Controlling Condensate & Feedwater Dissolved Oxygen & Air Inleakage At The Source

ROBERT D. BARTHOLOMEW, P.E.
GARY H. ROBERTS, P.E.

Sheppard T. Powell Associates, LLC (STPA)
Baltimore, Maryland

KEYWORDS: Condensate Treatment, Feedwater Treatment, Dissolved Oxygen, Air Inleakage

ABSTRACT: Low dissolved oxygen concentration limits in condensate systems and in many feedwater systems for heat recovery steam generator (HRSG) units or conventional boilers can be difficult to maintain. This paper summarizes the causes and presents methods of controlling sources of dissolved oxygen into these systems.

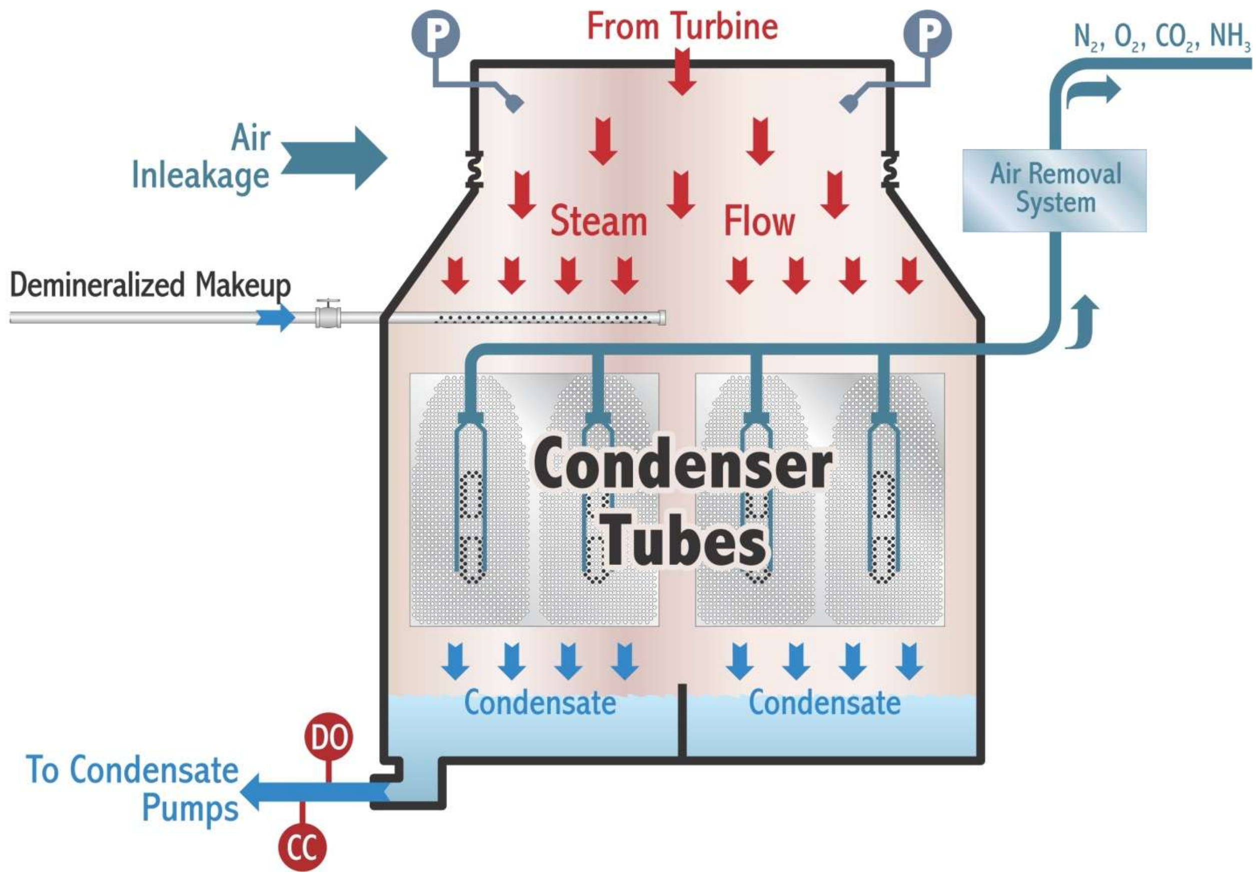
INTRODUCTION

Air is comprised of 20.9% by volume oxygen (23.1% by weight) and ~0.04% by volume of carbon dioxide. Air is the ultimate source of all dissolved oxygen contamination of the condensate and feedwater. Demineralized water in equilibrium with air can have ~8-14 ppm (~8,000-14,000 ppb) as O_2 of dissolved oxygen (DO) depending on the temperature - based on oxygen solubility.

Carbon dioxide has a higher solubility and it undergoes equilibrium reactions with water. Therefore, even though carbon dioxide is a small proportion of air, substantial amounts can be absorbed in water. Based on experience, cation conductivities due to carbon dioxide absorption from the air can reach ~0.8-1.0 µS/cm in demineralized makeup water. These conductivities theoretically correspond to about 0.50-0.75 ppm as CO_2 of total inorganic carbon or about 0.41-0.64 ppm as CO_2 of free carbon dioxide, which is in equilibrium with bicarbonate.

Figure 1 shows a simplistic view of a condenser. Steam from the turbine is condensed and leaves as condensate. This creates a vacuum. The vacuum draws air into the condenser through turbine seals and any crevice, fitting or leaking drain or vent valve on the connected equipment. Most of this air is withdrawn through the air removal system.

Figure 1 – Simplified Sketch of Condenser



A small amount of the dissolved oxygen and carbon dioxide will leave with the condensate as reflected by the condensate dissolved oxygen and cation conductivity, respectively.

Demineralized water, which is a source of dissolved oxygen and carbon dioxide, is applied through a distributor. Some condensers have well designed distributors that allow liberation of the entrained gases in the condenser. Many condensers have poor distributors, which allow the dissolved gases to pass into the condensate.

FINDING & MONITORING AIR INLEAKAGE

The following list presents the primary monitoring methods for indicating condenser air inleakage. The most definitive monitoring techniques are shown first followed by methods that can be more subject to interpretation.

- Direct Air Inleakage Testing.
- Air Removal Rates from Vacuum System (Actual amount removed).
- Increased Turbine Backpressure.
- Condensate Pump Discharge Cation Conductivity (from carbon dioxide absorbed from air in contact with condensing steam).
- Condensate Pump Discharge Dissolved Oxygen (from the oxygen in air or oxygen in the makeup).
- Water/Steam Leaks (Both Out-of-service and In-service)

DIRECT AIR INLEAKAGE TESTING

Table 1 presents a summary of the direct test methods for air inleakage testing [1-4].

Table 1 – Summary of Direct Air Inleakage Test Methods during Operation

Methods (1, 2)	Minimum Detectable Leakage Rate, Pa-m³/s (Ref. 1)	Use for Condenser Air Inleakage Surveys
Foam or Plastic Wrap	N/A	Used by some plants to find large leaks [App. E. of Ref. 4]
Bubbles	10^{-5}	Can find large leaks if you know and can access the locations.
Thermal Conductivity or Thermography	10^{-6}	Not common. A large vacuum leak is reported to cause a locally low temperature.
Tracer Gas - Helium	10^{-10} (Can detect 1000 ppb in air)	Standard method used by power plants. Reportedly can find leaks of 0.1-1.7 scfm [3]. Contractors will use this tracer gas if >10 scfm total air inleakage [4]
Tracer Gas - SF_6	10^{-12} (Can detect 0.1 ppb in air)	Currently mainly used by just contractors. Their standard tracer gas if total air inleakage is <10 scfm [4]

Reference 1 also mentioned ultrasonic testing, but the leak detection limit was reportedly several orders of magnitude larger than bubble test methods. Many plants have their own helium leak detection equipment and there are a number of contractors that can perform surveys using the more-sensitive sulfur hexafluoride (SF_6). Use of these tracer gases is considered best practice.

AIR REMOVAL RATE MONITORING

Meters

Meters can be used to measure the flow of noncondensable gases removed from the condenser [2-12]. The traditional monitor diverts the air removal equipment exhaust through a rotameter. If the leak exists on the vacuum system (e.g., on the vacuum pump suction flanges), then the rotameter will give false high readings. Online flow monitoring systems which monitor the off-gases before the vacuum pump or steam jet ejector are useful since they are not affected by vacuum leaks in the air removal equipment. A microprocessor-based or computer-based system is needed to account for the temperature, pressure and two substances (air and water vapor) which are present. Simply installing an orifice or a pitot tube and differential pressure monitoring equipment will not provide sufficient information.

While we have started to see some online orifice plate flow measurement in air removal systems, the most common online flow meter in air removal systems at our client's facilities is an analyzer (Rheovac by Intek) that measures the temperature, pressure, relative humidity, and flow rate using a thermister-based system. From this information, the analyzer provides the following parameters to characterize air inleakage:

- Total flow measured in cubic feet per minute (cfm)
- Air inleakage/removal rate (noncondensable gas flow rate) expressed in standard cfm (scfm)
- Water to Air Mass Ratio

The analyzer literature states that the water to air mass ratio should be kept greater than 3. This corresponds to a water-to-air mole ratio of 4.8, which means that the proportion of air (NCG) being extracted from the air removal zone is designed to be kept less than 17% by volume. This is fairly consistent with the Heat Exchange Institute guidelines which advises to keep the proportion of NCG to total gas flow rate at ≤0.15 of the total flow in the vacuum system to achieve <7 ppb of dissolved oxygen with 20-250 scfm of total venting capacity [9]. For example, the standard states that the maximum noncondensable gas flow is only 6 scfm for an air removal system with a total (steam and NCG) flow rate of 40 scfm in the vacuum system [9].

If the water to air mass ratio is not greater than 3, then an additional vacuum pump should be placed in service to draw more vapor into the air removal zone. Reference 10 provided an example of this sort of evaluation that found a problem with one of two vacuum pumps. It was normal practice to run with one of two pumps. This resulted in poor air removal, backpressure problems and an estimated cost of $36,000 Per Year in 2004 [10].

- Pump 1 - Water/Air Mass Ratio of ~2
- Pump 2 - Water/Air Mass Ratio of ~1
- Pumps 1 & 2 - Water/Air Mass Ratio of ~4.

Limits

While the traditional industry guide was 1 scfm/100 MW, a number of units have maintained condenser vacuum and normal steam/water cycle chemistry within industry limits without meeting this air inleakage target. A number of companies have found a more practical action limit for air inleakage to be ~2-3 scfm/100 MW. With an active air inleakage program, most plants can and should control air inleakage to obtain a total air removal rate below 3 scfm/100MW. For these estimates, the design load of the condenser is used. Plants that can achieve <1 scfm/100 MW should continue to do so.

The ASME performance test code for condensers raised the limit of acceptable air inleakage between the 1998 and 2010 versions of the standard [8]. It allows higher air removal rates for multishell condensers than for single shell condensers. Interestingly, we estimated the steam flow entering the condenser for a half dozen of our client's units and obtained allowable air inleakage rates from the HEI standard tables, which corresponded to 2-3 scfm/100 MW. Therefore, this appears to be an important threshold limit at which action is required.

Condensers can be redesigned to reduce air storage in the condenser and thereby allow higher air inleakage rates [16]. However, for most existing condensers, the PTC limits or <2-3 scfm/100 MW are suggested herein for use as operating targets.

During low load operation, the total flow rate of air usually will be noticeably higher than during full load (although we present an example of the reverse trend later). This increase in air inleakage at low turbine load is attributed partly to a greater proportion of the steam/water cycle being under a vacuum. Therefore, if many more components in the steam/water cycle are under a vacuum, higher air inleakage is expected. The limits indicated herein are based on the steaming rate at full load conditions.

Calibration Checks of Air Removal Rate Monitors

Often it is very difficult to find and fix air leaks. This can lead us to question whether to believe the air removal flow meter. The following is a simple test to demonstrate that the air removal flow meters are functional.

1. Find a tap connected to the hotwell (preferably above the water level) and connect an air flow meter (e.g., 0-10 scfm).
2. Notify the control room operator to record and watch the turbine backpressure and condensate pump discharge chemistry (dissolved oxygen and cation conductivity).

If you already have high air inleakage, it may not require much more to significantly affect these parameters.

3. Check the air removal meter readings for the air removal system from the condenser (also note the reported water to air mass ratio, if the analyzer indicates this ratio).
4. Open the new air tap by 5 scfm and repeat steps 2 and 3. If necessary due to the range on the flow meter, a different air flow rate can be selected
5. Close the new air tap and repeat steps 2 and 3.

This test tap also can be used to determine how close you are to the point of having problems with turbine backpressure and condensate pump discharge dissolved oxygen. The test would be repeated with incrementally higher levels of air inleakage. The test should be terminated within an hour of noticing increased in dissolved oxygen or cation conductivity.

Test Locations

Plants that perform their own air inleakage testing with Helium develop a list of test locations that should be targeted for evaluations. The references provide examples of suggested test locations. Table 2 provides a starting list of locations.

Table 2 – Starting List of Condenser Air Inleakage Test Locations

Turbine

- Rupture Disks
- LP Turbine Crossover Expansion Joint
- Rotor Shaft Seals
- Housing/Casing Joints
- Bolts
- Lines/Appurtenances (See Below)

Turbine/Condenser Transition (Neck of Condenser)

- Expansion Joint
- Manways/Doors
- Pipe Taps, Joints, Fittings, Valve Stems, and Instrumentation

Condenser

- Condenser Vacuum Breaker
- Casing Welds (Especially at old repairs)
- FW Heater Penetration, Thermal Sleeves, Pipe Taps/Penetrations
- Manways/Doors
- Connected Lines and Appurtenances (See Below)
- Slop Drains and Other Drain Lines That Happen to Pass Through Condenser

Connected Drain/Vent Lines

- Internally Thinned Due to Corrosion, Erosion, or Flow Accelerate Corrosion (e.g., DA Vents, Heater Vents, Heater Drains, Emergency Dump Lines, Steam Line Drains, Before/After Seat Drains
- Pipes Can Be Cracked At Welds (Turbine Bypass, Reheater Bypass, Emergency Heater Dumps, etc.).
- Also See Loose or Cracked Joints in Next Category

Connected Instrumentation, Fittings and Other Appurtenances

- Cracked or Loose Pipe/Tube Taps
- Loose, Corroded or Cracked Joints: Threaded (e.g., Loose or mismatched standards), Compression, Welded, Flanged, Gasketed
- Valve Stems
- Level Indicators
- Pressure Gauges
- Orifice Plates

Condensate Pump Suction

- Flanges
- Strainer
- Expansion Joint
- Pump Shaft/Seal
- Pump Housing (Including area in contact with floor, earth/etc.)

Other Condensate Tanks & Pumps

- Heater Drip/Drain tank
- Gland Steam Condenser Drain Tank
- Pump Seals

- Miscellaneous Drain Tanks or Sumps (which are pumped or are drawn into the condenser such as boiler feed pump seal leakoff tanks, air heater drain tanks, clean sumps)

Vacuum Pump Monitoring

Vacuum pump performance eventually will decline. Utility condensers usually have two or more vacuum pumps per condenser. Monitoring the relative performance of the vacuum pumps over time can indicate when one pump is in need of an overhaul or replacement. One reference reported that a declining vacuum pump will draw fewer amps (less current) than the better vacuum pump [13]. By changing which vacuum pump or which combination of vacuum pumps are in service, it is possible to determine which is the poorest performing pump. With both pumps in service, the following criteria indicate that a vacuum pump is in need of overhaul or replacement (as compared to one of the other vacuum pumps):

- Lower total pump suction flow rate on the marginal vacuum pump. (Note that a higher pump discharge flow rate on the other pump can be due to air inleakage on the vacuum pump seals. This is an advantage of the devices which measure the flow rate on the suction line).
- Lower Water to Air Ratio
- Lower current flow (amps) on the vacuum pump motor

By observing the changes when a vacuum pump is removed from service, it is possible to assess which vacuum pump is the worst performing pump. The following bullets list the criteria that indicate a vacuum pump is not performing as well.

- Lower vacuum (higher backpressure) when this vacuum pump is in service (when the better pump is removed from service)
- Higher turbine back pressure or condensate temperature when this vacuum pump is in service (when better pump is removed from service)

Another factor that can be easy to fix and can have a tremendous effect on vacuum pump performance and condenser back pressure is the vacuum pump seal water temperature. Vacuum pumps are sealed by the seal water. As the seal water temperature rises, the vacuum pump pressure necessarily increases to match the saturation pressure of the seal water (which essentially boils under the internal vacuum). The seal water usually has a cooler to lower its temperature.

As indicated in Figures 5 and 6 of Reference 15, cleaning a scaled seal water cooler dropped the seal water temperature from about 120-125°F to about 86-91°F and corresponded with reductions in turbine backpressure from 3.8-4.0 inch Hg to 2.6-3.1 inch Hg [15]. This is about a change of 0.9-1.2 inch Hg in backpressure for a change of 34°F. Close monitoring of the vacuum pump seal water temperature and trending with the turbine backpressure is recommended. Options for lowering this temperature could include cleaning coolers, increasing cooling water flow, or use of a cooler water (e.g., chilled water) supply.

TURBINE BACK PRESSURE

There are a number of factors which can increase turbine backpressure: increased air inleakage, increased heat duty on the condenser (due to increased turbine load, leaking turbine bypass, heater drain or dump lines, steam traps, steam line drains or other high energy streams being routed back to the condenser), reduced cooling water flow, obstructed or fouled tubes, and increased cooling water temperature. There can be an operating range within which increases in back pressure do not adversely affect heat rate (see Figure 9 of Reference 3).

For condensers with vacuum pumps, air inleakage typically needs to be above the levels in Figures 2 and 3 to significantly affect turbine backpressure [8].

HOTWELL/CONDENSATE PUMP DISCHARGE CATION CONDUCTIVITY

With proper control of air inleakage, condenser leaks, and makeup purity, cation conductivities of 0.2 µS/cm or less in the condensate pump discharge generally are readily achievable during normal operation. If someone is feeding carbohydrazide or other organic compounds, baseline cation conductivity can be higher.

Figure 2 presents an example of the effect of air inleakage and condenser leaks on cation conductivity and sodium in condensate. This is for a ~255 MW 1800 psig turbine with a water-cooled condenser and no condensate polishing. Initially, air inleakage was high and condensate cation conductivities also were high. Condensate sodium levels were satisfactory during this initial period. The air inleakage was fixed and the cation conductivities dropped to below 0.2 µS/cm. As indicated in Figure 2, two condenser leaks were subsequently experienced and both sodium and cation conductivities provided definitive indication of cooling water contamination. If air inleakage had not been fixed, the background cation conductivity would have obscured the condenser leak effect on condensate cation conductivity.

HOTWELL/CONDENSATE PUMP DISCHARGE DISSOLVED OXYGEN

The use of dissolved oxygen and cation conductivity for assessing air inleakage is most appropriate for units that are base loaded or that only cycle load. For two-shifting or peaking units (which go in and out of service), the system will have air everywhere to start unless the makeup is degasified and adequate air exclusion measures are applied during layup. Therefore, cation conductivity and dissolved oxygen will tend to be high in these facilities and chemistry readings can be much more difficult to interpret and control. Table 3 presents a decision matrix for interpreting the effect of air inleakage on condenser backpressure, condensate pump discharge cation conductivities and dissolved oxygen concentrations. The effect of condenser tube leaks is not considered.

WATER/STEAM LEAKS

When water or steam leaks out of a component, air can leak or diffuse into the component countercurrent to the outward flow of steam or water. Therefore, it is standard practice to continually work at finding and fixing steam and water leaks from the steam/water cycle. Something that is leaking during service may be a source of air intrusion or nitrogen leakage during layup. Therefore, a policy of zero tolerance for any leakage during service will aid in the control of air intrusion during layup (and the subsequent startup).

Components that are under vacuum during service will not necessarily have any visible water leakage during service since the water is maintained inside the components by the vacuum. Upon shutdown, areas that were under vacuum will contain some condensate and they may start to drip or bleed moisture. A tiny drip noted during the shutdown or out-of-service condition may correspond to a rather large air leak during prior and subsequent service. Therefore, it is important to inspect the unit closely upon shutdown for any signs of moisture in areas that were dry during service. This may be another opportunity to use thermography as moisture evaporating from wet areas will lower the metal surface temperatures.

Figure 2 – Air Inleakage and Condenser Tube Leakage Effect on Cation Conductivities

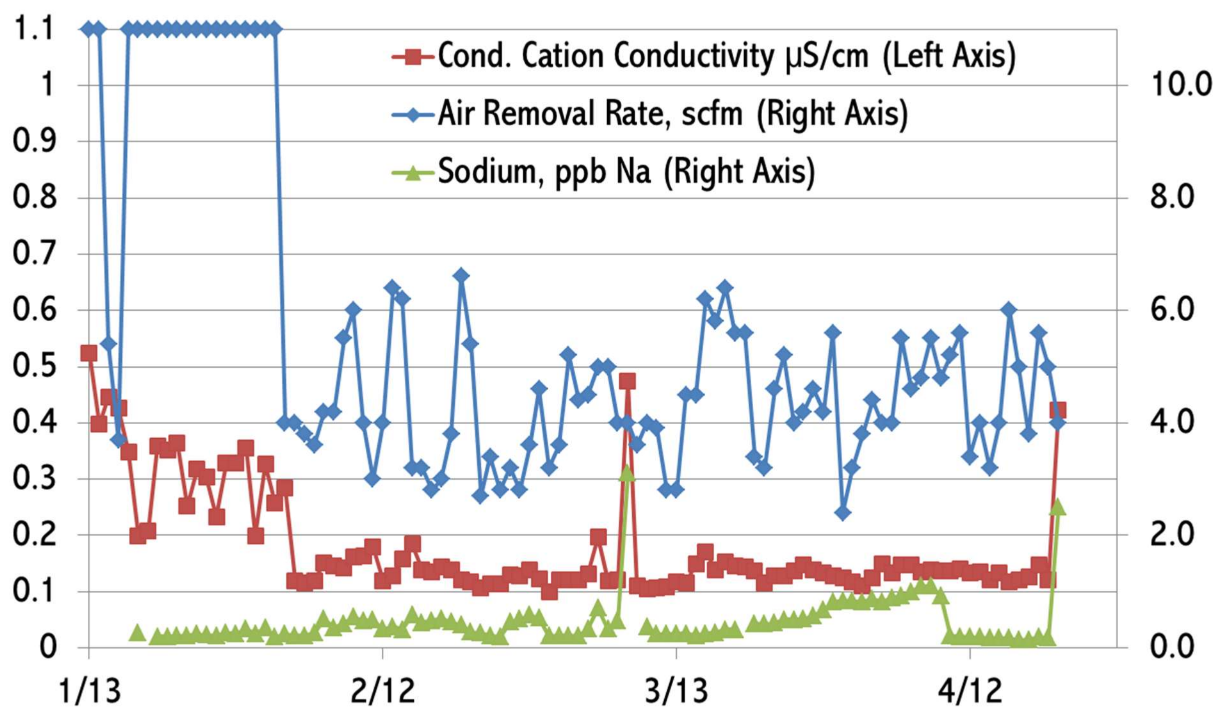


Table 3 – Dissolved Oxygen Cation Conductivity Changes for Select Air Inleakage Problems

Condition	Air Removal Rate	Condenser Back Pressure Due to High Air Inleakage	Hotwell/CPD Sample		
			Cation Conductivity	Dissolved Oxygen	
				Hotwell Not Subcooled	Hotwell Subcooled
Air Leaks Above Water Level	>2-3 scfm/100 MW (of Design Capacity)	Normal to High	High	Normal to High	High
	<1-3 scfm/100 MW (of Design Capacity)	Normal	Normal to Moderate	Normal	Normal to High
Air Inleakage Below Water Level	~0.01 scfm per Million pph of condensate flow (a)	Normal	Normal	~10 ppb Increase	~10 ppb Increase
Reduced Vacuum Pump Capacity	Normal to Moderate	Possibly High	Normal to Moderate	Moderate to High	High

(a) Or 0.60 mL/min per metric ton/hour of condensate flow. Based on 10 ppb increase in dissolved oxygen, 70°F air, 0.075 lb. air/ft^3, and mass fraction of oxygen in dry air of 0.231.

Surface moisture also can be due to external condensation if the metal is below the dew point, if another overhead component is leaking, or if the area may be wetted when it rains.

FINDING & FIXING (REDUCING) AIR LEAKS

It is advised to combine finding air leaks with fixing air leaks. Sealing air leaks can be fairly difficult and the only way to ensure that the repair is performed effectively is if the air test crew is on site and can retest the area after repairs. Also, as repairs are made, the total air inleakage decreases and the air test crew should retest areas already checked, as smaller leaks may have been masked by some of the larger leaks.

Justification

With the current fiscal condition of many power plants, it can be difficult to justify obtaining funding for equipment, personnel, or contractors to find and reduce air inleakage. In cases of severe air inleakage that actually affects turbine backpressure, the payback can be very quick. The following present several examples of the effect of turbine backpressure on heat rate.

- Oil/Gas Fired Boiler Supplying a 520 MW Turbine. Heat rate increases 116.5 BTU/kwh per in. Hg of turbine backpressure increase [6].
- Nuclear Unit Supplying a 810 MW Turbine. Above 2.5 inch Hg backpressure, the heat rate increases an average of 200 BTU/kwh per in. Hg increase of turbine backpressure [3].
- A 200 MW unit in India. A fouled condenser was cleaned and a 14 mm Hg reduction in backpressure corresponded with a 31 kcal/kwh improvement (reduction) in the heat rate, which corresponds to 223 BTU/kwh per inch Hg reduction in turbine backpressure [14]. Information on the fuel and unit design was not provided.

Using the lowest heat rate correlation presented herein and a current gas price ($2.48 USD/Million BTU) yields a cost of $108,180/month/inch of back pressure. This would be more than sufficient to justify funding air inleakage testing.

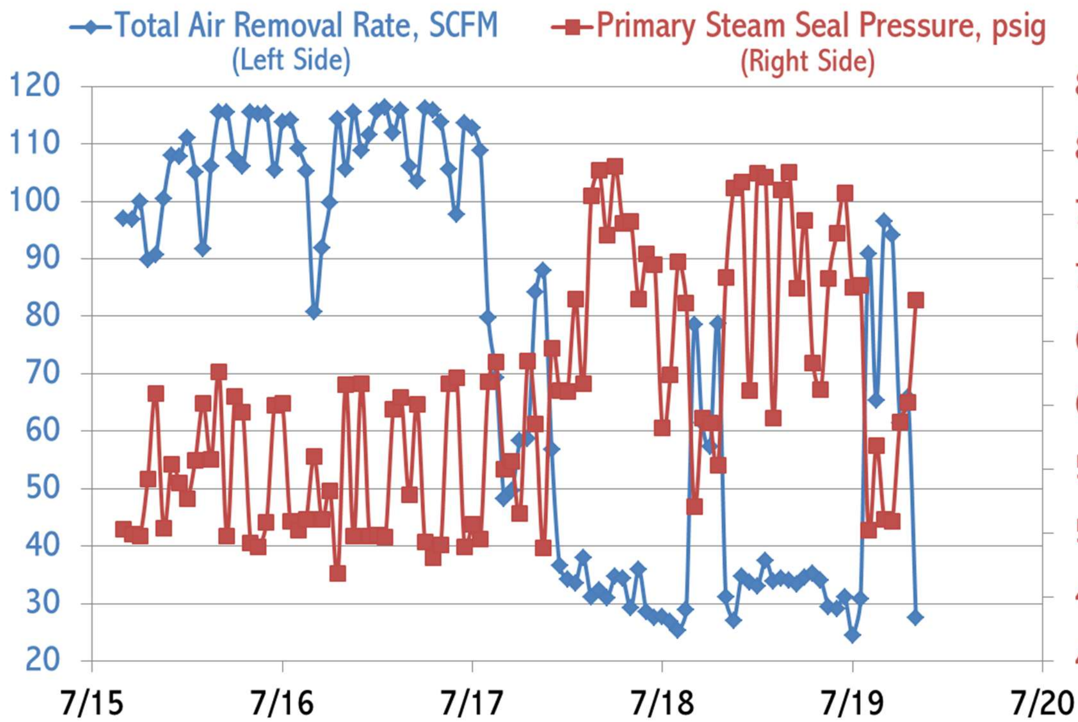
It should be possible to develop a unit specific correlation by checking the performance before and during air removal calibration checks with different levels of air inleakage and condenser backpressure. If data do not indicate an increase in heat rate, it becomes more difficult to cost justify finding and reducing air inleakage.

With the proper assumptions, it may be possible to demonstrate that a reduction in air inleakage reduces corrosion product transport and chemical cleaning frequency. Also, avoidance of turbine rotor cracking could be used to justify finding and fixing leaks if the air inleakage is well above suggested levels. Reference 3 presented a correlation between air inleakage and turbine rotor cracking [3].

USING STEAM SEAL PRESSURE TO REDUCE AIR INLEAKAGE

Air inleakage around the turbine rotor is prevented through the use of steam seals. Often leakage in this area requires an outage for repair. A temporary means of reducing this type of air inleakage is to increase the steam seal pressure to the upper end of its allowable operating range. An example for the correlation between steam seal pressure and air removal rate is presented in Figure 3. Each point is an hourly reading from the PI data management system. It was a ~670 MW maximum capacity turbine with a split condenser (two shells), and two Intech Rheovac air inleakage monitors (one per condenser). The total (sum of both sides) air inleakage is reported.

Figure 3 – Air Removal Rate and Steam Seal Pressure Versus Time



This unit had known air inleakage problems including leakage on the rupture disks and turbine rotor. It was going to require an outage to effect repairs. During July 18-19, when the steam seal pressure increased, air removal rate decreased and when the steam seal pressure was reduced, air removal rates increased.

The transition on the 17th looks as if the air inleakage was decreasing before the seal pressure increased. However, this was due to changes in turbine load. Figure 4 shows the air inleakage/removal rates and load versus time. As indicated in the figure, at the initially excessive air inleakage rates, the air inleakage was reducing whenever load was reducing and increasing whenever load was increasing. On the 17th, the air inleakage was once again increasing with load when the pattern was abruptly stopped apparently by increasing the steam seal pressure.

Figure 5 shows the apparent dependence of the air inleakage rate on the steam seal pressure. There is some scatter (load based) at the lower steam seal pressures, but once the pressure was increased to 6.8-8.0 psig for this turbine, the air inleakage rate remained much lower. These air inleakage rates were still quite high by industry standards, but it demonstrates the positive effect that can be realized by a simple operational change.

Cation conductivity also can be improved (reduced) from increases in steam seal pressure. Figure 6 presents a graph of the cation conductivity versus steam seal pressure for this period of time. There is a clear correlation that when the seal pressure was increased, the air inleakage and cation conductivity decreased. Many plant chemists would be surprised to see that the cation conductivities were not higher considering the truly excessive air inleakage rates in this example.

Figure 4 – Turbine Load and Air Removal Rate Versus Time

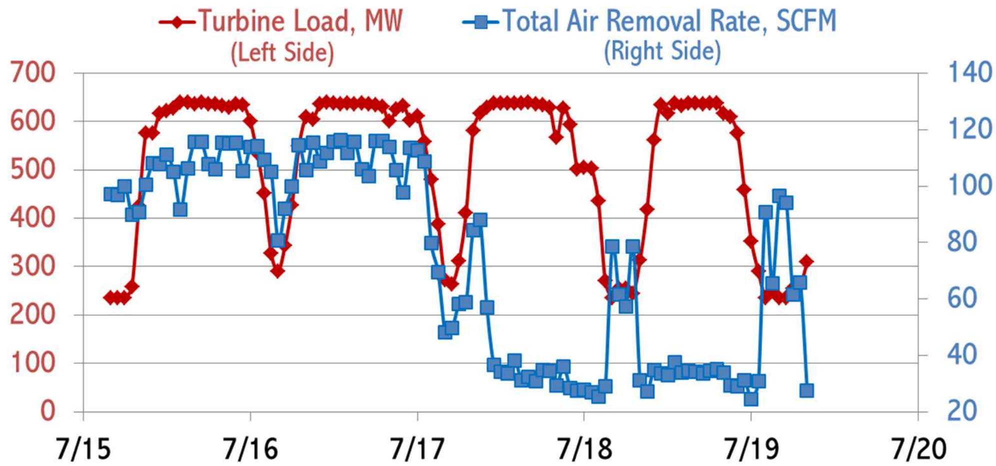


Figure 5 - Total Air Removal Rate Versus. Steam Seal Pressure

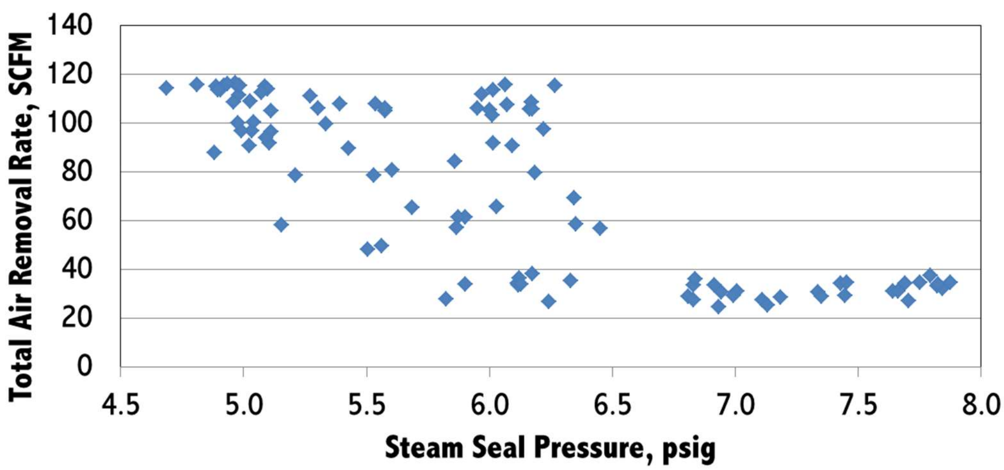


Figure 6 – Hotwell Cation Conductivity Versus Steam Seal Pressure

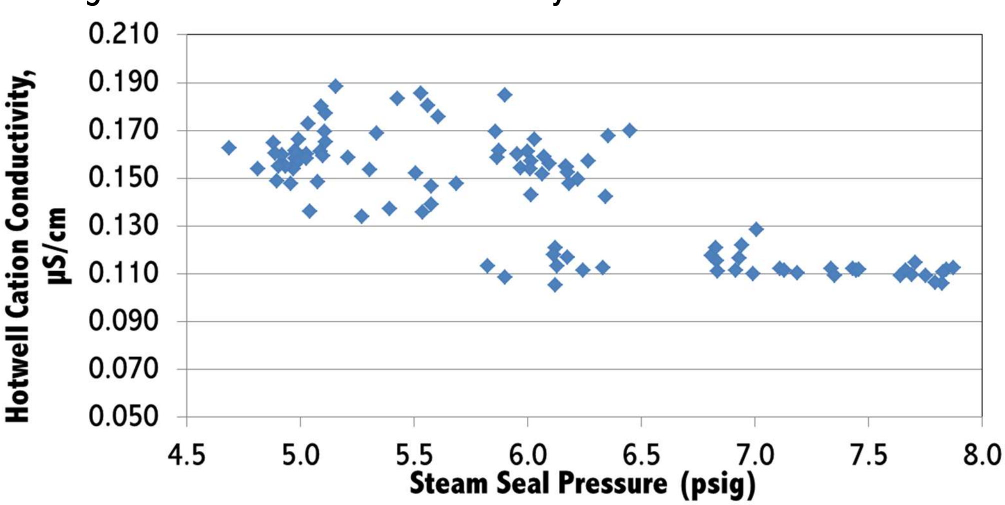
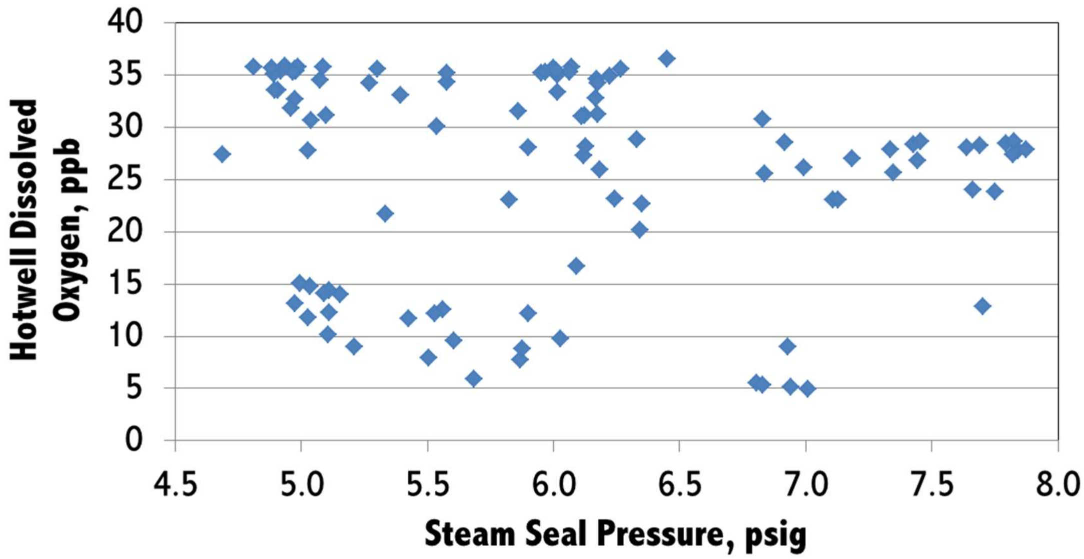


Figure 7 – Hotwell Dissolved Oxygen Versus Steam Seal Pressure



One key factor is that the unit operates with full flow deep bed condensate polishing (in the hydrogen cycle). Therefore, all of the carbon dioxide is removed from the condensate. For plants without polishers, this carbon dioxide would accumulate in the cycle until the losses due to venting and air removal balance the air inleakage rate and so much higher cation conductivities would be expected. Every condenser seems to handle air inleakage differently. See Reference 16 for a better understanding of how air storage in the condenser design affects a condenser's tolerance for air inleakage [16]. Note that the "Hotwell" samples are withdrawn from the discharge of the condensate pump at this facility.

In this example, the condensate pump discharge dissolved oxygen levels also were high. This was not surprising considering the excessive air inleakage rates. However, as indicated above, in Figure 7, the dissolved oxygen only experienced a slight improvement (reduction) with the initial reduction in air inleakage. This finding suggested that some of the elevated dissolved oxygen may be related to an air leak below the water line or some other factor (e.g., air bound regions of the condenser due to the still unusually high air inleakage rate and/or subcooling of the condensate). The makeup is degasified (probably achieves about <100 ppb of dissolved oxygen) and so elevated dissolved oxygen levels probably were not related to the makeup water.

TURBINE ROTOR AIR INLEAKAGE NOT RESPONDING TO INCREASED STEAM SEAL PRESSURE

Air inleakage testing of one unit indicated a problem with one of the turbine seals, but it did not seem to improve (reduce) with increases in steam seal header pressure. Also, initial visual inspections by the turbine crew during the turbine outage did not locate any mechanical problems with the turbine seals. The problem was eventually traced to the steam seal supply line to the steam seal in the neck of the condenser. As shown in Figure 8, this ~4-inch diameter line looked fine from above. However, as shown in Figure 9, viewing the line from below, we found a large (1.0-1.5-inch wide by 3-inch long) opening in the bend as it started to go up and into the steam seal.

Figure 8 – Top View of Steam Supply Line in Condenser

Figure 9 – Hole in Steam Supply Line in Condenser

It is expected that while the steam seal supply header had pressure, all or most of the steam for this seal was drawn out through the hole by the condenser vacuum. Therefore, the local steam seal was actually under vacuum rather than pressurized.

Usually, we expect lines to thin out from the top and from the outside in a condenser. However, it appeared that this line had thinned out from the inside. A failure analysis was not performed, but it looked like it was mainly due internal erosion and/or two-phase flow accelerated corrosion. This line had never been replaced and the unit was almost fifty years old. Steam flowing through the long, horizontal uninsulated steam seal supply lines in the neck of the condenser probably cooled and may have experienced some condensation before reaching the steam seal. This could lead to two phase erosion or corrosion. Once the hole formed, the steam velocity leaking out to the condenser vacuum would have increased and contributed to erosion and expansion of the hole.

While no photographs were provided, others have reported similar steam seal supply system damage (13). In the cited case, accidentally tripping the steam packing exhauster surprisingly reduced the hotwell dissolved oxygen level! (13).

AIR INLEAKAGE VIA PERFORATED TURBINE SLOP DRAINS

Quite a few condensers have carbon steel turbine slop drains with horizontal sections in the neck of the condenser. These horizontal sections are prone to rapid, external, two-phase flow accelerated corrosion. Figure 10 presents a view of one of these 1-inch diameter lines that had been perforated.

Figure 10 – Perforated Turbine Slop Drain

This is by no means an unusual occurrence. We have been in quite a few condensers with leaking slop drains. When the lines are perforated, they become a source of air inleakage to the condenser. Inspection of these lines should be a standard part of routine condenser inspections.

CONTROLLING DISSOLVED OXYGEN

Some of the main causes of high dissolved oxygen concentrations in the condensate are provided in the following list.

- False high readings
- Air inleakage below the water line (See Table 3)
- Air inleakage above the water line (See Tables 2-3)
- Oxygenated Makeup
- Cycling Service

Table 4 presents a summary of some suggested nonchemical (no oxygen scavenger addition) dissolved oxygen control measures. Its focus is on prevention of air intrusion and thermal and mechanical means of removing or excluding dissolved oxygen and other noncondensable gases.

Table 4 – Nonchemical Dissolved Oxygen Control Measures

Reasons for High Dissolved Oxygen	Controls
All Samples	
False High Reading	Put throttling valve for slight backpressure on sample system outlet. Seal/avoid threaded fittings in sampling system and dissolved oxygen analyzer. Use glass rotameters. Replace or add extra isolation valve on common demineralized water flush supply for the analyzers
Condensate Pump Discharge (CPD)	
Air Inleakage Directly Into Water	Find and fix leaks in flooded areas in Table 2.
Inadequate Cooling in Air Removal Zone	Clean tubes in air removal zone. Sometimes these tubes foul faster because the tube material is less biostatic (e.g., stainless steel).
Low Vacuum Pump Flow (Low Water Vapor to Air Mass Ratio)	Put additional vacuum pump in service and schedule maintenance/replacement of vacuum pumps.
Condenser Subcooling	Drop to one cooling water circulation pump. Recycle warm water from condenser outlet to circulation pump inlet.
Condenser Design	Redesign condenser
Cyclic Service	Exclude air (nitrogen pad heater shells, condenser, boiler, and reheater) during layup. Degasify Makeup
Oxygenated Makeup	Degasify makeup: Membrane degasification, install spray header in condenser, install nitrogen sparger in demineralized water storage tank.
Feedwater	
Poor Deaerator Performance	Adjust vent rate to optimum level. In next outage, inspect and repair problems in deaerator (broken steam baffle, tray box door or walls, deformed, loose or leaking nozzles, and upset trays)
Leaking Deaerator Storage Tank Manway	Temporarily seal up leak and check sealing surfaces in next outage

Reasons for High Dissolved Oxygen	Controls
Boiler Feed Pump Seal Leak	Check pressure drop across suction strainer and clean if high. Fix pump seals in next overhaul
High Condensate Dissolved Oxygen	See CPD dissolved oxygen controls

EFFECT OF INSTALLING NEW MAKEUP SPRAY HEADER

A facility had a demineralized makeup system that normally flowed directly to the condenser and excess condensate spilled over into the condensate/demineralized water storage tank. The original condenser had very poor distribution of the demineralized water: it consisted of a few feet long section of a pipe with a few large openings. Station operations and chemistry personnel noted that the condensate pump discharge oxygen levels were largely a function of the makeup rate. When the makeup rate increased, the condensate dissolved oxygen concentrations increased and baseline levels were high. In order to improve oxygen removal from the makeup in the condenser, we assisted the plant in the design of a spray header which was subsequently installed by station personnel. As indicated if Figure 11, this was merely achieved by extending the existing makeup line to a drilled pipe distributor above the condenser tubes. Since the condenser had stainless steel tubes, concerns of tube erosion due to the water spray were minimal. A different distribution system layout has been planned for a condenser with copper alloy tubes.

Figure 12 presents several graphs of the condensate pump discharge dissolved oxygen levels in the condensate. The dissolved oxygen was monitored continuously with a Swan dissolved oxygen analyzer and a set of readings were reported daily along with other station chemistry data. The top (blue) line in the figure shows daily readings in 2004 (prior to the retrofit). The green line (2006) shows the condensate dissolved oxygen levels after the retrofit and the red line shows the dissolved oxygen levels after some air leaks were fixed. While these dissolved oxygen levels still were a little elevated, this unit is operated on AVT(O) and the condensate/feedwater system is all-steel. Therefore, the slightly higher dissolved oxygen levels were not considered to be a problem. Cation conductivities (not shown) are consistently less than 0.20 µS/cm and the unit does not use a condensate polisher.

It is speculated that some of the problems with dissolved oxygen control at this facility is partially related to subcooling in the condenser. A review of more recent data in 2010 and 2011 (not shown) indicate that the lowest dissolved oxygen levels are experienced in the summer when the average cooling water temperatures are ~79°F and the highest dissolved oxygen levels are in the winter when the water temperatures are <35°F. Only one circulator is operated in cold weather. However, this operating mode is not necessarily sufficient to prevent subcooling. We unfortunately do not have the air inleakage readings for the period in which these data were present.

MEMBRANE DEGASIFICATION OF MAKEUP

A HRSG facility that operated intermittently installed a nitrogen blanketing system for the HRSG units and a degasification membrane on the makeup to the cycle. The effluent of the degasification membrane is usually <5-10 ppb O_2 and it goes through an existing distributor (with fairly large holes) in the condenser. The membrane system resulted in dramatically better control of condensate pump discharge dissolved oxygen concentrations.

Figure 11 – Sketch of Makeup Spray Header for Condenser

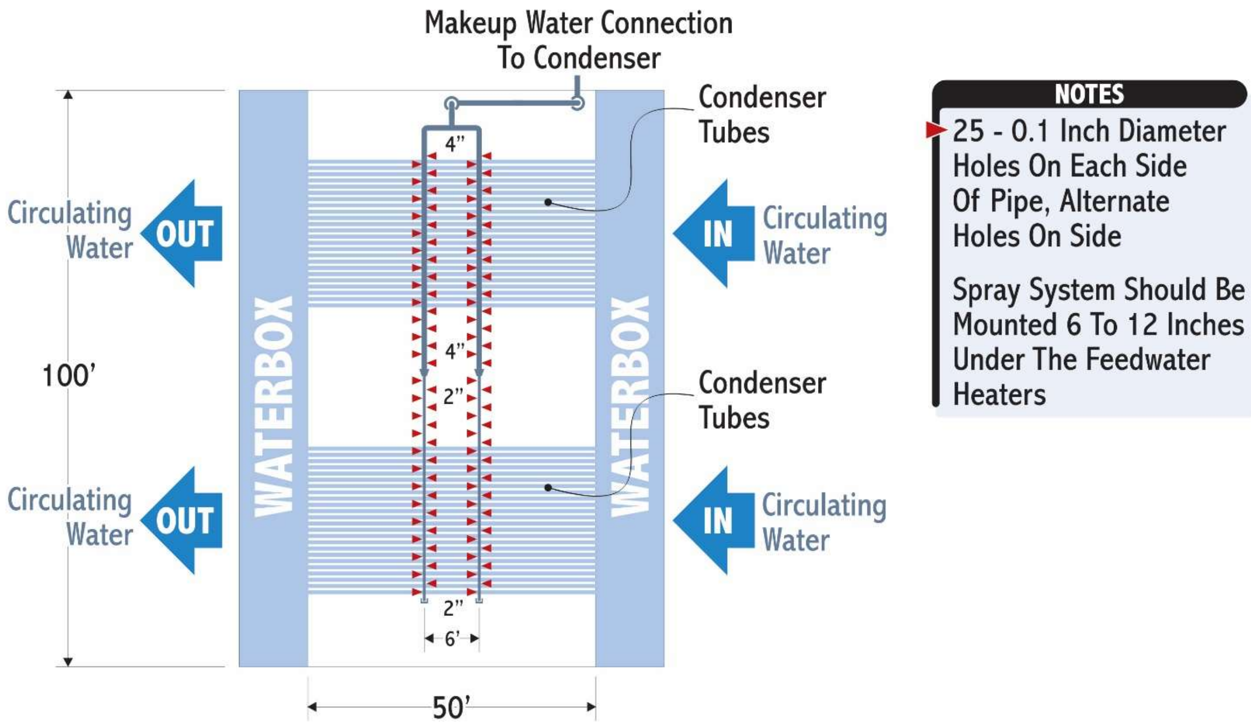
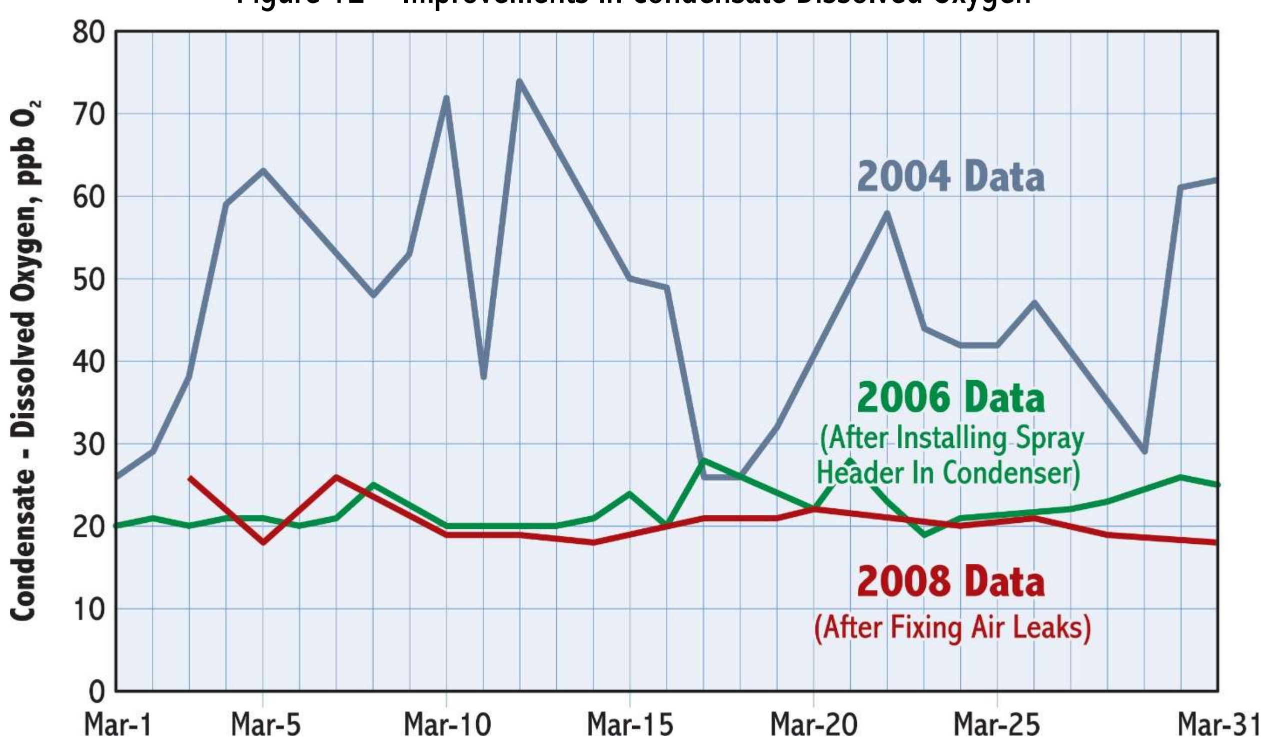


Figure 12 – Improvements in Condensate Dissolved Oxygen



The units now are essentially base loaded. When they switched to base loaded service, the condensate pump discharge dissolved oxygen levels often were below 1 ppb as O_2. Because of the system design, when they bypass the degasification membrane for membrane cleaning, the makeup goes into the hotwell just above the water level and condensate pump discharge dissolved oxygen levels can increase to 30-100 ppb as O_2 or more. They currently have a project planned to install a regulated bypass around the degasification membrane to the normal makeup distributor so that they can set the dissolved oxygen blend in the makeup to achieve a target level of dissolved oxygen in the condensate and feedwater. The unit is an all steel cycle and it is expected that controlling rather than minimizing condensate pump discharge dissolved oxygen levels in this manner will reduce iron oxide transport to the unit.

A FEW TIPS ON STARTUP/SHUTDOWN AND CYCLING

This paper is rather long already and so a proper discussion of startup, shutdown, layup and cycling service is not practical. The following just provide a list of some of the principles which should be applied.

- Minimize prestartup recirculation time before establishment of a condenser vacuum and steam pad on the deaerator.
- Retain heat in the unit to keep systems pressurized with steam during overnight cycles.
- Maintain steam seals with auxiliary boiler or steam from another unit during overnight cycles.
- Rather than opening vents to atmosphere, apply nitrogen for nonmaintenance shutdowns to components which would otherwise be vented or draw in air when removed from service.
- Install degasification system on demineralized makeup supply to unit with a means of providing this degasified water to the unit (e.g., downstream of condensate pump discharge) as top-off water.
- For systems using oxygen scavengers, a higher dose of oxygen scavenger should be applied during startups and short layup periods.

SUMMARY

The paper provided an overview of air inleakage and dissolved oxygen monitoring and control and highlighted a few areas of interest. For those that flip to the summary, we have presented just the items most likely to be new or of interest to one or more attendees.

- The new performance test code for condensers (PTC-12.2-2010) has higher limits for air removal rates, which roughly correspond to ~2-3 scfm/100MW, which is ~2-3 times the former industry limit.
- Direct injection of just 0.01 scfm of air per million pph of condensate flow (0.6 mL/min per metric ton per hour) will result in a 10 ppb O_2 increase in condensate dissolved oxygen.
- Inspect steam/water cycle for water drips or wetness during shutdown. Tiny amounts of water seepage during shutdown (from components normally under a vacuum) indicate points of air leakage during service.
- Use the Unit heat rate to cost justify finding and fixing air leaks.
- Increased steam seal pressure can result in dramatic reductions in air inleakage and condensate cation conductivity.
- Closely inspect steam seal supply lines for leaks during outages.
- Check for perforated slop drains during condenser inspections.

- A fairly simple modification of the demineralized water line in the condenser can significantly reduce the effect of makeup dissolved oxygen on condensate dissolved oxygen.
- Membrane degasifiers provide excellent removal of dissolved oxygen. This actually can lead to condensate dissolved oxygen levels that are too low in some systems. Therefore, it is suggested to install a bypass line (with double valves) in the event that a mix is required for optimal dissolved oxygen levels.

REFERENCES

1. Gary R. Elder, "Leak Testing, A Quality Assurance NDT Method", ASTM Standardization News, January, 1995, pp. 46-49.
2. S. Ian Garbutt, Robin Walker, Quantitative Air Ingress Leak Detection in Power Plant Turbine Condensers, Powerplant Chemistry, 4 (8), 2002, pp. 475-481.
3. F.X. Baldino, J.C. Bellows, J.E. Richards, W.M Jackson, Air Inleakage Control in Power Plants, Volume 45, Proceedings of the American Power Conference, 1983, pp. 184-188.
4. Condenser Air Inleakage Guideline, TR-112819, EPRI, January 2000 (Public Domain).
5. Hunt Down Sources of Condenser Air In-Leakage, Power, May/June, 1997, p. 16.
6. Joseph W. Harpster, Reducing Dissolved Oxygen Under Conditions of High Air Ingress, Powerplant Chemistry, 4(9), 2002, p. 535-541.
7. Fred Maner, JEA Trims Condenser Air In-leakage and Realizes Significant Savings, Power Engineering, November 2001, pp. 115-118.
8. Steam Surface Condensers, PTC12.2-2010, The American Society of Mechanical Engineers, New York, NY, 2010, Based on Table 3.4.1, p. 6.
9. Standards for Steam Surface Condensers, Tenth Edition, Heat Exchange Institute, Inc., Cleveland, Ohio, September 2006.
10. Power Engineering Magazine, April, 2006.
11. Condenser Performance Monitoring Practices, 1007309, EPRI, September, 2002 (Public Domain).
12. Flow Measurement, PTC-19.5-2004, ASME, New York, NY, 2005.
13. Dave Leissner and Richard Putnam, "Hitting a Home Run!! --- A Condenser Success Story, www.trican.ca/pdf/services_technology/cleaning_case2.pdf.
14. G.E. Saxon, Jr. and R.E. Putnam, "Improved Plant Performance Through State-of-the-Art Condenser Cleaning and Air Inleakage Detection", IJPGC-2003-40179, Proceedings of the International Joint Power Generation Conference, June 16-19, 2003, American Society of Mechanical Engineers.
15. Kevin Boudreaux, Improve Condenser Performance Through Better Instrumentation, Power Magazine, June 2012, pp. 74-78.
16. Tim Harpster, Air Storage: The True Root Cause of Condensate Dissolved Gases and Poor Condenser Performance, Tenth International Conference on Cycle Chemistry in Fossil and Combined Cycle Plants with Heat Recovery Steam Generators, EPRI, Seattle, WA, June 26-28, 2012.