MANAGEMENT OF GEOTHERMAL TURBINES AS PRESSURE EQUIPMENT

Chris Morris

Wairakei Power Station PB2001, Taupo 3352, New Zealand

chris.morris@contactenergy.co.nz

Keywords: *Geothermal Turbine, PECPR, O&M.*

ABSTRACT

Contact Energy Geothermal Group based at Wairakei operates 16 geothermal turbine generators from seven different manufacturers. Most are steam powered but four are pentane binary cycle. It also has some turbines mothballed, but able to be overhauled, then returned to service if needed. The operations and maintenance of the equipment, some from manufacturers that no longer exist, means that keeping the plant within the requirements of the PECPR regulations is not an easy task. This is not helped by legislation and statutory requirements that are vague and do not adequately recognise the true risks. Practices and a system have been developed to comply with the rules and that allow self-management of the pressure equipment.

1. LEGISLATION

The only mention of steam turbines in PECPR Regulations is the definitions; saying they are pressure equipment.

> **pressure equipment** means a boiler, boiler piping, compressor, fired heater, gas turbine, hot water boiler, piping component, pressure fittings, pressure piping, pressure vessel, pump, steam engine, or steam turbine

There is an Approved Code of Practice (ACoP) for Pressure Equipment that includes turbines. Within this, there is a dedicated section 7 for steam turbines, but this doesn't give much information on what is required to operate and maintain them. It falls back on the generic pressure equipment O&M information, having qualified people to operate and maintain the plant, develop procedures that are regularly reviewed and keep records. It has this about safety devices:

> (5) Safety devices shall be operable whenever equipment is used. All tests of emergency procedures, alarms, safety trips, and other safety devices, relating to equipment, shall be performed as recommended in the operating manuals for the equipment or in accordance with the standards of generally accepted industry practice. Where appropriate, testing shall be witnessed and approved by an inspection body.

The ACoP section for turbines, like the rest of the document, is not definitive – it uses a lot of "recommendations of the manufacturer and the standards of generally accepted industry practice". This is in sharp contrast with ACoP (boilers) that is very prescriptive.

The ACoP recognises AS/NZS 3788 as the way to determine the in-service inspection frequency. There is also guidance in the standard on assessing defects and maintenance practices on pressure relief equipment. Turbines aren't mentioned specifically in AS/NZS 3788, apart from the following note.

> AS/NZS 3788:2006 6
>
> This Standard does not specifically deal with the following equipment, but provides information which may be used as guidance.
>
> (i) Storage tanks covered by AS 1940 and built to API 650, AS 1692 or equivalent (refer API 653).
>
> (ii) Miniature boilers to the AMBSC codes.
>
> (iii) Pressurized machines, e.g. turbines, compressors, etc.
>
> (iv) Pipelines as per AS 2885 or equivalent.

So the Regulation, ACoP and reference standard give no firm guidance on what needs to be done to operate and maintain the plant safely. It is left to the operator themselves, using the manufacturer's manuals and the vague "generally accepted industry practice". For geothermal turbines, Contact and its predecessors at Wairakei has been involved since the beginning, so many of our experiences have become the defining practices.

An important step in the maintenance requirements evaluation process is assigning a Hazard Level to the pressure vessel using AS 4343. Unfortunately, there is no mention in the standard of how to assess turbines which can be high pressure at the inlet and not a pressure vessel in the exhaust. The only mention of the word "turbine" is in the Foreword where there is this passage:

> **WHY WAS THIS STANDARD NEEDED?**
>
> In 1978, the late Alex Wilson AM, Chief Metallurgist, Electricity Commission of NSW, asked a new Chief Inspector of Boilers to clarify the law that required Government design approval, manufacturing inspection, registration and in-service inspection by government or licensed Inspectors, for a 30 L × 1 MPa air receiver, but did not require this for 660 MW, 16 MPa high-temperature steam turbine, which was potentially far more hazardous.

From the actual wording of this standard, we can only assume that the standard writers decided to assign the same Hazard Level to the turbine as that of the equipment that supplied the steam. This is not explicit though. It is also of no help to geothermal turbine operators as the wells are covered by a separate piece of legislation. There is no definition of the turbine boundaries. Is it the front flange of the steam strainers, the stop valves or the flange where the valves bolt to the turbine casings (Figure 1)? The back end of condensing turbines, particularly those with barometric legs, aren't even pressure vessels. Contact Geothermal has addressed this lack of clarity by coming to an agreement with SGS that we arbitrarily assigned our turbines Hazard Level "B". The ticket includes all the valves and casings with an arbitrary boundary at the join between turbine and condenser. The pipe bringing steam to the turbine doesn't have a specific ticket, but is covered in the generic steam piping.

There is no guidance from any of the legislative documentation about what is seen as critical (like integrity of rotating components) in a turbine, other than the generic pressure vessel issues.

1.1 Pressure Protection

Because turbines aren't steam raising, they generally have no pressure protection devices on the inlets. Instead, they rely on the protection on the boiler or manifold that they get the steam from. The turbines can have load limiting devices, but these are to prevent over-rating of the output as the inlet pressure is an easily monitored proxy for load.

For the turbine outlet pressure protection, a lot depends on whether it is a back pressure machine, where the steam goes to another use, or if it is a condensing turbine. For the former, there is generally a safety valve. This is managed as per AS/ NZS3788 Section 4.7. Our machines also have trips if the exhaust valves aren't full open. Condensing turbines normally have bursting discs fitted on the exhaust casing. This is in addition to the poor vacuum trip protection. If the turbine condenser has a barometric leg, it doesn't need exhaust casing overpressure protection but some machines have them fitted – the belt and braces approach to plant safety.

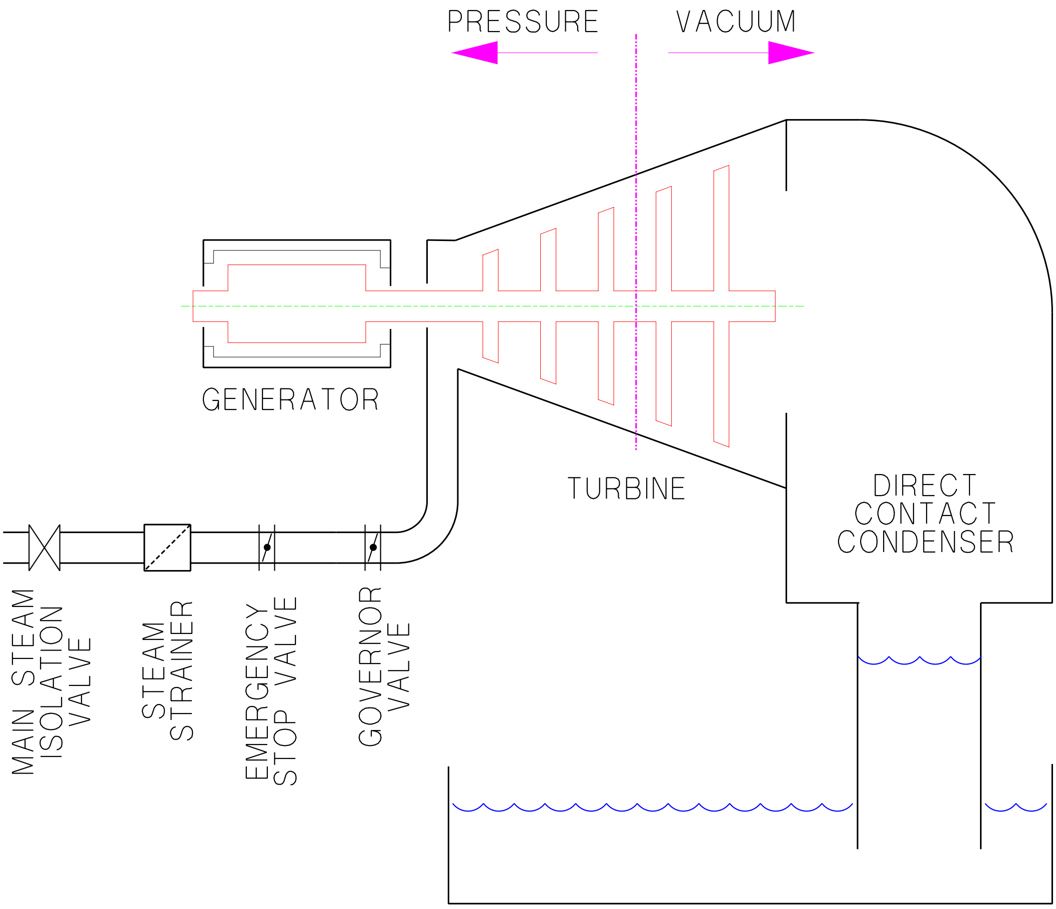

Figure 1 A common geothermal turbine configuration. Where are the pressure vessel boundaries of the turbine?

2. PUTTING THE LEGISLATIVE REQUIREMENTS INTO THE WORKPLACE

Because of the large number of pressure vessels Geothermal Group has (~300), and our ISO 9001 certification, we self-manage our pressure vessels' inspection. SGS are our third party inspectors. The critical part of our self-management is that we have comprehensive documentation in place, covering all the necessary aspects, and which can be audited.

Contact Energy follows best practice in its workplace health and safety practices. There is an overarching company policy that deals with compliance with the rules. Sites then develop documents on how they will meet the requirements of the policies. This includes all the procedures and checksheets to detail the work methods and leave a document trail. There are annual internal and 3rd party audits to ensure that the system is working and no gaps are occurring. The important review for turbines is the external AS/ NZS3788 audit.

There is an Overall Inspection and Test Programme (OITP) for all the pressure vessels. This sets the inspection intervals and is formally reviewed with the 3rd party inspector yearly. As well as the set interval, there is also risk based assessment that determines the inspection's work requirements.

The most important part of the plan was the risk assessment. This was developed by several of the site engineers, using their own knowledge and experience, plus the OEM's O&M manuals and specialist reference books. The initial step of the assessment was to determine the damage mechanisms and the affected regions. From this, the consequences and likelihood of unmitigated operation were then determined. The risk rating of the damage was assigned from the company Criticality Assessment Risk Matrix, which was developed from the ISO 31000 standards. The document was then circulated internally for comment and the revised document put into the system.

The major risks on turbines are not associated with pressure containment but from the rotational energy. The biggest risk was seen as overspeed, followed by stress corrosion cracking or high cycle fatigue in the rotating components. Bearing failure and loss of lubrication oil were rated just below that. Generator endring failure was not included in the risk assessment as they were seen as outside the pressure containment envelope. However, it was covered by other management policies. If the endrings had been included in the turbine analysis, they would have been the second or third highest risk.

Once the risks had been detailed and assessed, then a mitigation practice could be developed for each one. This was then integrated into the operations and maintenance management plan. For some it is work practices, procedures and skills of staff. Some called for NDT work done by specialised contractors. Others needed checksheets so there was a written record of measurements and values. For much of the above, there was subsequent analysis of the data, by staff engineers or consultants and reported. These would be in a feedback so that future practices were modified to take changes into account.

Contact’s experience has been that the manufacturer is not necessarily the best source for operations and maintenance advice. A case in point in the failure of high tensile steels in geothermal steam from Sulphide Stress Corrosion cracking. This is a well know phenomenon and most design contracts specify compliance with the materials listed in the Sour Gas standard (ISO 15156) to reduce the risk. Turbines are still being manufactured with hard steel, hence failure prone, components in the steam path. It is relatively easy to change out bolting when it is found (assuming it hasn’t broken and done consequential damage), but this is a lot harder for turbine blading.

2.1 Generators

As well as the turbines, Contact has one hydrogen cooled generator. This is also a pressure vessel. The plant was originally built for California but never installed there. Some years after it started operation, it was noted that there was no certificate of inspection for the generator. That meant obtaining retrospective certification. It was not an easy task assembling all the documentation to show that the machine met the relevant New Zealand codes and standards applicable at the time.

3 MITIGATION OF RISK PRACTICES

3.1 Operations

Geothermal turbines are baseload plant. This means that the risk profile is different to that for plant which is regularly stopped and started. With the valves fully open for long periods, it means that there are routines for control and stop valve stroking. These cause short period load losses. They are very high priority tasks for operations staff to do, as they are the main protection against machine overspeeds. If the valves feel sticky (deposition or corrosion on the valve components is a real problem) or are not functioning correctly, the unit is taken out of service, the valve inspected, then retested. For those plant with mechanical or hydraulic overspeed devices, these have regular simulated tests to check they function correctly. There are walk-arounds of the plant at least once a shift by operations staff, which often pick up incipient faults like leaks developing.

When the machine is taken out of service for maintenance, the vibration reading from the hot rundown may be recorded with specialised loggers. This data can be analysed to give valuable information about balance, alignment and even the bearing clearances. Generally, the run up is also logged, but less priority is put on this data.

There are routines for oil and steam samples for analysis. Though many boiler plants have steam conditions continuously monitored, it isn’t that common for geothermal turbines. Grab samples don’t give good reproducible data. This lack of monitoring is despite the steam purity being worse and the steam carrying significant quantities of water. There is no suitable equipment or even a standard on acceptable steam purity or quality for geothermal turbines. Work is being done through the local branch of IAPWS (International Association for the Properties of Water and Steam) to both implement a monitoring regime using equipment that will give meaningful results, and developing a suitable standard. Until then, steam monitoring is not a satisfactory situation, but it is work in progress. The contaminated steam causes deposition in the nozzles (lowering the output) and can give both corrosion and erosion damage.

The operators set their adjustable alarm limits on many different operating parameters just outside normal operating range. This brings changes to their attention, even if the plant is still operating well with the protection trip, or even alarm, limits. It allows potential issues to be investigated early, either by operations staff or the engineers. This is where the historian system logging the readings and events proves invaluable as long term trends can be determined, as well as allowing possible influences on step changes to be investigated. If there is a non-spurious tripping of a unit by a protection device, then the plant cannot be returned to service until it has been investigated and signed off by the relevant engineer.

3.2 Overspeeds

This is the single biggest risk to turbines. All the plant has electronic overspeed equipment but most have a spring loaded eccentric bolt to supplement this. Together with the routine mechanism testing described above, physical overspeeds are done on an annual basis. They are also done on return to service after a survey, or when any work on the mechanism has been done. When the generator endrings have been removed, two overspeeds are done to ensure the rings are bedded. On modern machines, overspeeds can be done from the control room, but for the old plant, it is a manual procedure from the turbine floor.

Policy is to do overspeeds on heat-soaked machines. To allow this to be done on a rebuilt machine with mechanical devices, the electronic overspeed is tested at below operating speed. It is then set to 111% plus 1rpm, as most devices are supposed to trigger at 110±1%. The machine is run up, synchronised and loaded up to above half load for at least four hours. There will generally be an operator in attendance. It is then taken off the grid and an overspeed done. Assuming the mechanical device operates correctly at an acceptable speed, the electronic setting is changed back to 110%, and the machine released for unrestricted operation.

3.3 Instrumentation and Protection

Instrumentation and protection on the machines is supposed to be the European Standard BS EN 60045-1 from the ACoP as well as from the Pressure Equipment rules. The requirements are rather generic, but sensible for long term asset management. It should be noted that the referenced standard is a procurement guide, not a design or operation standard.

Because some of our machines date back to the 50s, the OEM supplied instrumentation is not adequate to meet today's requirements. This has meant extensive retrofitting and uprating of the equipment to modern standards. It is all "failsafe", tripping the machine on "not OK" and has the appropriate Safety Integrity Level (SIL) rating. The actual protection is generally hardwired switches, not a PLC acting on a transmitter's signal. Protection wiring is colour coded so all staff are aware of its function.

During instrumentation and protection upgrades, the logic of some of the trips were changed. If the generator trips, the circuitbreaker won't open until the ESVs have shut. This is to keep the machine locked onto the grid until the steam has been shut off. Better to motor a generator, trashing the rotor endrings, than risk a machine overspeed.

Calibration of the protection equipment is controlled by an ISO 9001 process with regular audits. All the calibration information is kept in a protected database. Changes to any settings go through a Management of Change process and need to be signed off by the appropriate engineering level.

When recommissioning a machine after an outage, all protection devices and trip functions and essential services like oil pump cut-ins are tested and proven before the machine is rolled. The return to service after a major outage, especially if plant modifications have been done, is covered by a written procedure with signoffs by the overhaul staff and acceptance by Operations.

3.4 Surveys/ Internal Inspections

The most important part of the pressure equipment management is the internal inspections. The underlying principle behind the inspection interval is that the machine should be safe until the end of the period taking into account the risk assessments. AS/ NZS3788 gives no guidance on the frequency for turbines. We generally do them at five yearly intervals after they have gone through 1, 2 and 4 year gaps between inspections. This means that the vessels' surveys are not always synchronised with the maximum interval of 4 yearly inspections for steamfield pipelines. Because of the demand on often very limited resources, it can be advantageous to have steamfield surveys at different times to the turbines' ones. However, where there are underlying faults or potential issues on plant, the inspection interval is shortened or an out of sequence one done.

The machines are generally taken down to bare turbine casings with all the furniture out. At the same time, the ancillary plant can also be overhauled, though this may be left to outside survey if there is redundancy. Work done during turbine surveys can be split into four areas:

- Dismantle and clean,
- inspect/ dimension/ calibrate,
- repair/ refurbish/ replace,
- rebuild.

All of these tasks need significant supervisory and engineering input. Much of the information provided by OEM is incomplete. This needs people who know both the plant and the workstream process to make the numerous work process decisions. There is also the requirement for specialist contractors, especially NDT services.

A critical part of the inspection process is the checksheets. These were developed so there was a written record for the components seen as important. An essential part of them was documented acceptance criteria. These were generally taken from the manufacturer's information. In some cases, they were modified from experience. We also require the original for the records, oily fingerprints, marginalia, dog ears and all. The risk of transcription error is just too great for the information they contain. There are also written procedures for complex, high risk or critical tasks.

On opening, the internal components of geothermal turbines are generally coated with a thick layer of magnetite with pyrite often present. This can cause rust if exposed to moisture. If the magnetite is not present, it is because the steam is too wet to allow it to form. There will also be gasketing and jointing material on the sealing faces. Before NDT of components can be done, surfaces need cleaning. Industry practice is to use UHP (Ultra High Pressure) water, soda, dry ice or even walnut shell blasting. Contact uses UHP water for almost all its major component cleaning with glass bead blasting of the smaller parts. Grit isn't used because it erodes parent material away. If coated in magnetite, the casing generally isn't cleaned.

Boiler plant is different because of superheat, but geothermal turbines are almost totally operating below the steam saturation line. This means that water erosion/ corrosion is the main damage process. This is exacerbated by poor assembly, but even in ideal conditions, it cannot be eliminated. The steam purity on geothermal plant is often not good, so both scaling and chloride induced corrosion are common. As earlier discussed, geothermal plant can't use high strength materials in the steam path because of SSC cracking, so use of erosion/ corrosion resistant material is restricted. That means there is often a need to do repairs or part replacement of many internal components. However, as even the highest operating pressure geothermal turbine has steam inlet temperatures under 250°C, creep and high temperature distortion aren't issues.

The casings on geothermal turbines are nowadays fabricated steel, but older ones often were cast iron. The latter is generally corrosion resistant but prone to steam cutting. Contact also had some replacement casings made out of stainless iron 25 years ago which are still in as-new condition. The casings are generally significantly thicker than needed for pressure containment. The sections most prone to damage are the halfjoints, between stages or the diaphragm sealing faces. These can be repaired by welding or ceramic fillers. The stay bars used to internally stiffen casings can also be very prone to corrosion/ erosion from water droplets in the steam. These are d-metered in the eroded sections and replaced as necessary. Almost all the work is like for like replacement or repair.

Modern monobloc turbine rotors are generally trouble free, bar for cracking around blade roots, but larger rotors can have shrunk on discs. These are prone to cracking around the keyway, especially if the steam is not clean. Specialised ultrasonic NDT has been developed for inspection but indication characterisation is generally not definitive because they haven't grown enough to positively identify. There is something there, but we don't know what it is or even if it is serious. Not conducive to peace of mind for the engineers! Old rotors often had inclusions or defects in the forgings that were not detected by the rudimentary NDT of the time. If the rotor has a central borehole, then testing at half-life refurbishment can give assurance on the integrity.

Crack detection in the diaphragm vanes and turbine blades is usually done by MPI with dye penetrant as a secondary confirmation. The diaphragm vanes are prone to cracking from high cycle fatigue vibration flutter. These are easily identified and repair is not difficult. Doing the rotating blade aerofoils is relatively easy, but the blade root inspection can be impossible. Here, one often has to rely on industry experience on risk identification and grading. For defects like the fir tree root blocks, there isn't a viable NDT method of detection with the blades in situ. That is where risk management is needed.

The valves are generally dismantled enough so shafts and sealing surfaces can be inspected. Bearings and shaft seals are replaced as necessary. Actuators are usually hydraulic against a spring – a very reliable system - so not worked on unless there has been concerns about their action.

Bearing condition is assessed by a combination of visual inspection, dimensioning, dye penetrant and d-metering. The latter can identify disbond between the white metal and the steel body. The historical records are also important as bearings can be outside acceptance criteria but not changing. In these cases, they can generally go back in service.

Even though they are not part of the pressure envelope, the generator endrings are now regarded as a critical turbine/ generator component. They are invariably the highest stressed parts on a machine, and in an overspeed, often the first to fail. The rings are also prone to stress corrosion cracking growing from any arc pitting or other stress raisers. This cracking can mean they fail under normal operating conditions. When the rings let go, it is catastrophic, destroying the machine beyond economic repair. Any staff in the vicinity are at high risk of injury or death. A low probability, very high consequence event! Following international good practice, Contact now removes the endrings every second survey for internal NDT. If asynchronous motoring of the generator during an event is even suspected, then the plant is taken out of service and rings removed for inspection. Recent work has identified that variable speed drives taking their power from the generator side of the transformer may cause arc pitting on the rings, so that needs to be considered in determining inspection intervals.

3.5 Out of Service Storage

It has been found that significant corrosion can occur whenever machines are taken off -line. This is because the steam isolators often don't seal completely. The combination of moisture and air can turn the pyrite to sulphuric acid that rapidly attacked the steel. Normally, machines are opened up as the outage is to allow maintenance. This allows the moisture to be eliminated by dilution with the warm dry air within station. If this is not possible, then there are two actions taken. The first is to keep the machine running at minimum revs. That keeps it available for service. This is what is done if the outage is for a relatively short period.

If the off-line is for to be for more than a fortnight, or a semi-permanent mothballing, then the machine is shut down. The isolators are hardened down. The machine then has ports opened up to fit a dehumidifier as soon as possible. Valves are chocked partially open. The inspection hatches into the condenser are opened. Warm dry air is then pumped into the plant. The circulating air dries out any remaining moisture. Industry experience is that once the air gets below 30% relative humidity, then any exposed steel won't corrode. The oil pumps are regularly started and the machine put on barring (if it is fitted) for about an hour a week. Preserved in this state, the machine doesn't deteriorate. It can also be returned to service within several days if needed.

4 PENTANE TURBINES

The turbines on pentane cycle binary plants are significantly different to steam turbines. Their construction is more comparable to a pump, where the shaft is on rolling element bearings carried in a separate housing. They have a mechanical seal rather than glands to keep the working fluid in the casing and away from the bearings. The assembly is more like a multistage pump, where the moving blade discs are clamped on the shaft as it is assembled with the blading rings separating each disc attached to the casing.

The thermodynamic properties of pentane are such that the vapour goes into superheat as it expands through the turbine. This, and the absence of either water or air, means that corrosion/ erosion wash is not a viable damage mechanism. Even after 10 years operation, the welding in exhaust casings look like new.

The pressure vessel "internal" inspection management strategy adopted has been ultrasonic thickness measurements of turbine casing points. This is in lieu of internal inspections. There are bearing & seal condition based overhauls. These generally have been at four to seven year intervals. To replace either the seal or the bearings means the turbine has to be fully disassembled. Inspection during this work has confirmed the NDT measurements; there has been no loss of metal on the pressure containing components.

Protection follows very similar principles to that on steam turbines. The valve actuator power is provided by compressed air rather than hydraulics, but the operation is the same. The emergency oil pumps are air rather than DC motors. Being rolling element rather than plain bearings, the vibration is by accelerometer but setting follow industry guidelines. There has been problem with protection switches failing (false positive trips) but these have been changed out for more reliable components. Position indicators on valves are being retrofitted to bring the older plant up to modern requirements.

5 THE FUTURE?

The Code of Practice covering turbines is over 15 years old. The Standards referenced have been superseded. There have been various drafts of an updated version floating around in the industry but nothing concrete has been sent out for comment. Plant protection has almost totally gone away from mechanical devices and switches, so the rules need to reflect this. If and when a new version of the code is drafted, it would be better if it was less prescriptive. Requirements should be more on risk based assessments, like those in VDMA 4315 and IEEE 122. Safety systems designed to IEC 61508/ 61511 or ANSI/ ISA S84 have clear design performance, and (from the design) proof testing intervals and procedures. These should be reflected in the O&M instructions and manuals for the equipment.

6 CONCLUSIONS

Though the legislative and manufacturers' documents give little guidance, Contact has been able to put in place full operation and maintenance practices for its turbines. This has allowed it to safe, reliable baseload operation of its plant for nearly 60 years, with much of the original componentry still in service.

7 ACKNOWLEDGEMENT

The author thanks Contact Energy for permission to publish this paper and his workmates for their comments.