OPEN MEETING AGENDA ITEM

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From: Bill Powers [bpowers@powersengineering.com]
Sent: Thursday, November 19, 2009 6:29 PM
To: Newman-Web
Cc: Nancy LaPlaca
Subject: comments on proposed amendments to Integrated Resource Plan rules for utilities regulated by the ACC
Attachments: 19-nov-09_Powers Egr_wet-dry & dry cooling_Western power plants.pdf; 2007_Power Engineering_wet dry & in between_Comanche 750 MW.pdf; 01-oct-09_Nat Gas & Elec Journal_Powers_PV pulling ahead, but why pay transmission costs.pdf; 16-nov-09_NYT_solar developer abandons water plans.pdf

Dear Commissioner Newman:

I would like to take this opportunity to support the need for the utility Integrated Resource Plans to include a life-cycle analysis of water use and water pollution by existing and proposed future power generation assets. Dry cooling or parallel wet-dry cooling is now routinely used in Western power plants. Use of dry cooling or parallel wet-dry substantially reduces power plant water consumption, up to 70 percent when parallel wet-dry cooling is used and over 95 percent when dry cooling is used. Cooling tower blowdown wastewater is also substantially reduced when parallel wet-dry cooling is used. It is eliminated when air-cooling is used. Nevada, Colorado, Texas, California, and northern Mexico all have multiple air-cooled and/or parallel wet-dry cooling power plants in operation. Attached is a short PowerPoint with selected examples of Western air-cooled or parallel wet-dry cooled power plants.

I have also attached a March 2007 Power Engineering editorial on the viability/advisability of dry cooling or parallel wet-dry cooling for any new power plant as a hedge against present or future limits on water availability. Power plants do not need water to operate efficiently and economically. Essentially all recent power plants built in Southern Nevada utilize dry cooling. There is no technical or economic reason for Arizona to allocate substantial amounts of water to new power plants constructed in the state. Also, existing power plants can readily be retrofit to parallel wet-dry cooling should the state need to re-allocate much of the water currently consumed by these plants for other water-dependent uses at some point in the future.

Certain types of solar power generation technologies are also major consumers of water, consuming more water per megawatt-hour of power production than either water-cooled natural gas or coal plants. Solar plants can and should be dry-cooled as well. I have attached an October 2009 article I wrote in Natural Gas & Electricity Journal that evaluates the water consumption of various solar technologies. Finally I have attached a November 16, 2009 New York Times article documenting the commitment of a major solar thermal power plant developer to utilize dry-cooling in Nevada. This same developer, Solar Millenium, has also indicated it will use dry cooling for its proposed projects in California.

Please feel free to contact me at (619) 295-2072 or bpowers@powersengineering.com if you have any questions regarding my comments on the proposed amendments to the Integrated Resource Plan rules for utilities regulated by the ACC.

Best regards,

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Arizona Corporation Commission
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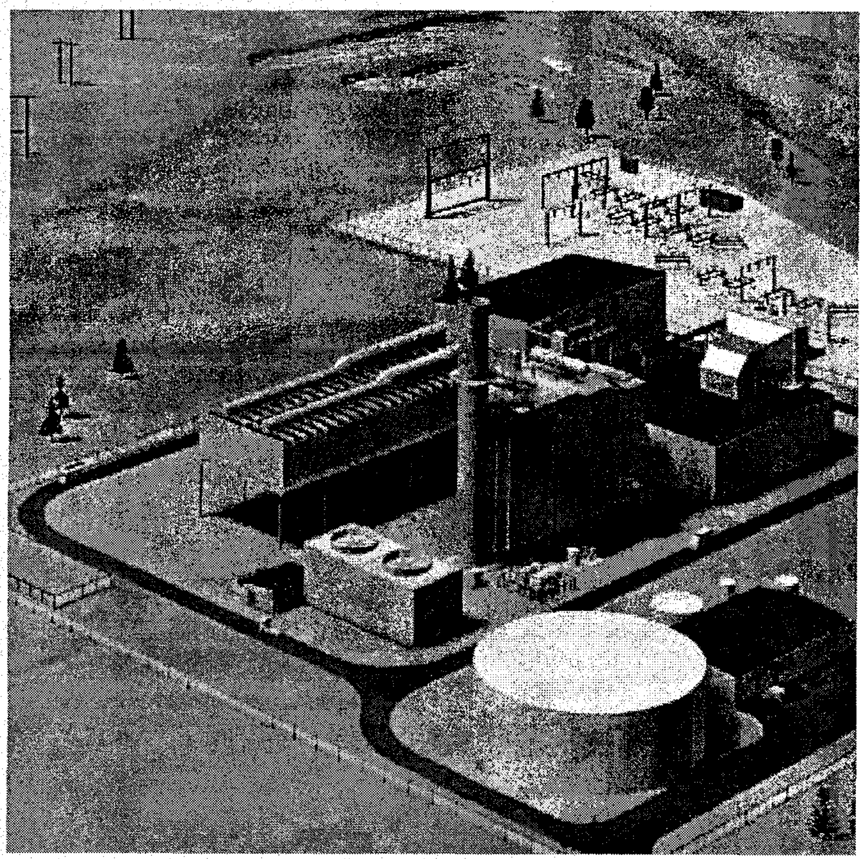
Selected Examples of Wet-Dry and Dry-Cooled Power Plants in the West

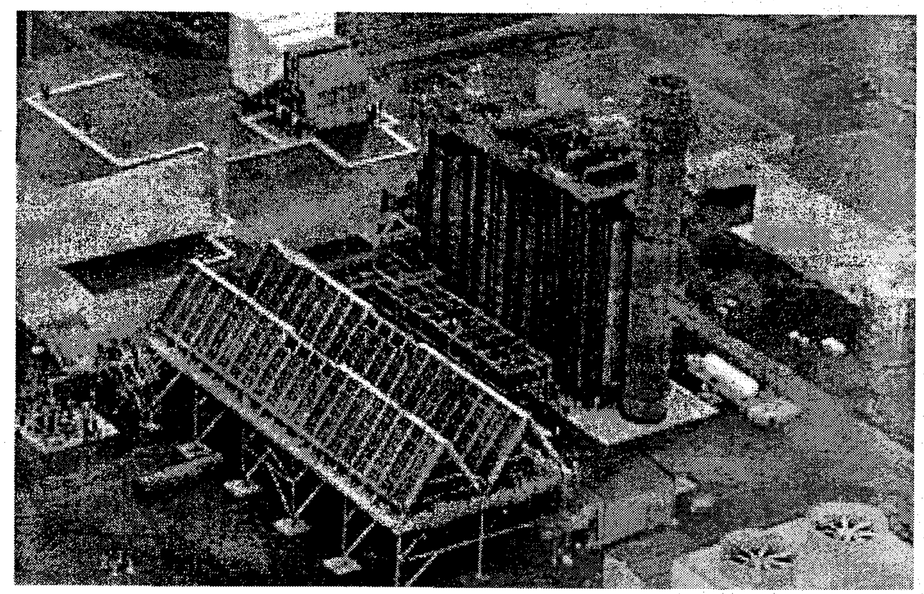
Bill Powers, P.E.

November 19, 2009

Goldendale (CO) 270 MW wet/dry cooled: 1 turbine, 10 dry cells, 2 wet cells

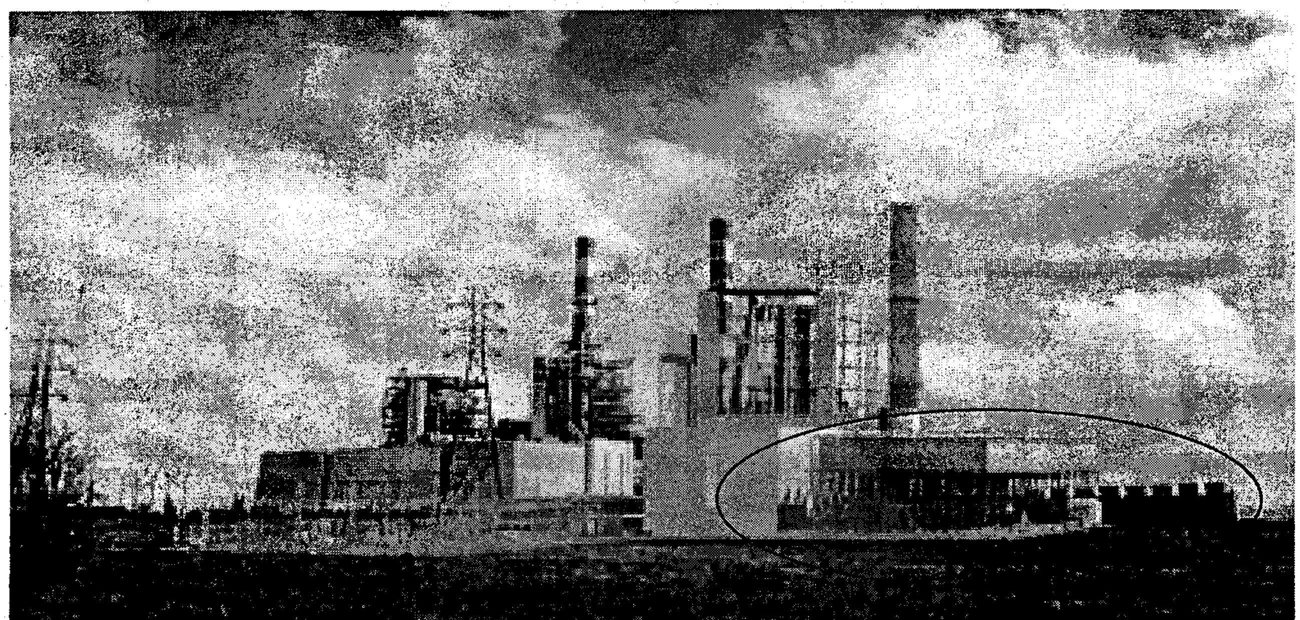
sources: GEA Power Cooling Systems and Calpine Corp. http://www.calpine.com/power/plants.asp#137



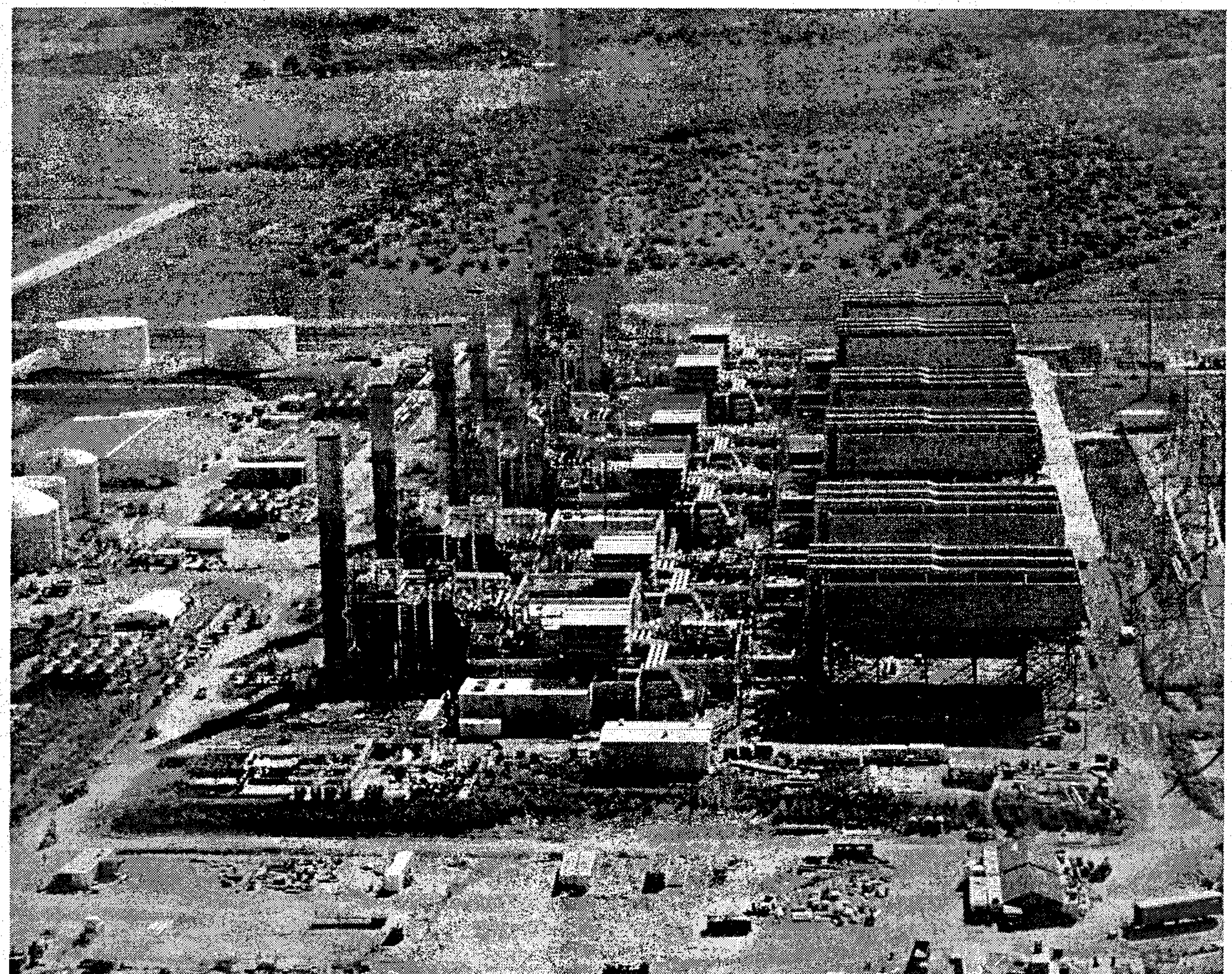


Xcel 750 MW Comanche 3 coal plant (CO) – parallel wet/dry cooling system

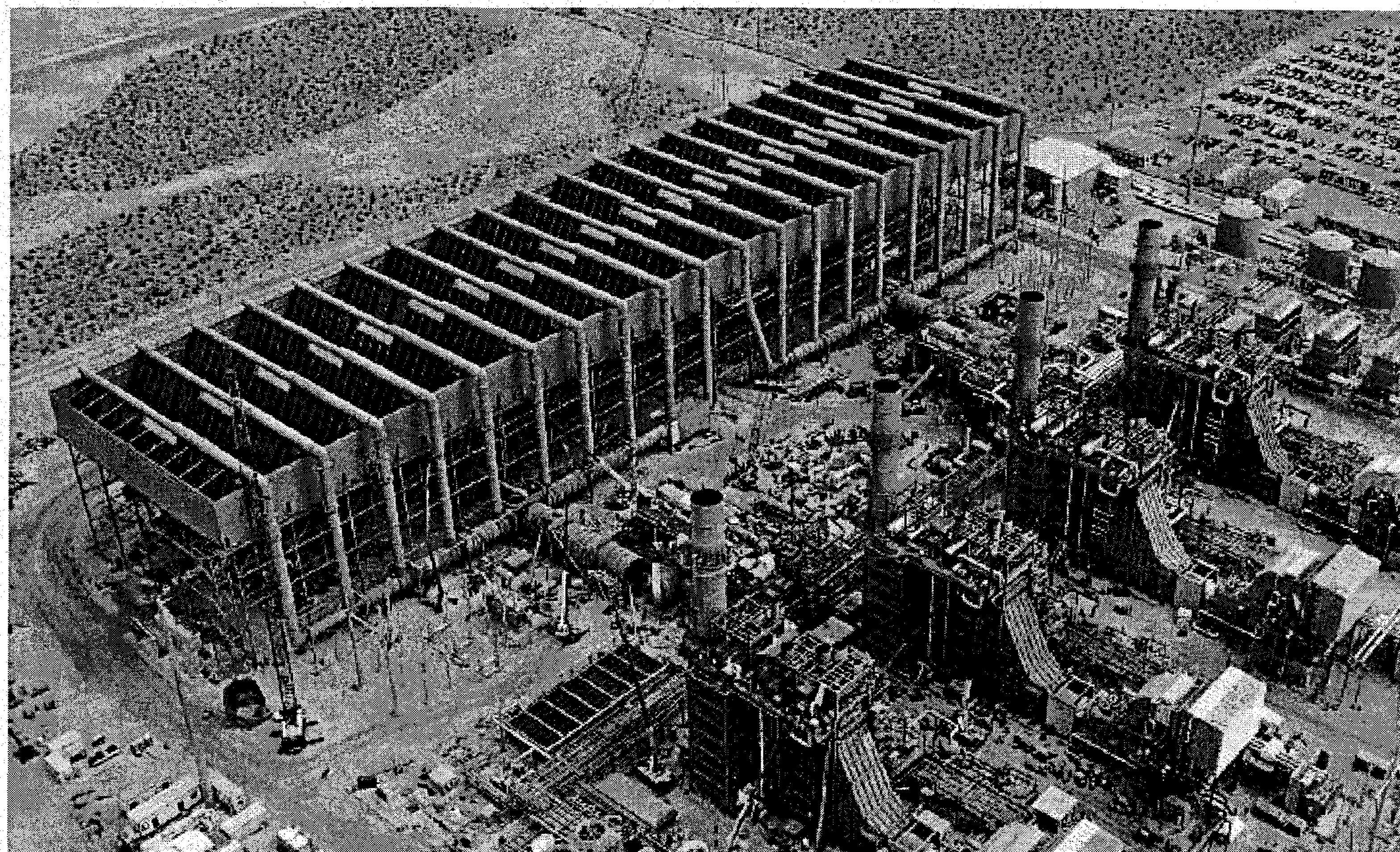
See: http://xcelenergy.com/Minnesota/Company/About_Energy_and_Rates/Comanche%20Unit%203/Pages/Comanche_Unit3.aspx



Midlothian Energy (TX) 1,500 MW air-cooled combined cycle plant



Moapa 1200 MW Combined Cycle (Nevada, USA) Air Cooled Condensers (2 Units)



Operational and proposed dry Nevada projects

Tom Maher, Southern Nevada Water Authority, *Water and Power in Southern Nevada*, May 31, 2002, presented at AWMA Dry Cooling Symposium, San Diego

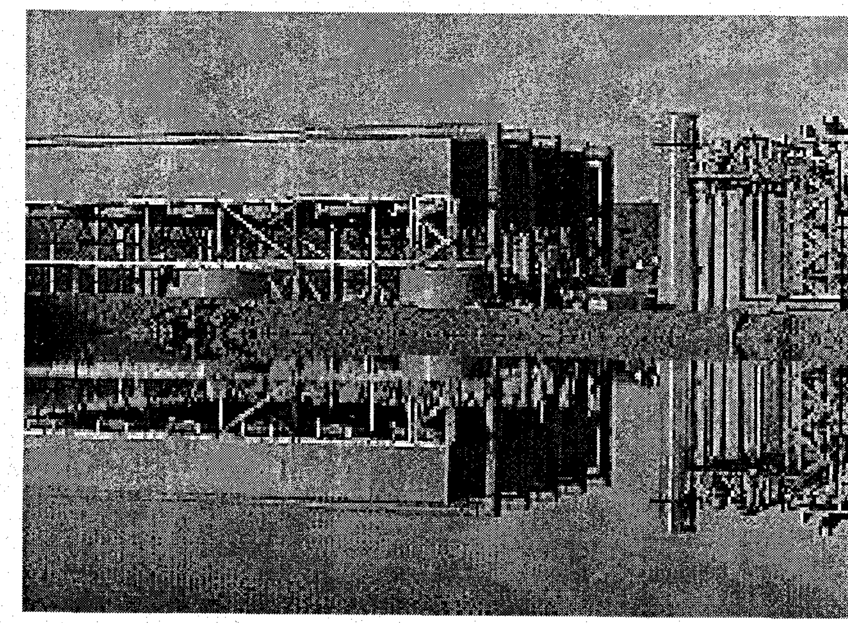
Project	Capacity (MW)	Cooling
B. D. Power Partners	400	None
Calpine	760	Wet
Cogentrix	1100	Wet
Diamond Generating	500	Dry
Duke Energy	1150	Dry
F. Neil Smith & Assoc.	500	Dry
GenWest	500	Dry
Mirant	1100	Dry
Nevada Power	480 (2)	Dry
NV Cogeneration Assoc.	230	N/A
PG&E NEG	1200	Wet
Reliant	500	Dry
Reliant	500 (2)	Dry
Sempra/Reliant	600	Dry
Table Mountain	85	None
Williams Energy	1,000 (2)	Wet
Total	> 10,000	

Sempra 500 MW dry-cooled El Dorado plant in Nevada desert: 2 turbines, 30 dry cells

Note: text and photo from air-cooled condenser (ACC) system manufacturer GEA PCS website, www.geaict.com

ACC is comprised of 30 cells in a 5x6 configuration and was built to meet the following conditions:

- plant came online in 2001;
- 160 MW steam turbine;
- peak site temperature of 117 °F;
- designed for full power output at 1% site temperature (108 °F).



The New York Times
Green Inc.
Energy, the Environment and the Bottom Line

NOVEMBER 16, 2009, 2:47 PM

Solar Developer Abandons Water Plans

By TODD WOODY

Solar Millennium In the face of growing concerns over water use by solar-power plants in the West, a German solar developer, Solar Millennium, has decided to use a dry-cooling method instead. Above, a Solar Millennium farm in Europe.

A solar developer caught in the crossfire of the West's water wars is waving the white flag.

Solar Millennium, a German developer, had proposed using as much as 1.3 billon gallons of water a year to cool a massive solar-power plant complex it wants to build in a desert valley 80 miles northwest of Las Vegas.

That divided the residents of Amargosa Valley, some of whom feared the solar farm would suck dry their aquifer. Others worried about the impact of the $3 billion project on the endangered pupfish, a tiny blue-gray fish that survives only in a few aquamarine desert pools fed by the valley's aquifer.

Now Solar Millennium says it will instead dry-cool the twin solar farms, which would result in a 90 percent drop in water consumption.

"We trust that this decision to employ dry-cooling will accelerate the approval process and enable us to begin construction and stimulate the local economy by December 2010," Josef Eichhammer, president of Solar Millennium's American operations, said in a statement on Monday.

Water has emerged as a contentious issue as dozens of large solar-power plants are proposed for the Southwest desert. Solar Millennium's move is likely to put pressure on other solar developers to follow suit.

Solar thermal plants use the sun's heat to create steam that drives electricity-generating turbines. After the steam is condensed back to water for reuse, it must be cooled. Developers prefer wet cooling, which allows the heat to evaporate, but which requires water to constantly be replenished.

Dry-cooling technology uses fans and heat exchangers to cool the water, but is more expensive and reduces the efficiency of a solar-power plant. Solar Millennium abandoned wet cooling for all its California projects after a local water district declined to supply the 815 million gallons of water one particular solar farm would consume annually.

Not everyone will be celebrating the company's decision to go dry in Armargosa Valley. Some residents and investors had hoped to sell or lease their water rights to Solar Millennium.

Under Nevada's Byzantine water laws, water rights are held separate from a particular piece of property and Amargosa Valley alfalfa farmers — and even the owner of a local casino — expressed interest in doing deals with the company.

But with water off the table, the Amargosa Valley solar projects' odds of obtaining government approval have improved.

That's good news in a county with 15 percent unemployment. Solar Millennium estimates that each solar farm will generate 800 construction jobs and the complex will need a permanent staff of 100 workers.

Wet, Dry and In Between
By Brian Schimmoller, Contributing Editor

In 2004, as part of a least-cost resource plan filing with the Colorado Public Utility Commission, Xcel Energy proposed constructing a 750 MW supercritical coal-fired unit at the Comanche Station near Pueblo, Colo. To win support for the plan from environmental groups, Xcel agreed to a number of renewable, conservation, emissions control and economic development initiatives. A less-publicized part of the plan concerned water availability in the Arkansas River Basin, where the plant is located. Based on regional economic growth projections, the Pueblo Board of Water Works preferred to limit the amount of water allotted to the new Comanche unit.

"Water purchases from the Arkansas Basin for use outside the area are very controversial," says Tim Farmer, Xcel's project manager for Comanche Unit 3, citing rising demand from places as far away as 150 miles. "Since we would have kept the water in the Valley, we probably could have acquired enough water rights for a completely wet cooling system." Xcel, however, decided to contract for a lesser volume of water and install a parallel condensing system from GEA Power Cooling Systems to reduce water requirements for cooling.

Parallel condensing systems unite conventional wet cooling technology with dry cooling technology to reduce water use; the steam exhausted from the steam turbine is split between a steam surface condenser (tied to a conventional wet cooling tower) and an air-cooled condenser (ACC). At Comanche, the split will be about 50-50, resulting in estimated water requirements of 4,750 to 5,550 acre-feet for Unit 3 (750 MW), versus about 9,500 acre-feet for existing Units 1 and 2 (660 MW) at 90 percent capacity factor.

Water concerns are strongest out West, where an arid climate and population growth accentuate competition for water supplies. Many of the dry cooling systems installed in recent years have been west of the Mississippi River. The Eastern half of the country, however, is not immune from water availability concerns. Most new power plants in Massachusetts are dry-cooled, as are many in New York. Further, suburban sprawl in many Eastern states has precipitated demand-driven drought conditions, in which the narrow balance between water supply and demand triggers near-term emergencies and limits longer-term industrial development.

As pressures mount to reduce water consumption or to deal with lower water availability, alternate cooling schemes become more palatable. Parallel condensing systems are one option, but others exist. "Whether you put in a two-cell wet tower as part of a parallel condensing system or 40 cells as part of an all-wet cooling system, you still need air and water permits," says Bill Wurtz, general manager of Dry Cooling, Americas, for SPX Cooling Technologies. "If the permits could invite significant opposition, it might be simpler to absorb the higher up-front cost of the air-cooled condenser and go all dry."

Moreover, the penalties associated with dry cooling may not be as high as some think. Industry consultant Bill Powers, P.E., with Powers Engineering, believes comparisons between wet and dry cooling are often done on an apples-to-oranges basis. For example, in its Technical Development Document for Section 316(b) regulations under the Clean Water Act, EPA applied lesser performance capabilities to ACC systems than to wet systems, resulting in higher heat rate penalties. In general, the lower the design initial temperature difference (ITD) for an ACC system, the greater the heat transfer capabilities, resulting in a larger ACC but a lower heat rate penalty. "The ITDs used for air-cooled coal plants in the EPA analysis are much higher than the ITDs being specified for new coal plants today," says Powers. "Current state-of-the-art ITD for a coal plant is 40 F, and 35 F ITDs are becoming more common."

In analyzing ACC systems, Powers found a much smaller delta between wet and dry systems when compared using similar criteria and when not focusing solely on performance at peak ambient temperatures. Based on publicly available data for Weston Unit 4, a coal plant being built by Wisconsin Public Service, Powers compared wet and dry performance at various temperatures. For an ITD of 40 F, the annual and peak (at 90 F ambient) heat rate penalties were 2 percent and 3.6 percent, respectively, compared to a wet system with an approach temperature of 12 F. For an ITD of 35 F, the annual and peak heat rate penalties fell to 1.5 percent and 2.8 percent, respectively. Because Weston Unit 4 is equipped to fire 3 percent more fuel than rated throughput if necessary, it could sustain its 515 MW rated capacity with an ACC at temperatures up to 90 F.

Inventive Options

For existing plants facing a water crunch, more inventive options may be necessary. One large coal-fired power plant in Wyoming, for example, obtains its makeup water from a reservoir; but growing demand from farmers and residential areas is reducing water availability. There is not enough room to route the steam flow from the turbine to an ACC system, so SPX's Wurtz offers another solution: "By taking the hot water off of the condenser and running it through a set of air coolers in series with the existing wet cooling tower, water use could be trimmed significantly."

Parallel condensing systems and all-dry cooling systems are more expensive than conventional wet cooling systems. The parallel condensing system at Comanche - which includes 45 air-cooled condenser cells, each almost 80 feet from grade to fan deck - will be three times the capital cost of a conventional wet cooling tower system, but 40 percent less than the cost of an all-dry cooling system, according to Xcel's Tim Farmer.

Overall project cost impacts, however, are less severe. Powers pegs the bottom-line impact at around 5 percent of total project cost for an ACC system relative to a wet cooling system. Plant developers siting new plants may be increasingly willing to absorb that 5 percent to remove the risk associated with public opposition and future water availability concerns.

It's a brave new world out there in terms of securing water rights. Wet, dry or in between, your plant can still stay cool.

Power Engineering March, 2007
Author(s) : Brian Schimmoller

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PV Pulling Ahead, but Why Pay Transmission Costs?

Bill Powers

Southern California Edison (SCE) and the Los Angeles Department of Water & Power (LADWP) recently announced plans to construct large remote photovoltaic (PV) arrays using First Solar thin-film technology. SCE has announced two projects totaling 550 megawatts in the Mojave Desert region of Southern California. The LADWP announced a 55-megawatt project in Imperial County, California. There is still a vast backlog of proposed concentrating solar projects in the Southwest. Yet, PV appears to be gaining momentum as the preferred technology for any solar application, whether remote or urban.

ALTERNATIVES COST MORE, USE WATER

Concentrating solar technologies, specifically solar trough, linear Fresnel, power tower, and dish Stirling, have a higher cost of energy (COE) than state-of-the-art PV. In terms of operating and planned projects, the predominant concentrating solar technology is solar trough. The estimated COE for the most recently constructed solar trough plant in the United States, Acciona's 64-megawatt Nevada One, built in 2007, is $0.15 to $0.17 a kilowatt-hour.[1]

The COE for state-of-the-art PV is in the range of $0.12 to $0.15 a kilowatt-hour. Solar trough has very high water consumption relative to conventional power plants on a megawatt-hour basis, at approximately 800 gallons a megawatt-hour.[2] The water consumption of a related solar trough technology, linear Fresnel, is even higher, at about 1,000 gallons a megawatt-hour. PV arrays use approximately 20 gallons a megawatt-hour for panel cleaning. The high water consumption of solar trough and linear Fresnel solar plants is a major impediment to the deployment of these types of solar plants, as the best solar resources are typically in regions with little water.

High water consumption of solar trough and linear Fresnel solar plants is a major impediment to the deployment of these types of solar plants, as the best solar resources are typically in regions with little water.

By way of comparison, a water-cooled combined-cycle plant uses about 200 gallons a megawatt-hour. An air-cooled combined-cycle plant uses less than 20 gallons a megawatt-hour.

Air cooling can be used to dramatically reduce water consumption from solar trough plants, though use of air cooling adds cost and results in a substantial degradation in performance during hot, peak demand periods when the output is most needed. Power towers operate at higher steam temperature than solar trough or linear Fresnel solar plants. The higher steam temperature results in less performance loss when air cooling is used to condense low-pressure steam as it exhausts from the steam turbine.

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One power tower developer, Brightsource, does incorporate air cooling into the standard plant design. Brightsource has yet to build a utility-scale project. For this reason, the cost and performance impacts of using air cooling have not been demonstrated in the field.

Remote renewable energy installations, whether concentrating solar or PV, require transmission lines to reach load centers. Transmission is expensive. The cost of any new transmission needed to move remote solar power to load centers must be included when comparing the cost of remote renewable energy resources and local solar alternatives. New transmission dedicated to transmitting solar power or wind power from remote locations to load centers in the Southwest would have a typical cost in the range of $0.06 a kilowatt-hour.[3] This cost is in addition to the COE for the renewable generation itself. Transmission losses during times of peak demand are in the range of 14 percent, with average losses in the range of 7 percent.[4] This cost is a given and must be attributed to any remote renewable power-generation resource.

Remote renewable energy installations . . . require transmission lines to reach load centers. Transmission is expensive . . . $0.06 a kilowatt-hour.

PV is the one proven renewable technology that can be deployed on a large scale at the point of use at the distribution level, avoiding the transmission cost and transmission losses associated with remote solar or wind resources.

UTILITIES GUARDING MONOPOLY STATUS

Why then are utilities generally not embracing low-cost urban PV as the lead card in a cost-effective and relatively noncontroversial greenhouse gas–reduction strategy? The answer appears to lie in the investor-owned utility business model, which is built upon utility ownership of electricity infrastructure. *Newsweek* effectively captured the essence of the situation in a recent article on the rapid growth in decentralized rooftop PV systems and the slow growth in large, centralized solar plants preferred by utilities:

The disparity has utilities worried about loosing their grip on the country's energy industry, and the $130 billion residential electricity market. In some cases, utilities are actually taking direct steps to thwart rooftop solar. Two weeks ago in Colorado, the state's biggest utility, Xcel, tried passing a surcharge on homes and businesses using rooftop solar power. The public went ballistic, and with pressure from Democratic Gov. Bill Ritter, the proposal was eventually shelved. In early July, New Mexico's biggest utility, PNM, filed an official request to dramatically reduce incentives for businesses and homeowners to install solar panels, and is now fighting with state lawmakers over whether it has the right to exclusively own solar panels systems hooked up to its grid. During California's last legislative session, Southern California Edison, which serves 13 million residents, successfully lobbied against a bill that would have allowed the city of Palm Desert to pay solar users for the excess power they generate. (Phillips, M. [2009, August 25]. Taking a dim view of solar energy—Who could possibly be against homeowners using solar panels to power their homes? Utility companies. *Newsweek*, http://www.newsweek.com/id/213468)

When new transmission costs and line losses are considered, rooftop PV remains a more cost-effective value proposition.

Utility concern that rooftop PV owned by third parties may become the default renewable portfolio standard compliance strategy in the Southwest, given the difficulty the utilities have had in moving forward on concentrating solar projects, may be one factor in the recent trend toward more large, remote PV projects. However, when new transmission costs and line losses are considered, rooftop PV remains a more cost-effective value proposition. Resistance to the development of huge greenfield solar arrays on desert lands—whether PV or any other type of solar energy—and to the cost and environmental impacts of associated transmission may yet require utilities to ease their grip on electric power production and delivery as the pace of rooftop PV development accelerates.

NEED TO REDUCE WATER CONSUMPTION IN SOLAR THERMAL PLANTS

The U.S. Department of Energy (DOE) is engaged in an ongoing effort to evaluate and reduce water consumption in concentrating solar plants.[5] All operating solar thermal plants in the United States use evaporative water cooling. The use of water for power-plant cooling is increasingly controversial in the Southwest due to chronic water shortages.

All operating solar thermal plants in the United States use evaporative water cooling.

Evaporative water cooling is commonly used with fossil power plants, using a cooling tower, to reject the steam-cycle heat. A typical water-cooled coal plant or nuclear plant consumes 500 gallons of water per megawatt-hour of electricity generated. This is similar to the water consumption by a power tower. A water-cooled, combined-cycle natural gas plant consumes about 200 gallons a megawatt-hour. A water-cooled parabolic trough plant consumes about 800 gallons a megawatt-hour. Of this, 2 percent, approximately 20 gallons a megawatt-hour, is used for mirror washing.

Air cooling, in the form of an air-cooled condenser, is being used with increasing frequency in new fossil plants as an alternative to conventional evaporative cooling. The air-cooled condenser is similar in design to an automotive radiator. The primary advantage of the air-cooled condenser is that it dramatically reduces power-plant water usage, dropping it by 90 to 95 percent or more. An air-cooled combined-cycle plant consumes on the order of 10 to 20 gallons a megawatt-hour.

Numerous combined-cycle plants have been built in southern Nevada in recent years, and all of them use air-cooled condensers for cooling. The reason for this is the severe shortage of discretionary water supplies in southern Nevada.

The El Dorado 480-megawatt air-cooled combined-cycle plant owned by Sempra Generation is adjacent to the water-cooled 64-megawatt Nevada One solar plant that came online in June 2007. The Nevada One solar trough plant produces only a small fraction of the power output of the Sempra plant on an annual basis, approximately 5 percent,[6] yet consumes significantly more water than the combined-cycle plant.

Sempra Generation built a 10-megawatt PV array at the site of the El Dorado combined-cycle plant, using state-of-the-art First Solar thin-film PV. The PV plant came online in December 2008. Sempra Generation CEO Michael Allman states that the PV array produces the lowest-cost solar energy ever generated from anywhere in the world.[7] He also indicates that Sempra evaluated solar thermal technologies and determined that PV is a more cost-effective option.

TYPES OF CONCENTRATING SOLAR TECHNOLOGIES

There are four primary concentrating solar plant designs—solar trough, linear Fresnel, power tower, and dish/engine. All designs use a small amount of water for mirror washing. The first three of these technologies operate a steam cycle and require some water for steam makeup and, when they are water-cooled, require a substantial amount of water for heat rejection similar to water-cooled fossil and nuclear plants.

Currently, approximately 400 megawatts of solar trough power plants, including the 64-megawatt Nevada One plant, are in operation in the United States. In typical solar trough applications, oil flowing through the receiver tube is heated to about 750 degrees Fahrenheit and used to boil water to produce steam. The resulting steam is used in a conventional steam boiler plant Rankine power cycle and expanded through a turbine connected to an electric generator. The exhaust steam is cooled and condensed back to liquid water to be recirculated in the cycle. The condensers can be either water-cooled or air-cooled, or a hybrid combination.

The DOE reports that the use of air cooling on a solar trough plant reduces output approximately 18 percent during the hottest 1 percent of annual operating hours. The 18 percent reduction in output also represents power that is not available to meet critical peak demand.

Linear Fresnel is in essence a subcategory of solar trough. Tracking mirrors focus on a fixed

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receiving tube where water is boiled directly, producing saturated steam at about 535 degrees Fahrenheit, which powers the steam cycle. Linear Fresnel has lower efficiency than solar trough, though it is expected to cost less due to a simpler design. Today there are no operating linear Fresnel power plants in the United States. As a result of the lower cycle efficiency, linear Fresnel is projected to have a higher cooling water requirement than solar trough.

Power towers use tracking mirrors, called heliostats, to reflect solar energy on a receiver located on a centrally located tower. The solar energy is absorbed by the working fluid, either pressurized water or molten salt, flowing through the receiver. Power towers operate at significantly higher temperatures than solar trough or linear Fresnel. As a result, the performance of the power tower is less affected by the use of air cooling. DOE reports a 6 percent reduction in output for power towers during the hottest 1 percent of annual operating hours.

As noted, one power tower developer, Brightsource, incorporates air cooling in the standard plant design. Some studies have found that this technology has potential for lower costs than solar trough or linear Fresnel collectors, but this is only for large plant sizes. No utility-scale power tower plants have yet been built in the United States.

The dish/engine concept uses a field of individual parabolic-shaped dish reflectors that each focus sunlight onto an engine/generator that used the Stirling thermodynamic cycle to directly produce electricity without producing steam. Unlike solar trough or linear Fresnel plants, dish/engine arrays can be installed on uneven land. There are six 25-kilowatt prototype dish/engine prototype units at Sandia National Laboratory. An ongoing challenge with this technology has been maintaining an effective seal on the hydrogen working fluid. The dish/engine is air-cooled and requires water only for periodic cleaning of the reflecting surfaces.

PV WINNING THE RACE

PV seems to be edging ahead of concentrating solar technologies for remote centralized solar applications. The move to PV for remote arrays appears to be an effort by utilities to regain some control over the development of solar energy, which has rapidly expanded principally in the form of distributed rooftop PV owned by third parties. It is unclear whether this effort will be successful.

PV seems to be edging ahead of concentrating solar technologies for remote centralized solar applications.

Remote centralized renewable energy projects face a number of similar hurdles—competing uses for large tracts of undeveloped desert land, the high cost of new transmission, the difficulty in siting new transmission, and the line losses associated with moving remote renewable energy to load centers. Locating the PV in the urban core is the least-cost solution and eliminates the negative aspects of remote development. Even the switch to PV for remote centralized solar plants by utilities may not substantially alter the dynamic that favors distributed rooftop PV over the remote alternative.

NOTES

1. Peltier, R. (2007, December). Nevada Solar One, Boulder City, Nevada. *Power,* http://www.powermag.com/issues/cover_stories/Nevada-Solar-One-Boulder-City-Nevada_230.html.
2. U.S. Department of Energy (U.S. DOE). (2009, July 16). Concentrating solar power commercial application study: Reducing water consumption of concentrating solar power electricity generation. Report to Congress, http://www.nrel.gov/csp/pdfs/csp_water_study.pdf.
3. California Public Utilities Commission Application A.06-08-010, SDG&E Phase I Opening Brief, Exhibit 142, p. 50. The total revenue requirement for a proposed 1,000-megawatt Sunrise Powerlink transmission line Southern Route is $149.8 million a year over a 58-year cost recovery period. Assume that the capacity factor of 1,000 megawatts of solar trough resources interconnected to the transmission line is 0.29, per the August 2008 Renewable Energy Transmission Initiative Phase 1A final report (www.reti.org). Under this scenario, the transmission line transmits 1,000 MW x 8,760 hr/yr x 0.29 = 2,540,400 MWh/yr. Cost of transmission = ($149,800,000/yr)/(2,540,400 MWh/yr) = $59/MWh ($0.059/kWh).
4. D. Kondoleon, transmission program manager, California Energy Commission, e-mail communication, January 30, 2008.
5. See note 2.
6. This assumes the solar plant operates at a 29 percent capacity factor and the combined-cycle plant operates at a 70 percent capacity factor.
7. Wan, U. (2009, April 22). Sempra wants 300 MW plus of solar in Arizona. *GreenTechMedia,* www.greentechmedia.com/articles/read/sempra-wants-300-megawatts-plus-of-solar-in-arizona-6074/.

