Costlier, scarcer supplies dictate making thermal plants less thirsty

The Energy Information Administration estimates that U.S. thermoelectric generating capacity will grow from 709 GW in 2005 to 862 GW in 2030 to help meet annual demand increases of 2%. The makeup and cooling water needed by plants generating that increased capacity certainly won't be available from withdrawal sources, so plant developers and owners will have to apply water-stingy technologies plantwide. As is usually the case, conservation saves money as well as the environment. Here's a thumbnail economic analysis of some solutions to the water problem.

By Dr. John R. Wolfe, PE, Limno-Tech Inc.

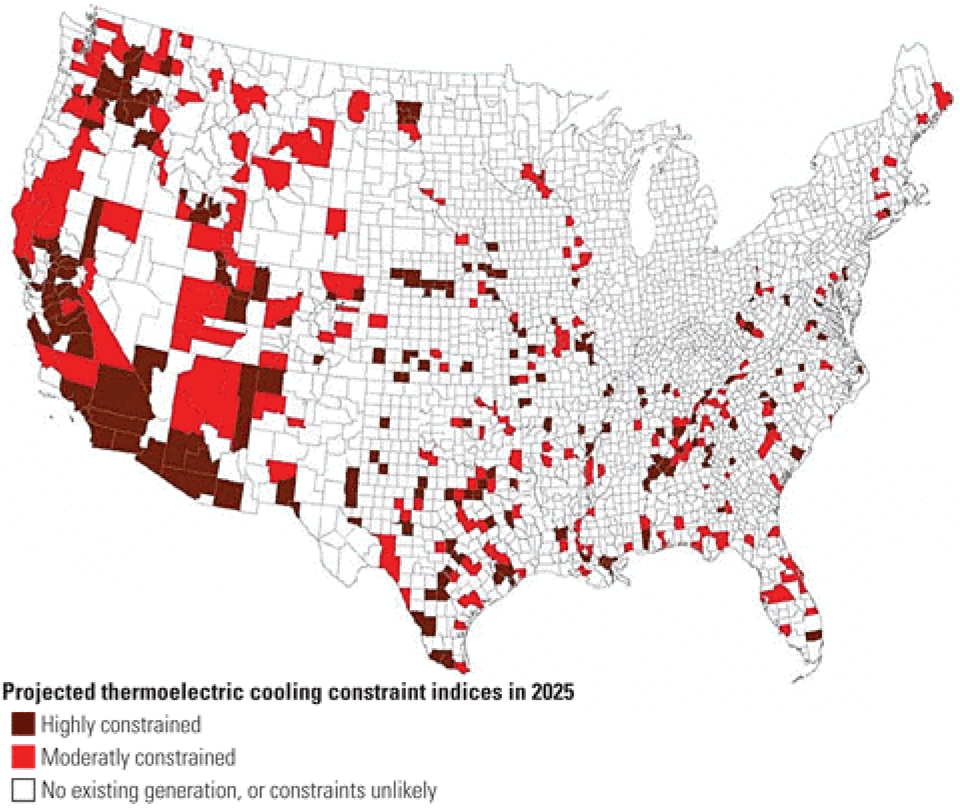
When the well's dry, we know the worth of water," wrote Benjamin Franklin in *Poor Richard's Almanac* (1746). Power plant owners are becoming very familiar with that economic lesson.

The electric power industry requires reliable supplies of water in large quantities for cooling and—to a lesser extent—for flue gas desulfurization and ash handling. Water use remains a contentious issue for the U.S. industry, whose plants account for 40% of freshwater withdrawals nationwide but only 3% of freshwater consumption, according to a 2004 U.S. Geological Survey (USGS) report.

As America's population and electricity use continue to grow, power plants are increasingly competing with farms, factories, businesses, and households for limited supplies of water. Because the growth of fresh water supplies is limited, growth in electricity demand can be met only by developing technologies that reduce the volume of fresh water required per kilowatt-hour of power generated.

Power generators have a vested interest in conserving water to make local and regional supplies last longer. Doing so helps guarantee not only future plant operations but also a growing economy with greater electricity demand.

In a 2006 report, the National Energy Technology Laboratory (NETL) projected that the lion's share of the new capacity installed between 2005 and 2030 will be in arid regions, including southeast, southwest, and western states. Those are the areas where adopting new water-conserving technologies will likely be most cost-effective for plant operators, due to the shrinking availability and the rising cost of water there (Figure 1).



1. Supply vs. demand. The Thermoelectric Cooling Constraint Index is based on the Water Supply Sustainability Index (WSSI), which takes into account the amount of available renewable water and sustainable groundwater use, limits on freshwater withdrawals needed to protect endangered species, an area's susceptibility to drought, and its expected growth in water use and power production. An area is considered highly constrained if its WSSI is 3 or greater and moderately constrained if its WSSI is between 2 and 3. Source: NETL, 2006

The purpose of this article is not to review all the available conservation technologies but rather to introduce their potential cost savings to power developers. Another aim is to challenge the original equipment manufacturing community to produce engineered products that minimize water consumption and/or use.

Though existing plants can benefit from retrofitting new technologies, the greatest potential cost savings lies in integrating new technologies into new plant designs. The longer amortization period of investment in new plants makes new technologies more attractive for those plants.

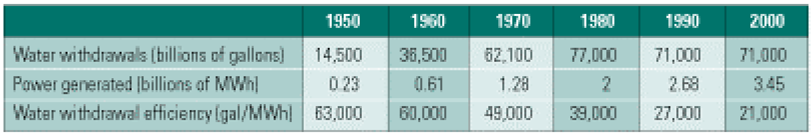
Open- vs. closed-loop cooling

Not all water withdrawals result in consumptive use, and this distinction is especially important for the electric power industry. Many older plants use once-through cooling, which heats large volumes of water and then returns that water, with little volume loss, to a river, a lake, or an ocean.

As a result of Clean Water Act Section 316(b) provisions and public pressures, most jurisdictions now discourage or prohibit construction of new once-through cooling systems. A 2002 EPRI report found that a typical system at a plant burning a fossil fuel, biomass, or waste requires withdrawals of 20,000 to 50,000 gallons/MWh, although it only consumes (loses) 300 gal/MWh. However, the large volume of water withdrawn by a once-through system can entrain and impinge aquatic organisms, and the discharge of heat to surface waters may have adverse ecological effects. Once-through systems may be retrofitted with helper towers or use groundwater to dilute discharge and mitigate temperature problems.

For new installations, closed-loop (recirculating) cooling systems are increasingly required. Because recirculating systems cool by evaporation from towers or cooling ponds, they consume more water than once-through systems, but they withdraw a lot less. The actual rates of water withdrawal and consumption depend on the plant's generation technology and environmental conditions. But for a typical plant, as described in the previous paragraph, a closed-loop system would require withdrawals of just 500 to 600 gal/MWh and lose 480 gal/MWh to evaporation, according to the 2002 EPRI report.

The changing mix of once-through and recirculating cooling systems—as well as water-conserving improvements to them—enabled the electric power industry to reduce its water withdrawals per unit of power generated by a factor of three over a 50-year period: from 63,000 gal/MWh in 1950 to 21,000 gal/MWh in 2000 (Table 1). Over the same period, power generation increased by a factor of 15.



	1950	1960	1970	1980	1990	2000
Water withdrawals (billions of gallons)	14,500	36,500	62,100	77,000	71,000	71,000
Power generated (billions of MWh)	0.23	0.61	1.28	2	2.68	3.45
Water withdrawal efficiency (gal/MWh)	63,000	60,000	49,000	39,000	27,000	21,000

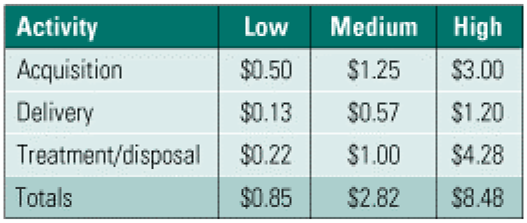
Table 1. Water use efficiency. These were the historical generation and water withdrawal and efficiency values for closed-loop cooling systems serving U.S. coal-, biomass-, and waste-fired power plants. Sources: USGS and EIA

Clean water: No longer abundant or free

The siting of new plants or the expansion of existing ones is dictated by electricity demand forecasts. The choice of cooling technology and other decisions affecting water use are part of an overall siting and plant design process, although location and fuel availability are usually more powerful drivers than water availability. Next on the list of desirable features is a site that has sufficient transmission access and transportation facilities to supply fuel at an attractive price. These selection factors should be familiar to anyone following the number of large coal projects under development in arid regions of the western U.S.

Recent projects tend to assume that water is available at some price. One developer in the Southwest noted that, “The cost of water is not an important factor for us, except when water is unavailable at any price.” Another, in the Southeast, said, “Water is more and more critical, more in terms of availability than cost.” A third developer, who specializes in expanding existing plants rather than building new ones, noted that “The cost of water is going up, and water from watersheds is over-appropriated. There is a tendency to expand at existing sites where water is available.”

The cost of acquiring water depends on its local abundance or scarcity, water rights, and use rules. Where water is abundant and local regulations permit, the cost of acquiring water for a new plant may be limited to investing in wells or surface water intakes. Preventing fish entrainment and limiting impingement mortality may be costly when surface water is used. Water rights laws govern allocation in the West, making water costly and possibly unavailable during droughts. The cost of acquiring water varies widely, from as low as 50 cents/1,000 gallons (kgal), where water is abundant and regulations permit, to as much as $3/kgal where water is very scarce and rights must be acquired from existing owners (Table 2).



Activity	Low	Medium	High
Acquisition	$0.50	$1.25	$3.00
Delivery	$0.13	$0.57	$1.20
Treatment/disposal	$0.22	$1.00	$4.28
Totals	$0.85	$2.82	$8.48

Table 2. Water costs. Here are recent representative costs of acquiring, transporting, and treating/disposing of 1,000 gallons of water. A reasonable range for the overall cost of water is $1/kgal to $4/kgal. Source: EPRI, 2004

The cost of delivering water depends on distance and terrain but varies over a narrower range than acquisition cost. Research shows this component of water cost can be as little as 13 cents/kgal or as much as $1.20/kgal.

The cost to treat and dispose of cooling water varies much more widely, depending on the characteristics of the raw water. Surface water may be suitable for cooling with minimal treatment or may require removal of suspended solids. Because effluent from wastewater treatment plants is typically treated to make it suitable for discharge, it is usually of fairly high quality. However, nutrients and bacteria may restrict wastewater’s use for cooling unless the power plant treats it further (see *POWER*, May 2006, “Recycling, reuse define future plant designs”).

Fresh groundwater has higher concentrations of dissolved solids that can become scale unless they are removed by pretreatment in a closed-loop cooling system. Saline water from the ocean or coastal areas also requires treatment and/or the use of special corrosion-resistant materials to make it suitable for plant use. Degraded waters from coal and oil production may be available, but they have much greater pretreatment requirements. For example, low pH is an issue for water pumped from spent coal mines, and the effluent of oil and gas well operations can have high levels of salts, silica, and hardness. And because recirculating cooling water also concentrates dissolved constituents in cooling tower blowdown, it may need to be post-treated if it is discharged to surface waters.

EPRI's "Comparison of Alternate Cooling Technologies for U.S. Power Plants" (2004) determined that the cost of pre- and post-treating available water can range from as low as 22 cents/kgal (where treatment requirements are minimal) to as much as $4.28/kgal (if the water left over from oil and gas exploration is used).

As Table 2 shows, the sum of the medium estimates of component costs is $2.82/kgal. It is unlikely that a water source would be used if the costs of acquiring, delivering, and treating/disposing of it were all at the high or low end of their ranges; a reasonable range for the overall cost of water is $1/kgal to $4/kgal.

This wide range of water costs has important implications for the sustainability of supplies. Because costs vary widely from one location to another, so does the attractiveness of water conservation technologies across locations and regions. The development of new technologies increases the options for plant developers and decision-makers, enabling them to reduce water-related costs and plant profitability.

Better cooling options can even make it easier to site a plant near its market and fuel supplies, potentially boosting profits. Ideally, water availability and cost should not be second-tier considerations during the planning of a power project; they should be as important as electricity demand and fuel availability. When more technological options—plus more-reliable information about water supplies and costs and the economic benefits of new technologies—are available, planners can do a better job of planning and siting new capacity to use water supplies wisely.

Recycling water

As mentioned earlier, closed-loop cooling systems require less fresh water withdrawals than once-through systems, but they consume more water due to evaporation. In addition, water may be consumed by flue gas scrubbing and be lost to cooling tower blowdown. The development of new technologies could reduce losses from each of these processes, as could the reuse of "gray water" for cooling.

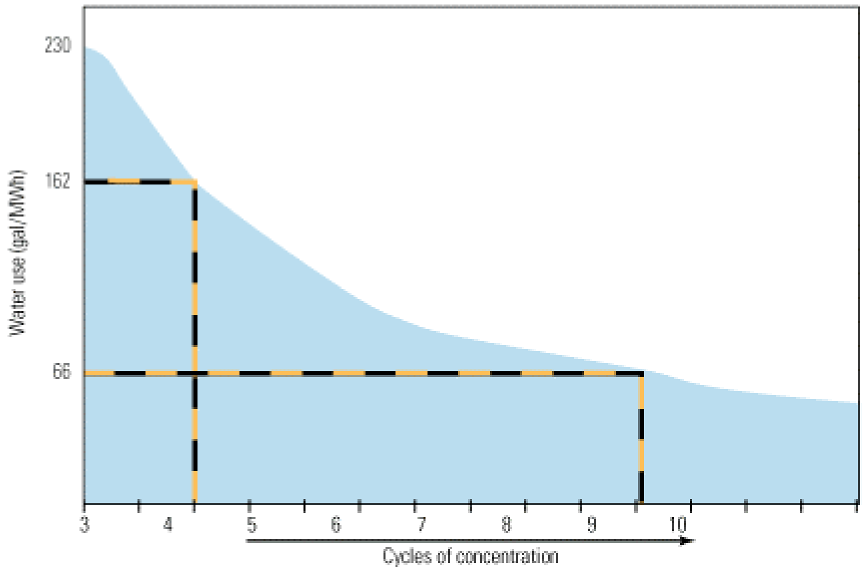
The 480 gal/MWh loss to evaporation from a typical coal-fired power plant represents the greatest opportunity for savings. Evaporative losses can be reduced if water vapor can be condensed and returned to the cooling system. Small-scale tests of one technology, which uses crosscurrents of ambient air for condensation, show potential for capturing 12% to 30% of evaporative losses if engineered to full scale. A 2006 paper by Ken Mortenson argued that this technology could cut losses by 60 to 140 gal/MWh, with the high end applying to hotter climates.

This reduction in water losses can be translated into dollar savings at the plant level by assuming a cost of water and a plant capacity. Using the representative midrange total water cost of $2.82/kgal developed earlier, the savings would range from $0.17 to $0.39/MWh. For a 350-MW baseload plant operating year-round, savings from reducing evaporation from its cooling towers would amount to between $500,000 and $1,200,000, with a midrange value of $870,000. Increasing the towers' cycles of concentration and reducing blowdown losses (see below) might save the same plant another $300,000 to $1,200,000 annually.

Beware of blowdown

As water evaporates from a cooling tower, the concentrations of dissolved and suspended solids in the remaining water increase. To minimize scaling, fouling, and corrosion of the cooling system, these concentrations are reduced by blowdown. Blowdown is the term for the discharge of water from the cooling system and its replacement by fresh makeup water taken from a river, lake, or well. The term "cycles of concentration" describes the proportion by which evaporation increases constituent concentrations (assuming the typical evaporation rate of 480 gal/MWh). For example, at two cycles of concentration, evaporation doubles constituent concentrations, relative to intake water.

The development of cooling system materials that are resistant to scaling, corrosion, and fouling may make it possible to operate at higher solids concentrations, significantly reducing blowdown losses. A study by EPRI and the California Energy Commission found that doubling cycles of concentration from 4 to 8, which exceeds the usual allowable range, could reduce blowdown by about 100 gal/MWh (Figure 2). (See the *POWER* articles, "Southern California Public Power Authority's Magnolia Power Project" in September 2005 and "High Desert Power Plant" in September 2003, for examples of plants running high cycles-of-concentration cooling towers with zero liquid discharge systems.)



2. Blowdown blowup. Typical water losses from cooling towers at various cycles of concentration. Source: EPRI, 2007

As we did for reductions in evaporative losses, we can translate reductions in blowdown water losses into dollar savings at the plant level by assuming a cost of water and a plant capacity. Using $1 to $4/kgal for the total water cost range, savings from reducing blowdown losses would come in at 10 to 40 cents/MWh. As mentioned earlier, for a 350-MW baseload plant operating year-round, the potential savings would be $300,000 to $1,200,000, with a midrange value of $860,000.

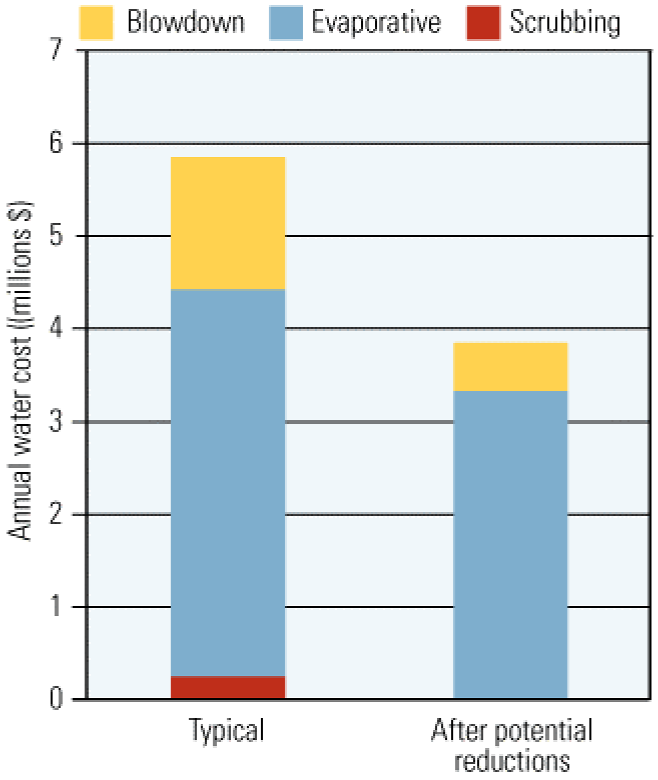
Scrubbing water

The ratcheting down of emission levels for sulfur dioxide has sparked a mini-boom in the market for flue gas desulfurization (FGD) systems, or scrubbers. NETL estimates that the size of the U.S. FGD market is expected to increase by more than 100,000 MW over the next 10 years. Although water requirements for scrubbing are a fraction of those needed for cooling purposes, FGD units require a significant amount of water to produce and handle the various process streams (limestone slurry, scrubber sludge, and the like). NETL's 2005 "Power Plant Water Usage and Loss Study" found that makeup water requirements for the FGD island at a 550-MW (nominal) subcritical coal-fired power plant are about 570 gallons/minute (gpm), vs. about 9,500 gpm for cooling water makeup.

Flue gas scrubbing can be accomplished with either dry or wet systems. Wet scrubbers entrain the flue gas in a water spray, capturing sulfur dioxide and other pollutants, which are then removed by creating an alkaline slurry. Dry scrubbing injects the alkaline particles directly into the flue gas stream, obviating the need for water, but the more limited contact between reactants in the absence of water results in lower pollutant removal efficiencies.

New technologies that reduce or recover evaporative losses from scrubbing flue gas, or increase the removal efficiency of dry scrubbing, could reduce water use and associated costs. Another way to quantify the water requirements for a typical wet scrubber is to determine the amount of water that a plant could save by shifting from wet to dry scrubbing, or by capturing all of the evaporation produced by wet scrubbing. NETL came up with a figure of 25 gal/MWh. Again using $1 to $4/kgal as the range of total water costs, the savings would amount to 2.5 to 10 cents/MWh. For our 350-MW baseload plant operating year-round, the potential annual savings from shifting from wet to dry scrubbing ranges from $75,000 to $300,000, with a midrange value of $220,000.

If all three loss processes (evaporation from cooling towers, blowdown, and flue gas scrubbing) could be simultaneously reduced at an existing 350-MW coal-fired plant, the total annual cost savings would be $875,000 to $2,700,000 (depending on climate and the cost of water), with a midrange total of $1,950,000. Figure 3 shows the potential savings for each process, assuming an intermediate cost of $2.82/kgal for total water use. Most of the savings are from reducing blowdown and evaporative losses, with the elimination of losses from wet scrubbing a minor contributor.



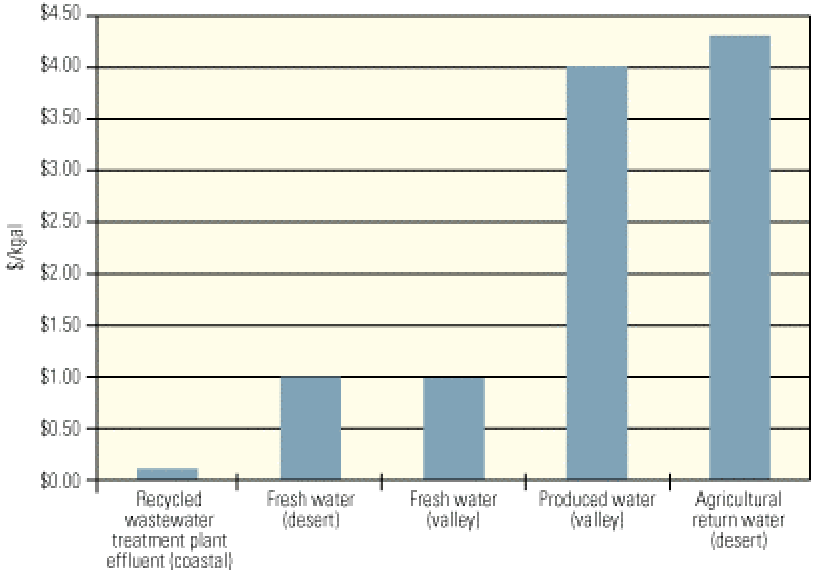
3. Saving water, and dollars. Potential savings from reducing three process water losses at a 350-MW coal-fired power plant, assuming a total water cost of $2.82/kgal. Source: EPRI, 2007

Other sources of water

Where clean water is unavailable at a reasonable cost, lower-quality nontraditional water supplies may be good substitutes, as long as depreciation of cooling systems can be minimized by limited pretreatment of intake waters. Potential sources of degraded water include treated urban wastewater, storm water, mine drainage, quarry dewatering, and water produced by oil and gas extraction (see *POWER,* March 2007, "Reclaimed cooling water's impact on surface condensers and heat exchangers").

Wastewater from public treatment works can be very affordable, at the low end of the treatment/disposal costs shown in Table 2, because such water has already been treated. This water source will also grow sustainably, because growing populations that require more electricity also generate growing wastewater flows. New sewage flows, just from domestic water use alone, can be expected at a rate exceeding 40 gal/day per capita. About 16 gal/day per capita are sufficient for new power generation, assuming current average rates of 33 kWh per day of electricity demand per capita and water consumption for power generation of 480 gal/MWh.

Where population growth is insufficient for increasing wastewater flows, advances in technologies that enable the use of degraded waters may also present substantial opportunities for cost savings. As Figure 4 shows, the cost of treatment required to safely use degraded waters can exceed $4/kgal for produced waters and agricultural return waters, making it the largest component of the cost of water. At such a high cost, use of these degraded waters is not often competitive. However, advances in the ability to use degraded waters without extensive pretreatment—such as spray-enhanced dry cooling—could reduce the overall cost of cooling water, making degraded water competitive with more traditional groundwater and surface water sources.



4. The cost of using degraded water. Representative water treatment costs per 1,000 gallons from various sources. Source: EPRI, 2004

To roughly estimate the potential saving from advances in the use of degraded waters, we can assume a reasonable decrease in the cost of pretreatment, based on the range of current costs. Water resulting from oil and gas extraction, and agricultural return waters, cost $4/kgal or more to treat—about four times what it costs to treat fresh water. It is unlikely that treatment technologies and/or the development of materials compatible with degraded waters will eliminate the gap. It is possible, however, that the difference in treatment costs could be significantly reduced, by as much as 25 to 75 cents/kgal. For our 350-MW baseload plant that requires 480 gal/MWh, the savings would amount to $370,000 to $1,100,000, with a midrange value of $740,000.

Other cooling options

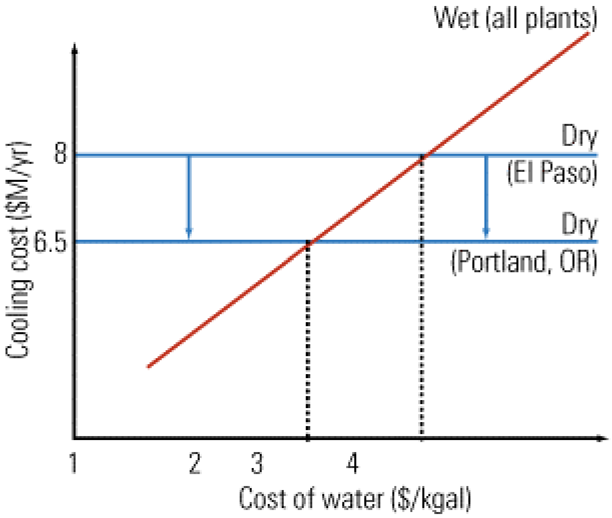
Dry cooling eliminates a thermal power plant's dependence on cooling water. The plant's steam is condensed inside finned tubes by blowing air across their exterior surfaces. The challenges of dry cooling include much higher capital and installation costs, a high efficiency penalty, increased exhaust gas emissions, and load limitations on hot days.

Currently, dry cooling is used, or viewed as an option of last resort, where water is very costly or limited in availability. There are now several plants in operation or under construction that use dry cooling; most are gas-fired, combined-cycle units. As a result, in the U.S. there is only limited experience with dry cooling of baseload-scale plants. Advanced technologies for dry cooling larger plants would be of great interest to power project developers if the technologies would reduce the efficiency and capital-cost penalties.

One developer framed the problem succinctly as follows: "We wouldn't go to dry cooling unless we really had to, because of enormous capital and operating costs, and lower plant efficiency." Efficient air cooling options must be expanded and made less costly for future plants.

Hybrid cooling represents a middle ground that may be more appealing and feasible for baseload plants. Hybrid cooling systems use a combination of both wet and dry cooling technologies to conserve water. Although they decrease the hot weather penalty, they reduce but don't completely eliminate the need for cooling water. Hybrid systems can limit annual water use to 2% to 5% of what wet recirculating cooling systems use, although 20% to 80% is a more typical range. Generation efficiency and capacity generally increase with greater water use.

It is only where the costs of water are highest that air cooling is cost-competitive with water cooling (Figure 5). For example, if our 350-MW reference plant were in El Paso, Texas, dry cooling would be cost-competitive only when the cost of water exceeds about $3/kgal. Above that level, dry cooling would be preferred because its cost is unaffected by the cost of water.

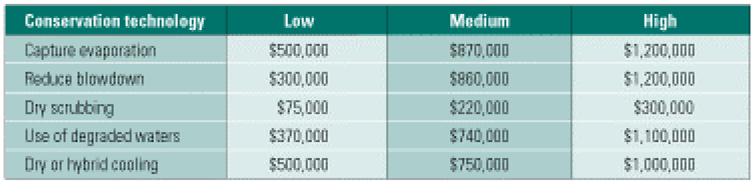


5. Breakeven points. Comparing the costs of wet and dry cooling for two hypothetical 350-MW plants—one in Portland, Ore., and the other in El Paso, Texas. Source: EPRI, 2004

The magnitude of potential savings for generators in warmer climates approaches 20% of cooling costs. Look at the cost curves of Figure 5 for plants in El Paso, Texas, and Portland, Ore. (see *POWER,* September 2007, "Port Westward Generating Plant"). The difference is due entirely to El Paso's hot weather penalty, which is on the order of $1.5 million/year in cooling costs, according to a 2004 EPRI report. The goal of ongoing research into improved air-cooled and/or hybrid technologies is to reduce costs for a plant of this capacity by a significant share. A reduction of 33% to 66% in the hot weather penalty would produce annual savings of $500,000 to $1,000,000.

Running the numbers

Potential cost savings have been estimated above for several innovative applied technologies. To provide a consistent point of reference, Table 3 can be used to roughly estimate the potential annual cost savings available to a typical 350-MW coal-burning plant from capturing evaporation, reducing blowdown, using degraded waters, and adopting dry or hybrid cooling.



Conservation technology	Low	Medium	High
Capture evaporation	$500,000	$870,000	$1,200,000
Reduce blowdown	$300,000	$860,000	$1,200,000
Dry scrubbing	$75,000	$220,000	$300,000
Use of degraded waters	$370,000	$740,000	$1,100,000
Dry or hybrid cooling	$500,000	$750,000	$1,000,000

Table 3. Cost savings. These are the estimated annual benefits for a typical 350-MW coal-burning plant from using different water use reduction technologies. Source: EPRI, 2007

Any of the estimated savings shown in the table would be sizable enough to significantly increase a power plant's profitability. For example, the production costs of a 350-MW baseload coal-burning plant run about $100 to $125 million annually, based on a levelized cost ranging from $33 to $41/MWh. With the exception of dry scrubbing, each technology listed in Table 3 has the potential to reduce annual production costs by about 1%, increasing profitability by the same percentage.

Because profit rates for generating plants currently average about 7% to 8% of costs, implementing these water-conservation technologies, alone or in combination, could raise profit rates by 1 to 3 percentage points, from 7% to 8% to an improved 8% to 11%. Measured in millions of dollars, that's a substantial gain.

Water usage research

For more information about the subject of power plant water usage, consult the following sources, which informed the writing of this article:

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