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Optimize water-treatment economics at your powerplant

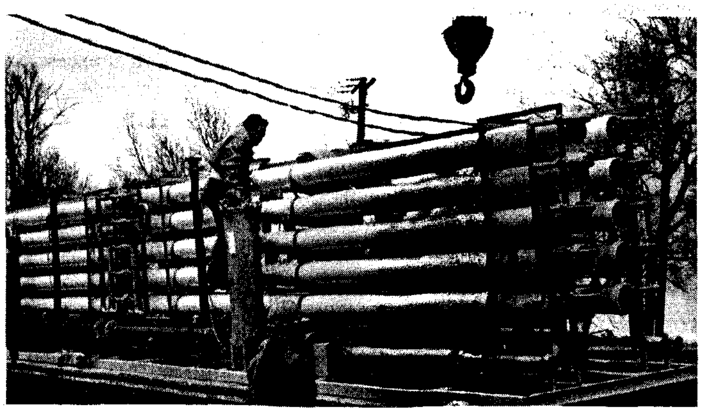
O&M costs related to cycle chemistry/corrosion account for at least 10% of the cost of electricity. Power producers can minimize overall long-term cost by improving system chemistry

By Sheldon D Strauss, Senior Editor

Power producers are well aware of the economic penalties they incur when a component failure causes a plant shutdown. One of the heaviest financial burdens is attributed to steam-cycle corrosion, which is said to account for about half of the forced outages experienced in the US electric-utility sector and about $3-billion annually in operating and maintenance costs.[1] Attractive financial returns are possible by improving cycle chemistry, because of the high benefit-to-cost ratios obtainable—in some cases as high as 1000:1. Upgrading chemistry monitoring with a continuous sodium analyzer at a cost of a few thousand dollars is a classic example. Keeping track of a steady increase in that feedwater contaminant, with its potential for turbine and superheater caustic corrosion if unchecked, can eliminate millions of dollars in maintenance costs.

Escalating competition and staff downsizing have increased the pressure on water chemists to optimize performance while minimizing operating and maintenance (O&M) costs. At the same time, modifications made in the interest of economy cannot compromise overall system reliability—for example, it would be unwise to shut down a troublesome lime softener to reduce maintenance cost without providing an alternative to reduce water hardness and ionic loading on the system demineralizer. Result could be serious boiler or afterboiler deposits, or at least the need for larger resin beds, offsetting the expected savings.

Water chemists have always concentrated on minimizing costs. For small, low-pressure boilers, steps they have taken include careful control of chemical residuals, elution studies to minimize regenerant use for demineralizers, replacement of coagulants with polymers, and blowdown minimization. In high-pressure systems, feedwater consists almost entirely of condensate returns, and cutting O&M costs by reducing chemical consumption, minimizing regenerant waste, and the like are standard practice. Nevertheless, a critical ongoing review of system chemistry can usually reveal additional opportunities.



1. **Cycle-chemistry improvement with rapid payback is typified by RO retrofit for makeup pretreatment at Midwest Power Systems' Neal station**

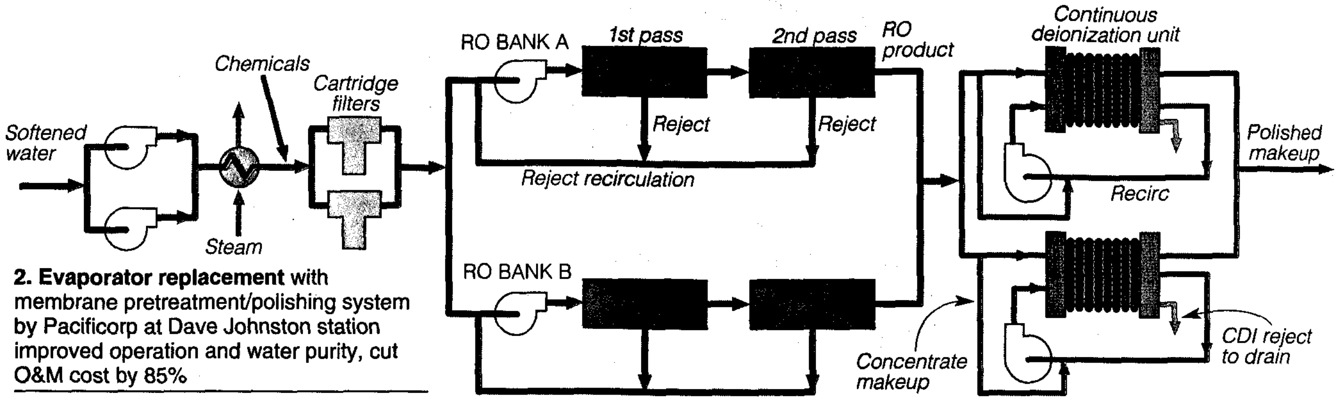
On the other hand, there are times when changes that increase O&M costs may be dictated. The care of charcoal beds used to control organics is a good example. Periodic sterilization may be needed to prevent bacteria buildup in the charcoal adsorber. It adds to O&M cost, but, because it protects downstream resin beds from fouling, even more expensive subsequent maintenance can be avoided.

Another excellent example was provided very recently by ComEd (formerly Commonwealth Edison Co), which had several operating units that were suffering severely from boiler-tube failures related to corrosion fatigue. Evidence pointed to boiler-water DO (dissolved O_2) as accelerating the corrosion-fatigue mechanism. Recent laboratory studies supported this conclusion.

As a remedy, the utility revised its start-up procedure by introducing in-situ boiler-water de-oxygenation. Startup hold points were enforced, preventing light-off of a forced-circulation boiler until DO had been reduced to less than 200 ppb. "Initial results of the change were phenomenal," according to system chemist Arne Lindberg. For some units, boiler-tube leaks decreased by over 50%. As Lindberg points out, chemical costs associated with startups have risen several hundred dollars, but tens of thousands of dollars have been saved by avoiding tube leaks.

Note that the presence of feedwater DO is not always undesirable. In Europe, operators of supercritical once-through boilers, for example, have turned to oxygenated feedwater treatment—or OT—to improve system availability by reducing corrosion-product transport to boilers. Basis of the improvement is prevention of ripple magnetite deposits, and resulting reduction of boiler pressure drop, total deposits, and tube surface temperatures in the radiant boiler section.

OT involves addition of DO (50-250 ppb), as opposed to its removal in conventional systems. At the same time, it requires feedwater of extremely high purity (cation conductivity below 0.2 μS/cm). Plants operating under these conditions



2. Evaporator replacement with membrane pretreatment/polishing system by Pacificorp at Dave Johnston station improved operation and water purity, cut O&M cost by 85%

have achieved at least 90% reduction of iron transport caused by pre-boiler corrosion. Reduced deposit buildup also minimizes associated tube-metal corrosion damage and the frequency of boiler chemical cleaning. Another effect is less regeneration of resin in condensate polishers, with consequent reduction in regenerant waste—the kinds of benefit achieved in demineralizer operation at an increasing number of powerplants. Additional economy results from the ability to operate resin in the H-OH form.

Under EPRI guidelines, utilities like Georgia Power Co and Ohio Edison Co have led the way in demonstrating the benefits of OT water chemistry. TU Electric, with perhaps the most extensive OT program, is converting 15 units of various boiler and cycle designs.

Another example of the resulting economic impact is Arizona Public Service Co's experience at Four Corners station, site of one of the most recent conversions. Total cost of the modifications required to convert Units 4 and 5 to OT chemistry was about $35,000. Reduction of chemical feed, outage time, and chemical cleaning — together with quicker startups—are expected to bring annual savings of $322,000. The utility projects another $800,000 saving from improved heat transfer through cleaner tube surfaces and subsequent efficiency gains. The total annual saving could be well over $1-million.

Even without a change in the prevailing chemistry-control philosophy, power producers report myriad examples and opportunities for optimizing water-treatment costs. However, careful analysis of both resources and applications is essential before making a commitment.

A typical example is the decision to collect and recycle boiler blowdown to conserve energy, water, and money. But, extensive modification of retention basins, piping, etc may be necessary. As another example, treated municipal wastewater offers cooling-tower makeup at a low price. That option was exercised at Palo Verde nuclear station, but it required considerable investment in trickling filters to reduce the ammonia and organic content of treated sewage (POWER Special Report "Water Management for Reuse/Recycle Special Report," POWER, May 1991, p 13).

Availability of capital is the key to major decisions regarding system changes, and may make the difference between action and inaction, or equipment lease vs purchase—possibly the purchase of high-purity water from a vendor with trailer-mounted equipment adjacent to or on the plant site.

A decision regarding capital investment, however, is a sophisticated process involving many considerations. As Frances Cutler, Southern California Edison Co, points out, the situation is even more complicated in a changing regulatory environment. Traditionally, rates charged by regulated utilities have been based on a combination of return on investment, prudent O&M budgets, and fuel costs. In the past, utilities could expect to recover the cost of capital improvements that reduced O&M budgets and/or fuel costs, even when the economic justification is based on a 20- or 30-yr lifetime.

There is no such security today, says Cutler. Consequently, from both a tax and a stranded-investment viewpoint, capital projects with a long payback period would be at a disadvantage because the investment would not be recovered until the equipment was fully depreciated. As a result, many utilities use five to 10 years as the payback criterion rather than the 20 years used in the past. Because shorter payback periods require large annual savings, capital projects may not be as attractive as before. And, of course, as competition unfolds, all investments are subject to change.

In the case of Georgia Power Co's Plant Bowen, more modest savings and a longer payback period were involved in the retrofit of a pre-demineralizer reverse osmosis (RO) system.[2] What made the change feasible, primarily, was the reduction of wastewater dissolved solids (a regulatory requirement) as an alternative to a back-end regenerant-waste neutralizer. Eliminating the raw-water clarifier and pressure filter included in the original treatment system contributed to the O&M cost reductions. Of course, the potential benefits in other cases can be large and rapid enough to override problems in capitalization.

RO and other membrane techniques, in fact, seem to be the focus of most of the utility activity in recent years designed to improve feedwater chemistry by enhancing the efficiency and reliability of makeup demineralizers and reducing the cost of their operation (see following case study). More and more plants are taking a close look at and installing upstream membrane systems to remove bulk quantities of dissolved solids from makeup, as a means of extending the length of IX-demineralizer runs (Fig 1).

RO and electrodialysis—more accurately electrodialysis reversal (EDR)—are the most common membrane techniques used, but newer methods are making their presence felt. These include continuous deionization (CDI) and eletrodeionization (EDI), two versions of an approach that combines elements of IX and EDR and eliminates the need for the regeneration performed periodically in IX systems.

The method incorporates mixed IX resin in the compartments formed by alternate cation- and anion-permeable membrane pairs of the familiar EDR stack. Impurity ions move toward opposite electrodes under the applied electric field, and a current excess created in the diluting compartments (alternate cells) dissociates water molecules into H+ and OH– ions at the electrodes. Moving rapidly in opposite directions, they displace trace impurity ions remaining on the resin beads. Effect is to regenerate the resin, while continuously producing high-purity water (POWER Special Report, "Water Treatment" May 1993, p 62).

Utilities are quite innovative in introducing new membrane-system designs. This is typified by Pacificorp's decision to replace a high-maintenance evaporator in the makeup system at Dave Johnston station. A combination RO/CDI retrofit was selected over a variety of options because of its high water recovery, low energy consumption, generation of no hazardous waste, and competitive cost.

The system selected features RO pretreatment (two stages) and CDI for final polishing, fully redundant to allow for maintenance without interrupting plant operation (Fig 2). After one year of operation, success of the retrofit is borne out by problem-free, low-maintenance operation and production of 32-million gal of high-purity water—despite severe variation in raw-water quality and temperature. The bottom line: Operating cost was reduced to $1.50 to $1.75/1000 gal from $11 with the old system.

Other membrane approaches winning acceptance for system retrofits are microfiltration and nanofiltration, both used to reduce fouling of demineralizer resin by finer suspended solids and colloids penetrating standard upstream clarification/filtration systems. RO itself provides a variety of options, both in membrane types and staging designs. Particular plant conditions, water analysis, etc dictate the best combinations—cellulose acetate vs polyamid construction, single stage vs multiple, single-pass vs double-pass, etc—for greatest cost effectiveness.

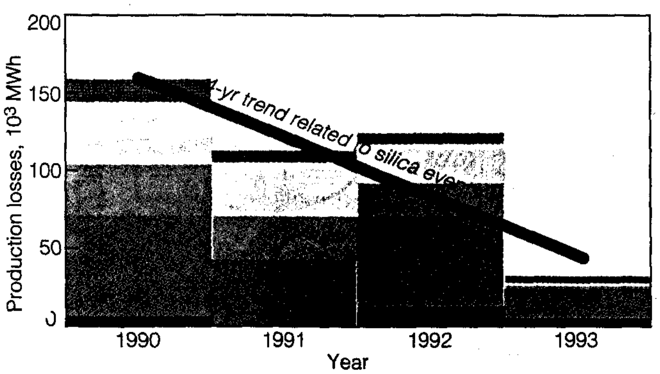
The utility industry's organized approach to water/steam-chemistry improvement began with the interim consensus guidelines promulgated by EPRI in 1986.[3] The effort entered a demonstration phase in February 1991 with inception of the Cycle Chemistry Improvement Program (CCIP), which focused strongly on reducing O&M costs. Under the guidance of EPRI and GPS Technologies Inc, San Diego, Calif, 12 participating utilities undertook comprehensive reviews of cycle chemistry and operating/maintenance experience at their plants to identify areas for improvement.

Action taken under the program began with the formation of permanent corporate and plant teams charged with correction of chemistry-related problems, followed by implementation of a computerized company-wide chemistry-event monitoring and reporting system, and training of plant personnel in the essentials of problem prevention and correction. Some of the program's specific goals aimed to:

- Eliminate chemistry-related turbine failures—blade/disk failures and generation losses resulting from deposition, for example.
- Reduce all chemistry-related availability losses to 0.1% or less.
- Eliminate need for chemical cleaning of once-through boilers, and extend intervals for drum boilers by 50%.
- Shorten startup times up to 80% by optimizing chemistry, impurity limits, and shutdown, layup, and startup procedures.

In the first three years, application of state-of-the-art cycle chemistry, monitoring techniques, and process control are credited with substantial reductions in availability and performance losses while reducing water-treatment costs.

O&M cost savings are exemplified by Pennsylvania Power & Light Co. A concerted cycle-chemistry review, led by the utility's senior project manager B H Herre, unearthed room for improvement in many areas. Among the more significant shortcomings identified early-on were the need for realistic chemistry limits (silica, for example) directly related to operating cost, and for greater understanding of operating essentials and chemistry costs among chemists/technicians (largely explained by the absence of a chemistry department at each plant).



3. Optimizing silica limits during startup reduced generation losses by 90,000 MWh for Public Service Co of Colorado. Tints are keyed to individual units

Identifying losses and making investments to attack the root causes of problems have led to cost reductions that "have paid for the program many times over," notes Herre. Although the final long-term audit is not yet complete, results provided by Herre (see table) indicate the effectiveness of CCIP-generated improvements in reducing chemistry-related costs in several major categories in a little more than two years of participation in the program.

Other CCIP participants also report successful progress toward the program's goals. Specific achievements include the following:

- Ohio Edison Co estimates it will save more than $9-million over a 10-yr period through reductions in boiler chemical cleanings, increased plant availability, and lengthened condensate-polisher runs attributable to OT conversions and other cycle-chemistry modifications at five once-through units.
- Gerald Gentleman station, Nebraska Public Power District, expects $700,000 annual savings from (1) improved chemical cleanings (totally eliminating boiler-tube failures), (2) installation of sodium and phosphate monitors ($56,000 cost), and (3) addition of a second condensate polisher, enabling both units to run full-flow, full-time. An interesting point is that, combined with an RO/zeolite-softener retrofit, the total cost of regenerant chemicals for the two units has been only $17,000 since the modifications were made, compared with $17,000 per month before.
- Moss Landing, Pacific Gas & Electric Co, estimates a saving of $2.4-million over 12 years through installation of main-steam sodium analyzers and extension of l-p turbine inspection intervals by two to four years. The utility also expects to save $2.5-million in avoided costs for l-p blading repair/replacement.
- Colorado Public Service Co reports a 90,000-hr reduction of availability losses through optimization of silica limits during plant startups (Fig 3).
- Boston Edison Co has spent a considerable sum to improve instrumentation, control, and operation of makeup demineralizers, condensate polishers, and chemical-feed systems at the Mystic station. CCIP expenditures at six units totaling $1.2-million, along with investments for condenser retubing, have brought chemistry-related benefits including the following: (1) reductions of 50% or more in demineralizer regenerant-chemical consumption and resin replacement, and in the cost of demin water; (2) reduced wear and tear on regeneration equipment and maintenance on all chemical systems; (3) 75-100% reduction of phosphate, sulfate, and sulfite additive for boilers (Units 4, 5, 6); (4) increase in boiler-cleaning intervals by two to six years; (5) 50% reduction in boiler blowdown and plant heat rate; (6) elimination of outages necessitated by condenser leakage and boiler-tube underdeposit corrosion; and (7) improved plant availability by 3 or 4% minimum.

Note that many other areas considered for economic improvement are not discussed here. Many relate directly to demineralizer and polisher operation, as well as resin choices—for example, uniform resin-particle sizes

How CCIP has profited Pennsylvania Power & Light Co*

Expense source	1989-90 avg	1991	1992	1993
MWh loss from water-chemistry causes				
Boiler-water condition	$314,300	[illegible]	[illegible]	$70,560
High boiler-water silica	145,800	[illegible]	[illegible]	0
Makeup-system problems	35,000	2400	0	0
Feedwater-pH control	1500	170	0	8200
Misc chemistry problems	800	2270	3237	1305
Subtotal	497,400	33,490	58,887	80,065
Emergency portable demineralization service	330,800	156,385	165,890	93,265
MWh loss from waterwall tube corrosion failures	527,000	0	0	0
Total loss	$1,355,200	$189,875	$224,777	$173,330

* Partial results reported by B H Herre at Fourth International Conference on Cycle Chemistry in Fossil Plants, pending completion of system audit

(vs commercial size distribution) to improve regeneration efficiency, use of weakly acidic resin in place of a softener for processing wellwater, upflow vs downflow countercurrent regeneration, elimination of mixed-bed regeneration and associated costs through use of throwaway resin, etc.

Even greater O&M saving may be achieved with the retrofit of a condensate polisher, if one is not already in place. This was found to be the case by Tri-State G&T Assn Inc, for example, when engineers considered a water-treatment upgrade for Craig-1 and -2. Careful cost analysis justified the retrofit—providing dedicated polishers for all three units—on the basis of reduced turbine deposition (75 to 100%), reduced differential power cost during startup, decreased chemical-cleaning costs, and reduced blowdown. A respectable payback period of slightly over two years was their reward. ■

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Chronicling a cost-cutting reverse-osmosis retrofit

Much of today's efforts to optimize water-treatment costs center on the demineralization of makeup water. Many instances are cited delineating such experience, but few more definitively than that of Midwest Power Systems Inc. The utility reports that its George Neal generating stations, located in Sioux City, Iowa, are realizing savings of $1000/day or more in demineralizer operating costs following the addition of a pretreatment system featuring reverse-osmosis (RO) membranes. The new system has significantly reduced the amount of caustic and acid needed for periodic regeneration of ion-exchange (IX) resins used to purify the stations' makeup water.

The stations comprise Neal North, where three coal-fired generators use 230,000 gal/day of water to produce 954 MW, and Neal South, two miles away, which uses 160,000 gal/day and generates 624 MW. The North and South plants have separate wells and independent demineralizer systems.

The first RO retrofit was made in 1991 at Neal South by the plant staff, with technical assistance from Coster Engineering, Mankato, Minn, and TCI Inc, Allen, Tex. The attractive payback for the modification led to a similar change at the other unit the following year, where an RO system manufactured by Coster was installed (Table 1).

Midwest Power may extend the use of RO technology to other plants in its system. Explaining that all of the utility's plants face soaring water-treatment costs and increasing regulation for handling of chemicals, project engineer John Uphoff states, "RO makeup treatment is environmentally friendly, and has reduced our hazardous-chemical requirements by approximately