hand later confirmed by UT.

Figure 27 – Small disc cracks identified via boroscope.

6.5 Filtration Considerations

While it would be easy to place all this on the inlet filters, there are some circumstances that must be borne in mind.

- Historically there have been documented periodic breaching of filter integrity due to a manufacturing issue with some filters (which were rapidly corrected).
- The fact of the matter is that the inlet systems, like the gas turbines, are reaching the end of their design lives. Seals, gaskets, door isolation, paint in many cases are in need of audit and remedy. Leaks allow filters to be defeated and condensation can become ice-hazards in icing conditions, while deterioration of paint can become a source on contaminants (zinc) for the equipment. [59]
- Water soluble salts that are trapped on filter elements can deliquesce and pass through as concentrated brine in periods of elevated humidity. This can occur when the relative humidity rises above 70%, and may not re-precipitate until humidity falls below 43%. [60]
- There have indeed been successes with the application of HEPA filters (including at TCPL's Grandview Power Plant) and many of these claim to be effective barriers to salts. [59, 61] However, to make such an investment without having addressed any other inlet "system" issues would not resolve the problem. HEPA filters would cut down the fouling and hence the number of soak washes required. Hence a second benefit to performance is a limit to opportunities for migration of contaminates.

One problem here appears to be that the limno-geological reality of the mineral makeup of the lakes and basins in the Western Canadian prairies has been under-appreciated. In fairness, information regarding the unique features of this area environment may not have been readily available in the time that much of the equipment and inlet systems were specified. Nonetheless, this situation underlines the importance of conducting proper siting studies with knowledgeable personnel when planning new facilities. OEM's and GE Energy's GER-4253 and GMRC/SWRI "Guideline for Gas Turbine Inlet Systems" are useful resources that should be consulted as they identify many of the issues documented as potential issues that need to be investigated before equipment begins being assembled at site. [60, 62] It also bears mention that sites and neighboring activities and surroundings are fluid: there may be a need to periodically assess changes in agricultural, industrial, power generation activities as well as road use to stay ahead of possible problems.

6.6 Future Work

Some projects TransCanada is considering or working on to bring closure to some of these issues.

- Detailed Disc Corrosion Characterisation.
- Disc Alloy Corrosion Susceptibility Study for those Alloys identified in Table 1.

- Long Term Inlet Air Contaminant Study in the Sour Gas Corridor to attempt to understand the fate of both SO_2 and sulphates from Sour Gas Processing and Upstream Oil and Gas Activity.
- Modification to Site Planning and Inlet Air Filtration System Selection procedures as well as the launch of an inlet system audit and remedy program. Once completed, filtration system modifications need to be considered to better protect for salt penetration and may include a move to HEPA or a return to multi-stage filtration in threatened regions – a cost benefit will decide.
- Adherence to compressor wash procedures: It is important to rigidly follow the procedures and protocols with respect to speeds when fluids should be admitted and correct nozzle pressures and flows to limit axial velocity and carry-over into the hot section as much as possible. Of course, water must also be known to meet cleanliness of the OEM specifications (demineralised).
- There is also some thought to consider a post compressor-wash Power Turbine Rotor-Stator Cavity Deluge Rinse with de-mineralised water.

7 Summary Remarks

The nature of the corrosion experience on some TransCanada Power Turbines has been reviewed. Sources of sulfur to feed and support the necessary reactions have also been presented. The unique geology of the Western Canadian (and upper US) prairies have been identified as a source of harmful contamination affecting the useable life of expensive power turbine discs. Depending on the elusive understanding of the fate of SO2 and aerosol sulphates emitted from sour gas processing and flaring, there may also be a link to contaminants introduced as a consequence of upstream oil and gas activity in the “Sour Gas Corridor” of Alberta. Thirdly, some evidence has been encountered that contamination by inappropriate assembly lubricants can also play a role. Fuel gas sulphur levels are shown to be an unlikely direct contributor in these cases. Nonetheless, the admission of thernadite and other sulphates through the inlet and its migration through compressor washes explain why the gas path components appear relatively unaffected, whilst low flow secondary air systems and cavities where concentrated deposits persist for long times are. The consequential resultant corrosion observed, and its evolution to cracking in stressed areas, represent significant integrity threats for equipment in this theater. Alloys of construction and inlet filtration system design and upkeep will likely have a bearing on which types of equipment are most susceptible. Some practical considerations to mitigating some of these occurrences have been offered. It is hoped that for any who might operate equipment of this type in these theaters and were unaware, the information contained herein will help acquaint them with the perils of salt corrosion, even substantial distances from the oceans.

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