Thermal Power Plant Cooling

Context and Engineering

Edited by
Carey W. King, Ph.D.

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The University of Texas at Austin

ASME

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Preface

ASME is committed to providing engineering solutions for the benefit of human kind, including the identification of methods to improve the efficiency of water usage in thermoelectric power generation and other industrial facilities. The ASME Emerging Technology Committee headed by Joseph Beaman, Ph.D., of the University of Texas, Austin, first identified energy-water nexus as a multidisciplinary focus area for ASME. Subsequently, the Strategic Planning Committee (SPC) led by Chinh Bui, Ph.D., P.E., of UTC Aerospace Systems, and Raj Manchanda, ASME Emerging Technologies, developed a portfolio expansion plan that included the engagement of various experts on the subject within ASME Divisions and other external organizations. Additionally, a stage-gate review process was developed to evaluate and validate the emerging area of Energy Water Nexus (EWN) Technology.

The ASME Center for Research & Technology Development's (CRTD) Research Committee on Water Management Technology, led by Michael Tinkleman, Ph.D., ASME staff, must also be acknowledged for their role in engaging and validating the energy-water arena for the Society. Sriram Somasundaram of Pacific Northwest National Laboratory led the early EWN Task Force, and ultimately, Mike Hightower of Sandia National Laboratories, who transformed the SPC Energy-Water Nexus Task Force into the Energy-Water Nexus Interdisciplinary Council, led it

To build ASME's multidisciplinary community in the energy-water nexus space, ASME Emerging Technologies facilitated the development of knowledge dissemination products and services, including conference technical sessions, webinars, and articles to further explore industry needs. As an additional step to accomplish ASME's objectives within the energy-water nexus, in 2011 ASME Standards and Certification conducted a survey among engineers working in power plants and other industrial facilities heavily dependent upon water usage to determine the need for technical guidance documents on the efficient use of water. The survey results indicated a definite need for documents focusing primarily on the areas of overall performance and technology related to the efficient and sustained use of water resources.

In October 2012, the Board on Standardization and Testing and the Standards and Certification Council approved the creation of a standards committee on Water Efficiency Guidelines for Power and Other Industrial Facilities (WEP) and its charter:

"Develop guidance documents to promote the efficient use of water in applications within power and other industrial facilities and to aid in evaluation of technical options. Topics include, but are not limited to, cooling systems, the use of fresh and non-fresh water resources, and innovative water reuse and water recovery technologies."

As of June 2013, two WEP subcommittees and their charters were established and approved by the Board on Standardization and Testing.
The subcommittee on Innovative Water Conservation, Reuse, and Recovery Technologies:

"To develop guidelines of best practices, performance assessments, and evaluation and reporting criteria in the field of innovative water conservation, reuse, and recovery technologies."

The subcommittee on the Use of Fresh and Non-Fresh Water Resources:

"To develop guidelines describing the aspects of facility development based on water resources availability. This includes, but is not limited to, providing best practices, performance assessments, evaluation methods, and reporting criteria for optimal use of fresh and no-fresh water."

This book, *Thermal Power Plant Cooling: Context and Engineering,* serves as a vehicle to disseminate the knowledge on current practices in the area of Energy-Water Nexus. It is anticipated that it will be a stepping-stone for practitioners to address their immediate needs while spurring other activities, discussions, and collaborations among ASME and external technical communities. With the help of the WEP committees this may lead to developing additional methodologies to further benefit human kind in water usage efficiency.

Raj Manchanda, Brandy Smith, and Fredric Constantino
ASME

Chinh Bui
UTC Aerospace Systems

Biographical Sketches of Authors

Chinh Bui

Dr. Chinh Bui is a registered professional engineer (P.E.) and a certified NARTE product safety engineer with over 30 years of progressively responsible technical and management experience in areas of design, EEE component application, system reliability, maintainability, and safety management disciplines in the aerospace industry. He currently serves as the Chair of the Interdisciplinary Council and Deputy Technical Group Leader for the Engineering Technical Management Group (ETMG). He is also an active member of the Safety Engineering and Risk Analysis Division (SERAD) Senior Advisory Board. Dr. Bui has held the Chairman position for the Strategic Planning Committee and for the SERAD Division. He has also taught graduate school Engineering, the Professional Engineering (P.E.) review program at Rensselaer Polytechnic Institute, and various engineering disciplines at the University of Hartford.

Dr. Bui is involved with many corporation initiatives and has represented his business at the United Technologies Corporation (UTC) Advanced Studies Advisory Council. He is a Gold certified ITO professor at the UTC ITO University, where he teaches relentless root cause analysis and mistake proofing as part of the UTC corporate quality initiative. He had been selected to attend the UTC Emerging Leader Assessment program and also had served on the Hamilton Sundstrand Management Club in various positions, from Treasurer to Vice-President and President (1999). Dr. Bui is a member of the 360 Federal Credit Union Board of Directors and is currently the Product Safety Authority for United Technology Aerospace Space Systems International, a division of the United Technologies Corporation. Dr. Bui holds a Ph.D. in Organization and Management, M.B.A., M.S. in Computer Engineering, M.S. in Electrical Engineering, and B.S. in Electrical Engineering. Dr. Bui has been Chief Instructor at the JKA Karate Club at Trinity College in Hartford, CT, since 2001.

Richard Carothers

Richard Carothers is a senior undergraduate student of Civil Engineering from Norcross, GA, at the University of Texas at Austin. After completing a B.A. in Religious Studies in 2006 at The University of the South in Sewanee, TN, he became interested in how he could impact his community through engineering. Now planning on continuing his studies at graduate school, his focus of interest is Water Resources and Environmental Engineering. Within the field, Carothers is interested in surface water hydrology, water policy, hydrologic and geomorphologic processes, and statistical methods. His present research explores correlations between climactic and geomorphologic regimes by revisiting a 1957 study by Mark A. Melton.

Mónica Copete Montiel

Monica Copete Montiel works at Westinghouse Electric Spain (WES) as Mechanical and Fluid Systems Senior Engineer for both WES national and international markets. Among others, she holds position as Technical Leader of Innovation and Commercial Projects related to Cooling Systems in Nuclear Power Plants from different technologies.

Previous to Westinghouse Electric Spain, Monica held positions as Head of Production for companies related to Nuclear Medicine. She managed production and development of X-ray medical imaging systems while exploring opportunities such as preclinical systems. Monica Copete holds a Master of Science degree in Control and Robotics, Master of Science degree in Electrical Engineering, and a Bachelor degree in Chemical Engineering. She is currently working on her PhD.

Mark R. Deinert

Dr. Mark Deinert's research centers on problems that fall broadly into the areas of energy and fluid systems. He uses tools from engineering analysis, thermodynamics, statistical physics, and computation to understand problems where dynamics, non-equilibria, and complex structure play an important role. He is particularly interested in systems-level models that give a "big picture" view of a problem. His current projects include developing multiscale models for fluid transport in porous media and their application in understanding phase changes in natural systems, the global hydrologic cycle, and geothermal energy systems. He is also looking at how spatial and temporal variation in the availability of alternative energy sources affects policies that are aimed at increasing their use. Dr. Deinert's work on nuclear energy systems centers on application of nuclear reactor physics to understanding the uncertainty associated with simulations that are done to calculate the time-dependent concentration of radioisotopes in a nuclear reactor core. This, in turn, has significant implications for life-cycle analyses of Advanced Nuclear Fuel Cycles. Dr. Deinert received a Ph.D. in Nuclear Science and Engineering from Cornell University in 2003. Following his postdoctoral work in the Department of Theoretical and Applied Mechanics at Cornell, he joined the faculty of the Cockrell School of Engineering in 2008.

Anna Delgado

Anna Delgado is interested in the critical nexus between water and energy with a focus on developing countries. Currently, she is a consultant for the World Bank Water Unit, providing technical and strategic support to an initiate on Water and Energy. The initiative aims to contribute to a sustainable management and development of the water and energy sectors by increasing capacity on integrated planning and fostering potential synergies. She is also a team member of eLuma.org, an organization whose mission is to ensure that rural electrification provides sustainable development for communities in Sierra Leone. Before joining the World Bank she was a research assistant at the MIT Energy Initiative, focusing her research on the water footprint of electricity generation. Before that she worked in the Technical Operations Division of the Agbar Group (a leading company in the water cycle business), where she participated in projects to coordinate and manage global operations, and in Evalueserve India, where she worked as a Business Analyst in the Business Research Unit. She is also passionate about social entrepreneurship and has been engaged with several initiatives to promote decentralized solar solutions in rural areas. She has an M.A. on Technology and Policy from the Massachusetts Institute of Technology and a B.A. and M.A. in Industrial Engineering from Universitat Politecnica de Catalunya.

Timothy H. Diehl

Tim Diehl is a hydrologist in the Tennessee Water Science Center of the U.S. Geological Survey. His main research areas are water use by thermoelectric power plants and erosion and sediment transport due to land disturbance. He has also studied woody debris in streams and the evolution of wetlands in aggrading alluvial systems. He received his Ph.D. in Civil Engineering, M.S. in Environmental Studies, and B.S. in Botany from the University of Wisconsin–Madison.

Vlad Dorjets

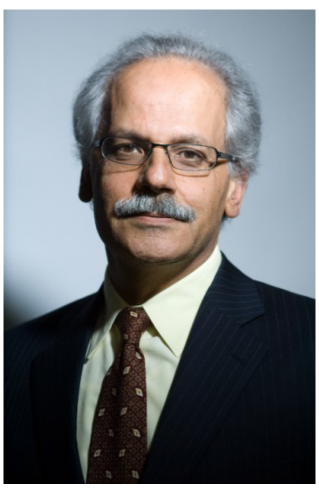
Vlad Dorjets is an economist at the U.S. Energy Information Administration (EIA). Until recently, his primary responsibility was managing the Form EIA-860, "Annual Electric Generator Report," an annual survey of asset-related information submitted by more than 6,000 power plant owners and operators in the United States. As manager of the Form EIA-860, Mr. Dorjets responsibilities included maintaining the form's continued relevance, ensuring the efficient and accurate collection of the related data, and ensuring the data's dissemination in recurring reports, ad hoc analyses, and in response to external inquiries. In addition to his survey-related duties, Mr. Dorjets represented EIA at various efforts relating to the Energy-Water Nexus. This included coordinating with other federal agencies and industry stakeholders, and ensuring that EIA collected the necessary data to meet stakeholders' needs. Mr. Dorjets currently works on forecasting and analysis related to the U.S. coal and nuclear industries.

Prior to joining EIA, Mr. Dorjets spent five years as a power industry consultant, first working on international development projects for Deloitte Emerging Markets, Ltd and then working on process improvement and financial controls for KPMG LLP. Mr. Dorjets received a B.A. in International Studies from Colby College in Waterville, Maine, and an M.A. in International Energy Policy and International Economics from the Johns Hopkins School of Advanced International Studies (SAIS) in Washington, DC.

Louisa B. Eclarinal

Louisa B. Eclarinal, P.G., is an environmental analyst at CPS Energy responsible for strategic water planning, water supply and resources, Edwards Aquifer, and 316 b issues. She has more than 20 years of experience in environmental compliance, including water and wastewater permitting, solid waste management, RCRA permitting, remediation, underground storage tanks, SPCC, and Facility Response Plans. Her background includes utility and consulting work with the Department of Defense, primarily in BRAC closures and property transfers, RCRA site closures, NEPA, and resource management plans. Eclarinal obtained her undergraduate degree in geology from University of Texas at Austin. She is a licensed Professional Geoscientist in Texas, a member of the Air and Waste Management Association, and actively serves on various regional and community civic organizations.

Ahmed F. Ghoniem



Ahmed F. Ghoniem is the Ronald C. Crane Professor of Mechanical Engineering, Director of the Center for Energy and Propulsion Research and the Reacting Gas Dynamics Laboratory, and Head of Energy Science and Engineering in ME. He received his B.Sc. and M.Sc. degrees from Cairo University, and his Ph.D. at the University of California, Berkeley. His research focuses on the development and application of computational methods for problems in fluid-thermal sciences, combustion and thermochemistry, and energy applications in the areas of CO_2 capture technologies such as gasification, oxy-combustion and chemical looping combustion, energy efficiency including high temperature and direct carbon fuel cells, clean combustion dynamics and control, fuel desulfurization, renewable fuels production, and the water-energy nexus. His laboratory conducts concurrent investigations of most of these processes using advanced optical diagnostics in bench-top and conceptual experiments. His research has led to significant advances in high-performance computing, multiscale approaches in reactive flow, and multiphysics analysis of multiphase flows; active control of noise and emissions in combustion; and energy systems' analysis with focus on low-carbon technologies, including IGCC, biomass conversion, pressurized oxy-combustion and novel CLC; thermochemistry of ion transport membrane reactors and fuel cells; and hybrid concentrated solar thermal systems. He has supervised 86 M.Sc and Ph.D. theses, and 23 postdoctoral students, published more than 270 refereed articles in leading journals and at conferences, and lectured extensively around the world. Ghoniem's scholarly work includes developing advanced graduate courses in energy conversion and combustion. He has consulted for several major aerospace, automotive, and energy companies as well as leading government research laboratories, and served on the board of high-performance computing centers and laboratories and several companies. He has won teaching and scholarly awards, is Fellow of ASME, and associate fellow of AIAA. He received the KAUST Investigator Award in 2008.

Karen Hussey

Dr. Karen Hussey is a Senior Lecturer at the Fenner School of Environment and Society, at the Australian National University, where she undertakes research in the field of environmental policy and economics, water resource management, the climate-energy-water nexus, and global environmental governance. She is Co-Chair of the ANU Water Initiative, Program Director of the ANU-USSC "AUSCEW" project on climate-energy-water links, and Board Member for the ANU-UNESCO Chair in Water Economics and Transboundary Water Governance. Dr Hussey also leads four externally funded projects exploring the governance challenges of sustainability.

Howard J. Herzog

Howard J. Herzog is a senior research engineer in the MIT Energy Initiative. He received his undergraduate and graduate education in chemical engineering at MIT. He has industrial experience with Eastman Kodak (1972-1974), Stone & Webster (1975-1978), Aspen Technology (1981-1986), and Spectra Physics (1986-1988). Since 1989, he has been on the MIT research staff, where he works on sponsored research involving energy and the environment, with an emphasis on greenhouse gas mitigation technologies. He was a Coordinating Lead Author for the IPCC Special Report on Carbon Dioxide Capture and Storage (released September 2005), a co-author on the MIT Future of Coal Study (released March 2007), and a U.S. delegate to the Carbon Sequestration Leadership Forum's Technical Group (June 2003 to September 2007). He was awarded the 2010 Greenman Award by the IEAGHG "in recognition of contributions made to the development of greenhouse gas control technologies."

David Kwangkook Jeong

David Kwangkook Jeong, Ph.D., P.E., has served as Assistant Professor of Mechanical Engineering for Arkansas State University (ASU), Jonesboro, since 2010; he completed his Ph.D. and postdoctoral research from ERC (Energy Research Center) at Lehigh University. He holds a Professional Engineer License as well as a Six Sigma Black Belt. He has performed federal (NSF/DOE) and industrial research projects, including NSF, DOE, and utility companies, etc., in the areas of existing and renewable power plant technologies as his research interests are in engineering design for full-scale fuel and energy systems using computational and experimental techniques with the expertise of heat/mass transfer, thermodynamics, fluid dynamics, combustion, reaction, separation, and phase change. He has 15 years of work experience in Korean and U.S. power industries with Korea Electric Power Corporation (KEPCO) and ERC. He is one of the founding faculty members of the Center for Efficient and Sustainable Use of Resources (CESUR) established by ASTA (Arkansas Science and Technology Authority), and has served as Associated Professor of Environmental Science (EVS) Program at ASU and Director of Research and Technical Services at JEPMECS.COM. He leads the Fluid and Thermal Energy Engineering Laboratory with graduate/undergraduate research assistants at ASU. Dr. Jeong has taught fluid and thermal curriculum—Engineering Thermodynamics-I/II, Design of Fluid/Thermal Energy Systems, Advanced Experimental Methods, Heat/Mass Transfer, and Fluid Mechanics—where he has facilitated interdisciplinary education and research. He has served as Principal Advisor of ASME and ASHRAE Student Chapters at ASU. He has been leading hundreds of students on technical tours, including at 850MW Coal-Fired Power Plant (Entergy), 580MW Dell Combined Cycle Power Plant (Wood Group Engineering, UK), 175MW Jonesboro Combined Cycle Power Plant (CWL), Nordex Wind Turbine Plant, and ASU Chiller Plant, etc. His résumé includes 39 technical publications, 41 technical presentations, and 6 patents.

Carey W. King

Dr. Carey W. King is Assistant Director of the Energy Institute at The University of Texas at Austin. In addition to his duties with the Energy Institute, Carey performs interdisciplinary research related to how energy systems interact within the economy and environment as well as how our policy and social systems can make decisions and trade-offs among these often-competing factors. Dr. King's goals center on rigorous interpretations of the past to determine the most probable future energy pathways. Much of his research focuses on the energy-water nexus, net energy analyis, energy economics, and systems and complexity descriptions of evolution of energy systems.

Dr. King is editing this book as Special Projects Chair of the ASME Interdisciplinary Council on the Energy-Water Nexus. He has served as Track Chair of the Energy-Water Nexus track of the ASME 2011 International Mechancial Engineering Congress and Exposition. Dr. King has both a B.S. with high honors and Ph.D. in Mechanical Engineering from the University of Texas at Austin. He has written extensively on the subject of the energy-water nexus, net energy systems analysis, electric grid operations including the integration of renewable energy, and carbon capture and sequestration. He has published technical articles in the academic journals *Environmental Science and Technology*, *Environmental Research Letters*, *Nature Geoscience*, *Energy Policy*, *Sustainability*, and *Ecology and Society*.

Olivier Le Galudec

Olivier Le Galudec graduated in Mechanical Engineering and Energetics from ENSEM in France in 1987, after which he joined French Naval Aviation as Air Traffic Controller Officer. In early 1989, he returned to the Lorraine region of France and started a Ph.D. on turbulent diffusivity within a nuclear reactor under a contract shared by CNRS (national research facility), CEA (comissariat à l'énergie atomique), and EDF (French power utility) while also

teaching mechanics and fluid mechanics at Nancy 1 University.
In early 1990, he joined Gec Alsthom (later ALSTOM) in Belfort as Thermodynamical Calculation Engineer within new Plants EPC business, and then shifted to Performance test activities 18 months later. In 1999, Le Galudec took over the management of the performance group in Belfort, then in 2001 the global performance group collated between Belfort (Fr) and Baden (CH) while still contributing to plant performance test campaigns: he cumulated experience over 140 guarantee verification campaigns on GT open cycles, Combined Cycles, add-ons, Steam turbines and conventional steam power plants. He now covers all technical guarantees for thermal performances and acoustics of new Plants within ALSTOM and contributes to several ASME Performance test codes.

Jean-Pierre Libert

As Vice-President of Advanced Technology with Evapco Inc., Jean-Pierre Libert oversees the research and development, product development, testing, rating, and modeling activities of field-erected cooling towers and air-cooled steam condensers. Libert holds an M.S. in Mechanical Engineering from Faculté Polytechnique de Mons, Belgium. He is an active member of the Cooling Technology Institute (CTI), a member in good standing of the American Society of Mechanical Engineers (ASME), and a member of several technical committees at CTI and ASME. Libert has authored a number of technical papers presented at CTI Conferences, EPRI Cooling Technology and Water Conservation Conferences, and ASME seminars. Since 1979, at a variety of assignments in Belgium, Mexico, and the U.S., Libert has acquired extensive cooling technology experience. He and his wife live in Frederick, MD.

Nadia Madden

Nadia Madden is a research associate at the Union of Concerned Scientists, where she conducts research for Energy and Water in a Warming World (EW3), a collaborative effort between the Union of Concerned Scientists (UCS) and a team of more than a dozen independent experts to build and synthesize policy-relevant research on the water demands of energy production in the context of climate variability and change. Madden has worked in the water and energy fields for over 10 years, with prior experience in business development at GreenFuel Technologies, project management at WaterHealth International, and river surveying for the Massachusetts Division of Fisheries and Wildlife. She administers local water policies on the Groton Conservation Commission, where she recently served as chair. Nadia holds a B.S. in Ocean and Atmospheric Physics from MIT, an M.S in Water Resources from the University of New Hampshire, and an M.S. in Energy and Resources from the University of California, Berkeley.

John S. Maulbetsch

Since 1999, Dr. Maulbetsch has been a private consultant to government and industry. Most of his work has been on water use and conservation in electric power production. He has published two major studies on alternative cooling systems for power plants for the California Energy Commission and the Electric Power Research Institute. Other studies have included the costs of retrofitting once-through cooled plants with closed-cycle cooling; the assessment of water conservation options for plants in arid regions; the effect of wind on air-cooled condenser performance; and the use of spray enhancement to augment the performance of air-cooled condensers on hot days. Prior to establishing his consulting practice, he was at the Electric Power Research Institute for 23 years. Before joining EPRI, Dr. Maulbetsch was the Director of the Energy Technology Center of Dynatech Corporation in Cambridge, MA, and before that on the faculty of the Massachusetts Institute of Technology. Dr. Maulbetsch received his S.B., S.M., and Ph.D. degrees from M.I.T. in 1960, 1962, and 1965, respectively.

Ariel Miara

Ariel Miara is a doctoral candidate and research associate at the CUNY Environmental CrossRoads Initiative, leading research focused on the interaction between energy systems, the environment, and policy. His work at CrossRoads is part of the development of a Regional Earth System

Model for the Northeastern U.S. Under the mentorship of Prof. Charles Vörösmarty, he created the Thermoelectric Power and Thermal Pollution Model (TP2M), which simulates the behavior of power plants according to electricity demand, physical conditions, and environmental regulation. Use of this model has led to key findings in the energy-water nexus field that feature in his publications and have been presented in major conferences. Miara is a Research Participant Program Scholar at the National Renewable Energy Laboratory's Strategic Energy Planning Analysis Center, continuing his work on energy-water issues as well as energy forecasting and modeling. He has an M.S. in Sustainability in the Urban Environment from City College New York and a First Class Honors B.Sc. in Mathematics and Physics from the University of London.

Eric Myers

Eric Myers is Manager of Water Lab and Emissions at CPS Energy. He has worked in different capacities for CPS Energy since 1994. He is responsible for power plant water and steam chemistry for fossil-fueled units at three locations. He has a B.S. in Electrical Engineering from the Air Force Academy and an M.S. in Electrical Engineering from the Air Force Institute of Technology.

Jamie Pittock

Dr. Pittock is a Senior Lecturer in the Fenner School of Environment and Society at The Australian National University and Director of International Programs for the UNESCO Chair in Water Economics and Transboundary Water Governance. He is also the Program Leader of the Australia and United States Climate, Energy and Water Nexus Project for the U.S. Studies Centre at the University of Sydney. Dr Pittock worked for non-government environmental organizations in Australia and internationally from 1989 to 2007, including as Director of WWF's Global Freshwater

Programme from 2001 to 2007. His research focuses on better governance of the interlinked issues of water management, energy and food supply, responding to climate change, and conserving biological diversity. Dr Pittock's recent research includes assessments of the impact of renewable energy and carbon sequestration policies on water resources and ecosystems, and the water-use implications of emission reduction measures proposed in Australia by applying a marginal cost of abatement prioritization. His work also considers the energy costs of water sector adaptation to climate change.

Abraham Francois du Preez

Dr. du Preez (Ph.D., Mechanical Engineering, University of Stellenbosch, South Africa) joined Eskom, the electric power utility in South Africa, in 1994, where he gained maintenance and operational experience on dry-cooling systems, including Air-Cooled Condensers. As responsible engineer in the position of Corporate Consultant he provides design, operational, and maintenance technical advisory and support service to power stations on condensers and cooling systems. His recent work includes specifications for the Air-Cooled Condensers for the 6x800MW Medupi and Kusile power stations, which are currently being constructed.

Johannes Pretorius

Dr. Pretorius studied at the University of Stellenbosch in South Africa and obtained his doctorate in Mechanical Engineering (focus on solar energy) in early 2007. Since 2007 he has been employed by Eskom in the Turbine Engineering department and he currently manages the Air-Cooled Condenser (ACC) Division as Chief Engineer. The ACC Division is responsible for the specification, design, and execution support for such systems on all newly built plants within Eskom, as well as supporting operating power stations which employ ACCs.

The main emphasis of his work has been on the specification and design evaluation of ACCs for Eskom's new-build dry-cooled power stations Medupi and Kusile, which are both under construction. Dr. Pretorius has also published and presented 17 technical articles on solar energy and dry-cooling in international journals or at international conferences. He is involved in Eskom's strategic research initiatives on dry-cooling.

Michael Rutberg

Michael Rutberg is a Senior Technologist at TIAX, a lab-based technology development company focused on advancing innovations in energy storage, transportation, building technologies, and advanced materials. His work at TIAX primarily involves development of sensor systems and HVAC/R technology; he is also a regular contributor to the "Emerging Technologies" column in *ASHRAE Journal*. Prior to TIAX, Michael earned his SM in Mechanical Engineering at MIT, where his research centered on water use at power plants. Part of the BP Energy Sustainability Challenge, the project sought to understand the relationships between water use, economic costs, carbon emissions, and other ecological impacts across a range of existing and emerging power plant technologies and configurations. At the 2012 MIT Energy Conference, he served as lead organizer for the panel "Water Limitations in Low-Carbon Electricity Generation." Also while at MIT, Michael authored DNJ, a powerful data exploration toolkit for Matlab. From 2005 to 2010, Michael worked at Honeybee Robotics on projects developing sensors and automated systems for industry, defense, and NASA. A notable example is the Sample Manipulation System, a key component of the robotic lab on board the Mars rover *Curiosity*. A member of ASME and IEEE, Michael holds a B.S. in Engineering from Swarthmore College.

John R. Saylor

Dr. Saylor received his Ph.D. from Yale University, his M.S. from the University of Minnesota, and his B.S. from the State University of New York, Buffalo. Dr. Saylor is currently a Professor of Mechanical Engineering at Clemson University, where he researches various aspects of air/water interfaces including evaporation, evaporation suppression, air/water transport, and the study of bubbles and drops.

Seth D. Sheldon

Seth D. Sheldon began studying energy and water systems in 2007 at Duke University, while earning a B.S. in Earth and Ocean Sciences. He graduated with a Ph.D. in Environmental Science from UMass Boston in June 2012, having developed a statistical model relating various environmental variables to Clean Water Act compliance by large, once-through thermoelectric facilities in Massachusetts. Prior to his position as senior scientist at Energy Points, he worked in various research capacities at East Central Florida Resource Conservation and Development, the Maine Coastal Islands National Wildlife Refuge, the West Virginia Department of Environmental Protection, the Urban Harbors Institute in Boston, and the Civil Society Institute in Newton, MA. Now at Energy Points, based in Boston, Seth leads development of the geospatial models that support the Energy Points resource analytics platform and calculation engine.

Ashlynn S. Stillwell

Ashlynn Stillwell is an Assistant Professor in the Department of Civil and Environmental Engineering at the University of Illinois at Urbana-Champaign. Stillwell completed a B.A. in Chemical Engineering at the University of Missouri in 2006, and then worked as a consulting engineer for Burns & McDonnell before attending graduate school at the University of Texas at Austin, earning dual master's degrees in Environmental & Water Resources Engineering and Public Affairs in 2010 and a Ph.D. in Civil Engineering in 2013. She was honored with the National Science Foundation Graduate Research Fellowship and the American Water Works Association's Academic Achievement Award for second-place master's thesis. Her research focuses on the energy-water nexus, and she has published numerous journal articles, conference papers, and reports on topics including the water impact of thermoelectric power generation, use of reclaimed water for power plant cooling, energy recovery from municipal wastewater treatment plants, and integrating wind power with brackish groundwater desalination.

Kim R. Stoker

Kim R. Stoker, REM, P.G., is the Director of Environmental Planning, Compliance & Sustainability at CPS Energy. She has been part of CPS Energy's Environmental program since 1989 and is currently responsible for air quality and water planning, material and waste management, sustainability, and land-use management issues. She and her staff provide permitting, compliance reporting, sustainability initiatives support, and environmental strategy services for CPS Energy. Stoker is a board member of the State of Texas Alliance for Recycling as well as a member of the Air & Waste Management Association and Texas Public Power Association; she also serves on various other industry and community committees. She has a B.S. in Geology from Stephen F. Austin State University and an M.S. in Hydrogeology from UT-San

Antonio. She is a Registered Environmental Manager and a Registered Professional Geologist in Texas.

Don Vandertulip

Don Vandertulip, P.E., BCEE, has 40 years of experience in recycled water pump, storage, and distribution systems; wastewater treatment, collection, and pumping; water supply planning, treatment, storage, and distribution; and program management. He recently served as technical director for the 2012 Update of EPA Guidelines for Water Reuse. One of his first water reuse projects was monitoring the El Paso Water Utilities pilot test for indirect potable reuse treatment and injection into the Hueco Bolson in 1979 as an Army captain at Wm. Beaumont AMC. Vandertulip is an active member of Water Environment Federation (WEF), American Water Works Association (AWWA), and WateReuse Association (WRA). He is immediate past-Chair, WEF Water Reuse Committee; member, WEF Municipal Wastewater Treatment Committee, recently served as author for two sections of MOP 8 update; participated with WEF and ASME joint workshop *Municipal Wastewater Reuse by Electric Utilities: Best Practices and Future Directions*; author of Chapter 4, AWWA M-24; editor/author of AWWA M-62; WRA-Texas Section Past-President, Co-Chair WateReuse Symposium (08, 09, 10), and Chair, Ad Hoc WRA Graywater Policy Committee; AWWA Water Reuse Committee and Reclaimed Water Standards Committee. He is also active in local and state organizations via the Water Environment Association of Texas (WEAT) and the Texas section of AWWA. Vandertulip represents both WRA and WEF on an International Association of Plumbing and Mechanical Officials (IAPMO) Green Technical Committee to resolve code requirements for on-site reclaimed water piping. He was recognized with the 2010 WRA President's Award for his outstanding leadership in chairing the Ad Hoc Graywater Committee. Additionally, he was selected as the Texas Society of Professional Engineers, Bexar Chapter 2004 Engineer of the Year. In 2013, he received the WEAT Alan H. Plummer Environmental Sustainability Award, which recognizes outstanding contributions in the field of environmental sustainability within the state of Texas.

Charles J. Vörösmarty

In addition to his dedication to mentoring CUNY students, Dr. Vörösmarty routinely provides scientific guidance to a variety of U.S. and international water consortia. He is a founding member and current Co-Chair of the Global Water System Project that represents the input of several hundred international scientists under the International Council for Science's Global Environmental Change Programs. He is spearheading efforts to develop global-scale indicators of water stress and is working with chief U.N. delegates who are negotiating the Rio+20 Sustainable Development Goals. His work on human-water interactions includes earth system modeling of the Northeastern U.S., development and analysis of databases depicting reservoir construction worldwide and how they generate downstream coastal zone risks, and global threats to human water security and aquatic biodiversity. He has served on a broad array of national panels, including the U.S. Arctic Research Commission (appointed by Presidents Bush and Obama), the NASA Earth Science Subcommittee, the National Research Council Committee on Hydrologic Science as Chair; he is also a member of the NRC Review Committee on the U.S. Global Change Research Program and the National Science Foundation's Arctic System Science Program Committee.

Michael E. Webber

Michael Webber is the Deputy Director of the Energy Institute, Josey Centennial Fellow in Energy Resources, Co-Director of the Clean Energy Incubator, and Associate Professor of Mechanical Engineering at UT Austin, where he teaches and conducts research on energy and environmental topics. He holds four patents, is on the board of advisers for *Scientific American,* and has authored more than 200 publications. His TV special "Energy at the Movies" was syndicated for national broadcast on PBS in 2013 and his capstone class "Energy Technology and Policy" is scheduled for distribution as a

MOOC (massive online open course) through a partnership with edX in Fall 2013. He has a B.A. and B.S. with High Honors from UT-Austin and an M.S. and Ph.D. (Mechanical Engineering) from Stanford. He has been an American Fellow of the German Marshall Fund, a White House Fellowship finalist, and an AT&T Industrial Ecology Fellow; UT has honored him for exceptional teaching.

1 Introduction

Carey W. King
The University of Texas at Austin

1.1 Purpose and Scope

Industry uses water throughout the energy supply chains. The ***purpose and scope*** of this book is to describe water for the cooling needs of thermoelectric, or steam cycle, power plants. The book focuses on engineering fundamentals along with environmental and economic contexts. Water is an excellent heat transfer medium, and it has historically been abundant and cheap. Thus, *thermoelectric*, or thermal or *steam-electric*, power plant cooling needs are usually served by withdrawing and consuming fresh and saline water. Thermal power plants do not have to use water for cooling, but if the desired quantities of water are available, then water-cooling systems are the most economic.

In many areas of the world, people are struggling to meet all demands for the supply of fresh surface water and groundwater. These water demands include those serving human activities as well as the demands of the natural environment. Human demands will likely continue to grow well into the 21st century, potentially putting more ecosystems at risk. Water demands for energy production and electric generation power plants are part of the total water demand. Because an inexpensive, abundant, high energy density, and relatively environmentally benign energy supply has been pivotal to grow modern and industrial economies (Smil, 2008), various constituencies have concerns about how water is used within the energy life cycle. This coupling of water needs for energy production describes one side of the ***energy-water nexus*** (the other being energy requirements for fresh water treatment and distribution).

While this book concentrates on power plants that need cooling of their steam cycles, there are several methods to generate electricity using technologies that are not based upon steam cycles: Brayton cycles (simple cycle using gas turbines), hydropower systems, solar photovoltaics, wind power, and concentrating solar power based upon Stirling engines. While these power generating technologies are important for current and future energy supplies, the scope of this book does not comprehensively include integrated water and/or energy planning that can consider the trade-offs among all energy supplies and all water demands. Local and regional planning processes can consider a broad mix of energy supplies and technologies that weigh trade-offs between energy and water resources. One significant consideration is the choice to use electric generation technologies that do not need cooling of steam cycles.

This book contributes important information to aid a broader discussion of integrated water and energy management by providing background, references, and context for water and energy stakeholders specifically on the topic of water for cooling thermal power plants. It serves as a source of information to:

- power plant owner/operators,
- water resource managers,
- energy and environmental regulators, and
- non-governmental organizations.

From power plant owners wanting to know the trade-offs in environmental impact and economics of cooling towers to water utilities that might want to deliver wastewater for reuse for power plant cooling, this book provides an array of regulatory and technical discussions to meet the needs of a broad audience. This book will not teach a practicing cooling tower design engineer how to build a better cooling tower, but it will teach that person some aspects that environmental and regulatory organizations consider when evaluating the impact of cooling water usage. Conversely, this book will not teach environmental organizations much more than they already know about the impact of industrial water usage on ecosystems, but it will explain to them some engineering fundamentals and terminology that will enable them to communicate better with the electric power industry.

This book is organized in the following manner:

Chapter 1 - Introduction: This chapter provides definitions, background, trends, and motivation for understanding trade-offs associated with water used for cooling. Definitions are important to clarify what any one person means by water "use." Chapter 1 defines several words as used in this book to describe water flows associated with power plant cooling. Some of the distinctions in definition are best described via diagrams, as done in this chapter. In certain discussions, such as in accounting for water consumption and the environmental impact of power plant water use, diagrams can help focus discussion among disparate stakeholders. Some original diagrams are used along with those of the Energy Information Administration of the U.S. Department of Energy, an agency that collects and distributes data on U.S. and worldwide energy.

Chapter 1 also shows a time series for power plant cooling technologies installed in the United States to give perspective on the long-term shift in cooling technology installations from once-through to wet-cooling towers, and more recently to dry-cooling systems that do not consume water for cooling. These cooling system installation trends parallel changes in the installed types of prime movers. Relevant for the energy-water nexus is the relatively recent prominence of non-steam-based prime movers, such as combustion turbines and wind turbines, which don't need water for steam cooling. Both the trends of prime movers and cooling technologies provide additional context to discussions surrounding water needs for new and existing power plants as more areas of the world have increasing populations and competing water needs.

Chapter 1 concludes with a summary of typical values for water withdrawal and consumption for various combinations of prime movers and cooling technologies. The calculations and mathematical models of Chapter 3 provide the background knowledge to understand this summary information.

Chapter 2 – The Context of Thermal Power Plant Water Usage: This chapter provides a fuller discussion of how to consider thermoelectric power plant water needs in the context of water basins and environmental impact. Section 2.1 discusses some broader whole system context of power plants within the environment and economy. Integrated water resources management is one process by which stakeholders engage to weigh the trade-offs of using water for various purposes. It is important to remember that water demand for thermal power plant cooling must be considered within the perspective of a specific water basin and economic situation as related to energy and water security, air and water quality, impact from climate change as well as greenhouse gas emissions, and benefits to and impact on biodiversity

Section 2.2 describes the environmental impact and regulations related to power plant water withdrawals and discharges. Many of these regulations take years if not over a decade from conceptualization to final ruling. The authors provide a nice timeline of important U.S. environmental regulations impacting water use by power plants. Section 2.3 presents an example analysis of how thermal discharges from upstream power plants can affect downstream power plants that reside on the same river. In this sense the authors invite us to think about the coupled interactions of multiple water withdrawals and discharges, for all purposes, on any particular water body. Section 2.4, authored by the Energy Information Administration (EIA), describes the water data collection forms as managed by the EIA of the U.S. Department of Energy. Thus environmental managers can understand how to work with the EIA, and possibly other governmental offices, on collecting accurate and relevant information.

Chapter 3 – Engineering and Physical Modeling of Power Plant Cooling Systems: Chapter 3 focuses on mathematical engineering analyses and models that estimate the water consumption for wet, or water-based, power plant cooling. Section 3.1 provides an engineering description of the heat and water balances that govern thermoelectric power plant cooling performance and design. The major categories of cooling systems are described: once-through, wet-cooling towers, use of cooling ponds, dry cooling, and hybrid wet-dry systems. Section 0 presents a system-level "generic" parametric model that describes thermal power plant water consumption and withdrawal. The simplified model and informative charts provide a nice summary of how water consumption and withdrawal are affected by the major system and climatic parameters. Section 3.3 introduces some specific water consumption information for natural gas combined cycle (NGCC) power plants. This is important because a large quantity of NGCC power plants have been installed across the world in the last couple of decades, and they need less water for cooling than traditional steam-cycled power plants. Section 3.4 describes methods to extract water from flue gas of thermal power plants that combust fuels (fossil or biomass). This is particularly relevant for combined heat and power systems, and flue gas water condensation could be a valuable supplemental water supply for power plant cooling.

Section 3.5 describes cooling needs specific to nuclear power plants, including issues related to handling of spent fuel and cooling during shutdown and emergencies. Section 3.6 discusses the United States Geological Survey (USGS) method for estimating freshwater consumption of thermoelectric power plants as part of its quinquennial

Water Use Survey. This USGS-authored section includes a survey of methods for estimating forced evaporation from discharged water from systems designed as once-through or recirculating with cooling ponds. This is an important contribution to this book because the USGS Water Use Survey is a reputable water-use reference for researchers and policymakers in the United States. Section 3.7 describes evaporation effects from cooling ponds along with concepts for suppressing evaporation for water conservation. Section 3.8 discusses some specific water quality issues related to handling and treating reclaimed water for use in power plant cooling systems. The author of this final section of Chapter 3 has significant experience in water reuse for power plants and other users, so the section provides a valuable summary to spur discussion with wastewater facilities.

Chapter 4 – Economic Considerations and Drivers: Chapter 4 focuses on the economics of power plant cooling and the trade-off of using water or air as the main cooling fluid. Sections 4.1 to 4.4 provide an analysis of the annualized cost, power generation, and water consumption for different types of cooling systems (wet-cooling tower, direct dry, indirect dry, and a hybrid wet-dry system). The analysis is done for coal, nuclear, and natural gas combined cycle plants for different climatic regions to show how local conditions affect the outcome. Any given cooling technology does not operate with the same efficiency in a hot and humid versus a cool and dry climate. Section 4.5 discusses a procedure for estimating costs of retrofitting once-through cooling systems to cooling towers, including a short description of a couple of past retrofits. Section 4.6 concludes the chapter with an additional perspective on how to value different cooling systems per the operational (profit) risk to a power plant. Instead of viewing dry-cooling systems as simply more costly than wet-cooling systems, perhaps they act as insurance investment against drought conditions.

Chapter 5 – Cooling System Case Studies: The book ends with a chapter of examples of power plants across the world that, due to various drivers, demonstrate various alternative cooling systems and/or water supplies for cooling systems. These case studies are useful to think of how different cooling water sources and technologies fit within the context of each specific situation, not only in the United States, but also across the world.

Section 5.1 describes various choices for dry cooling for the direct needs of protecting wildlife—North Africa (dry cooling for wildlife protection), Argentina (dry cooling to avoid disturbing wildlife to maintain tourism)—and aesthetic and safety concerns: United Kingdom (dry cooling to avoid visible plumes). Several case studies describe the use of dry cooling: Queensland, Australia (Section 5.2), and South Africa (Section 5.5) dry-cooling systems, all for coal-fired power, operate largely in response to concerns over local water scarcity. The Queensland power plant is perhaps the newest and most efficient coal-fired plant that uses dry cooling. The South African state-owned electric utility Eskom operates one of the largest fleets of dry-cooled power plants in the world. Section 5.3 provides a case study not of cooling technologies, but of how Australian water markets can help facilitate appropriate regulatory and institutional frameworks that provide opportunities for electric power generators and other water users in the energy sector to flexibly manage risks and minimize costs through the efficient pricing of water inputs. Section 5.4 provides a very complete and informative discussion of the use of municipal wastewater integrated with recirculating cooling on cooling lakes in San Antonio, TX. Finally, Section 5.6 closes the book with a description of Spain's climate and water for cooling its nuclear power plants.

1.2 Background on Water for Power Plant Cooling

1.2.1 Water "Use" Definitions

The quantification of how water is "used" is an important concept for all activities related to natural water supplies as well as municipal, commercial, or other government-supplied treated water. Because the word "use" is not specific enough to understand how power plants interact with water in our environment, it is also important to distinguish among different definitions of water "use." For the purposes of this book, the term "water use" is used only in the general sense, and quantifications of water flows and environmental impact are more specifically defined by the definitions and diagrams listed in this section.

Unfortunately, when discussing different types of water "use," it becomes difficult not to define a term using the term itself. This difficulty is addressed by engineering water flow diagrams that improve the ability to define and discuss the same term from multiple perspectives. For additional information and water flow diagrams that complement the information in this chapter, see USGS Water Use Surveys (Kenny et al., 2009; Solley et al., 1998) and EIA form 923 (EIA, 2013a, EIA, 2013b).

The “water use” definitions used in this book are:

Consumption or consumptive use: That part of water withdrawn and/or diverted that is not returned (discharged) because of evaporation, transpiration (via crops), or incorporation into products. By definition, consumption is less than or equal to withdrawal. Common power plant processes causing evaporative consumption are cooling towers, forced evaporation, turbine inlet coolers (precooling air entering compressors of simple cycle turbines), and flash steam losses.

Discharge (or discharge flow): The quantity of water that is returned to a surface- or groundwater source after release from the point of use and thus becomes available for further use. By definition discharge is less than or equal to withdrawal. The specific point of discharge is not necessarily the same as the point of withdrawal. In the context of power plant cooling ponds, discharge should not include water returned to the cooling pond for later reuse at the power plant.

Diversion (or diverted flow): The quantity of water removed from a watercourse without immediate beneficial use. An example is diversion for the purpose of filling a cooling pond or reservoir prior to withdrawal into a thermoelectric cooling system.

Forced evaporation: That additional water evaporated from surface water bodies as a result of the additional heat added within discharged power plant cooling water.

Natural evaporation: Evaporation from surface water bodies that occurs due to the natural ambient conditions (temperature, humidity, wind speed, etc.) of the local climate.

Return flow: Same as discharge.

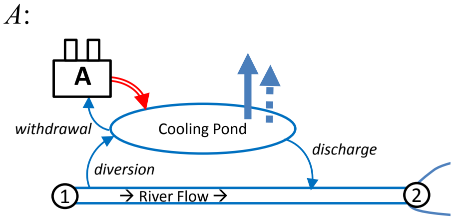
Withdrawal: The quantity of water removed from a water body for beneficial use. Beneficial uses for thermoelectric power plants include cooling water, boiler makeup water, ash sluicing, and dust suppression.

1.2.2 Configurations that Characterize Water "Use" of Power Plant Cooling Systems

One important point for understanding the context of power plant water use is not only the quantity of water associated with the above definitions, but also the *specific location* that corresponds to a quantified water use. Figure 1-1 provides a conceptual schematic for multiple configurations and contexts for thermoelectric power plants within a river basin. Figure 1-1 focuses on the use of surface water, although groundwater extraction can also serve power plant water needs, and it is always important to understand local and regional linkages between surface water and groundwater. In Figure 1-1, water in a river flows from left to right, and from point 1 to point 2 to point 3 before it enters a coastal environment. The power plant cooling configurations represented in Figure 1-1 refer heavily to the terminology and descriptors as used by the U.S. EIA forms 860 and 923 (see Section 2.4). EIA form 923 logs information (e.g., power generation, fuel consumption, etc.) about the operation of electric generators, including quantities describing cooling water usage. The schematic from the EIA form 923 instructions is shown in Figure 1-2 (see Section 2.4 for discussion of EIA data collection). EIA form 860 records information about cooling system type or design.

The descriptions of the configurations in Figure 1-1 use terminology of the EIA, and the definitions from the previous section, to help power plant environmental managers determine what type of cooling system to select on the EIA forms. The choice of cooling system type to select is not always obvious. Included in the description of the configurations of Figure 1-1 are the two-letter abbreviations (e.g., OF, RC, etc.) for EIA cooling system types that best represent the configurations A-K. The discussions of these configurations focus on layout and relative consumption of water for cooling. Here, I also mention which configurations involve significant heated water discharge into aquatic environments, but the reader should read Chapter 0 for a full discussion of thermal and other water quality impacts.

A:



This power plant configuration is most accurately described as a *recirculating system with a cooling pond (RC)* and "cooling pond or canal" of Figure 1-2. In this case, the cooling pond is sometimes referred to as "off-channel" of the creek or river that supplies the water. The power plant can divert water as needed from the river to fill the cooling pond, and this need not occur on a continuous basis. From the cooling pond, the power plant withdraws cool water and returns heated water to the cooling pond, but not to the river. Thus, the cooling pond will exist at an elevated temperature relative to if there were no power plant because the cooling pond is a finite heat sink. Water is consumed within the cooling system due to forced evaporation from the cooling pond. Natural evaporation from the cooling pond also occurs, and if the power plant owner is the sole owner and user of the cooling pond, it is conceptually accurate to allocate the natural evaporation to the operational life cycle of the power plant. If the power plant owner is not the sole user of the cooling pond, then it is conceptually accurate to allocate some natural evaporation to other needs such as recreation, municipal supply, or agriculture if those needs benefit from the water storage. At the discretion of the power plant and/or cooling pond operator, water can be discharged from the cooling pond to the river. In this configuration, it is possible that there could be no flow in the river, but that due to diverted water for storage in the cooling pond, the power plant could continue to operate using water from the cooling pond. All other considerations equal, due to forced and natural evaporation, over time configuration A will cause less total water to flow in the river through point 2, just downstream of the diversion point, versus point 1 (see Figure 1-1). At any given time when water is not being diverted into the cooling pond, the same water flow rate would occur at point 2 as at point 1. Because the power plant does not normally or directly discharge water to the river, the power plant would not normally increase the river water temperature at point 2 relative to point 1.

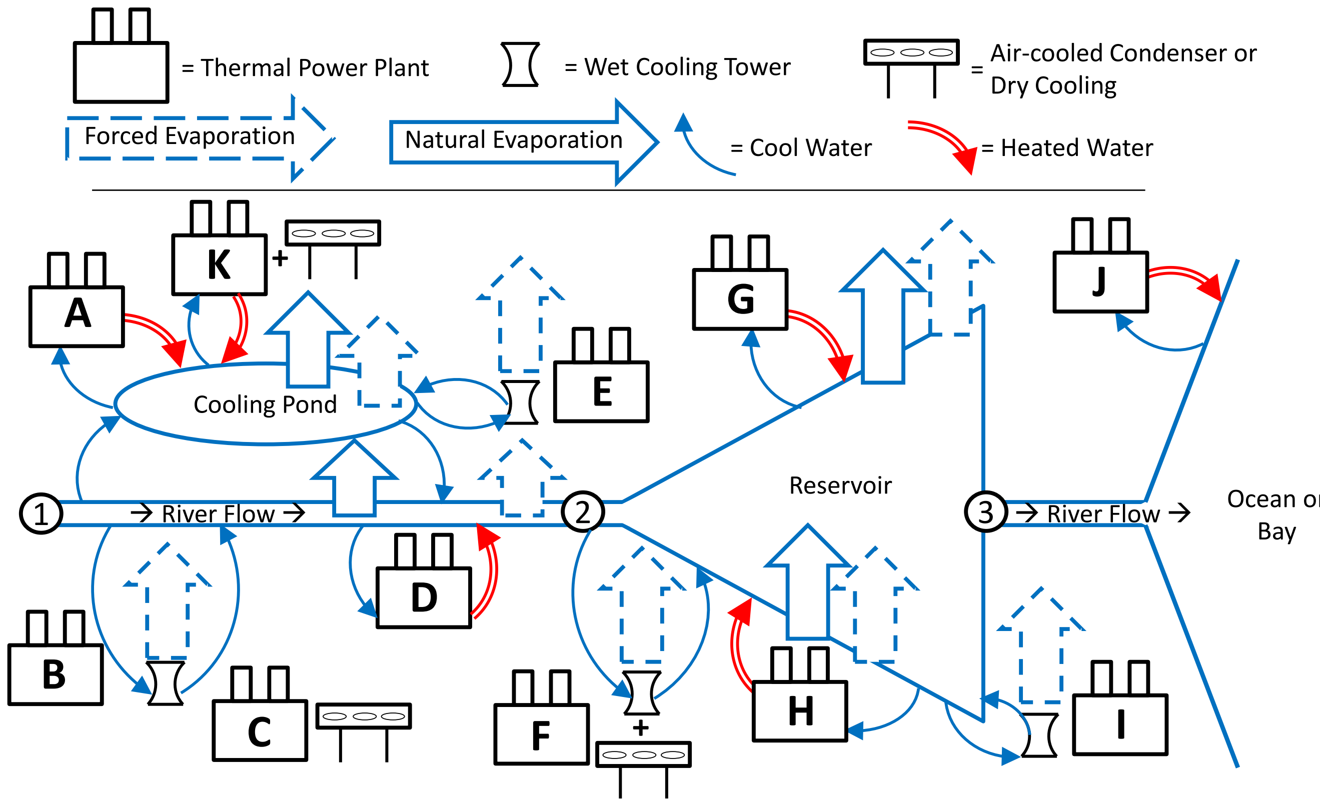


Figure 1-1. There are many contexts in which to view the water use (withdrawal, consumption, diversion, and discharge) of thermoelectric power plants.

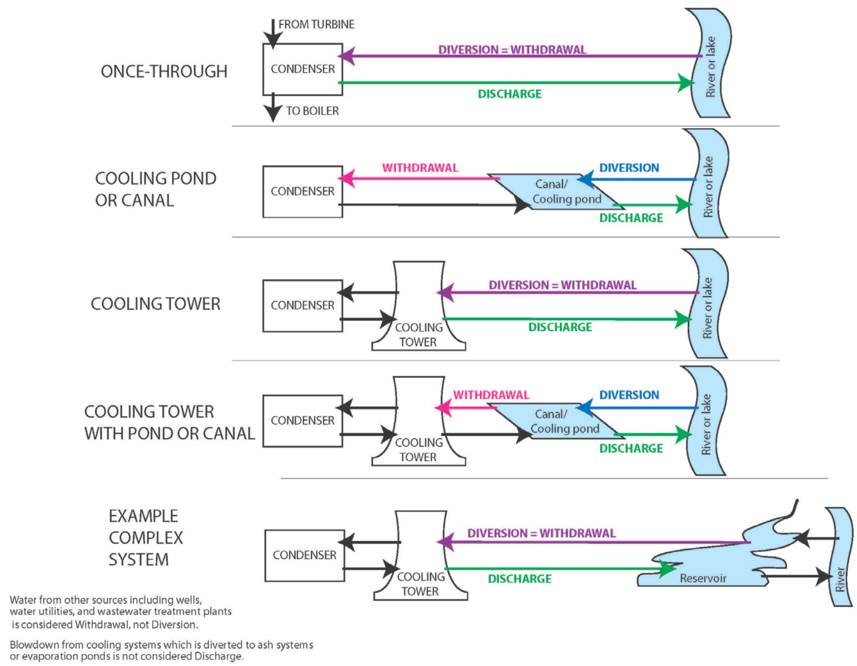
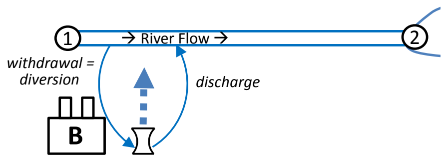


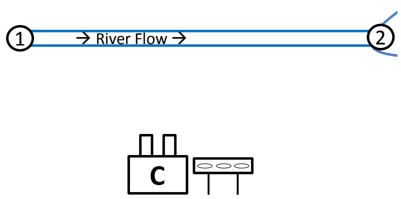
Figure 1-2. The schematic defining different power plant water uses for EIA form 923. Figure 1-1 should be viewed as a more granular version of the same schematics (EIA, 2013a). For the "example complex system," the flow from the river to reservoir can be considered diversion, and the flow from the reservoir to the river can be considered discharge. Because there is no 1:1 correspondence between cooling system and an electric generation unit, it is not possible to summarize how much power plant capacity corresponds to the cooling types of this figure.

B:



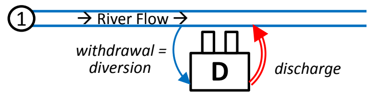
This power plant cooling configuration is, in Figure 1-2, most accurately described as *recirculating cooling tower, fresh water, on a river (RI, RF, or RN)*, and "cooling tower". Water is withdrawn from the river and input into the cooling tower, and then most of the water is evaporated. For most of the time during normal operation, the river water temperature at point 2, immediately downstream, would not be appreciably warmer relative to point 1. Some water (e.g., cooling tower blowdown) can be discharged into the river as allowed by permits and regulation, and if this blowdown is taken from the cooling tower water return, then this heated water could conceivably increase the water temperature immediately downstream of the power plant near the discharge point. There is often some quantity of raw water storage for the power plant, but in general enough water must be flowing in the river to enable the cooling system to function in continuous reliable operation.

C:



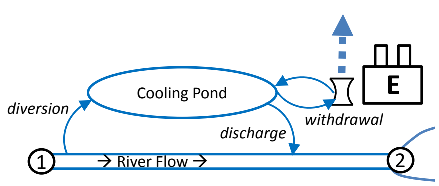
This power plant cooling configuration is most accurately described as *dry cooling (DC)*. Practically any of the options of Figure 1-2 indicating a cooling tower could describe dry cooling because the cooling tower could be a wet or dry (including air-cooled condenser) system. No water is withdrawn from the river, cooling pond, or reservoir for steam cycle cooling needs, however there can be water use for other plant processes such air emissions control equipment. Thus, the overall power plant consumes and withdraws less water than wet cooling configurations because it does not need water for cooling the steam cycle.

D:



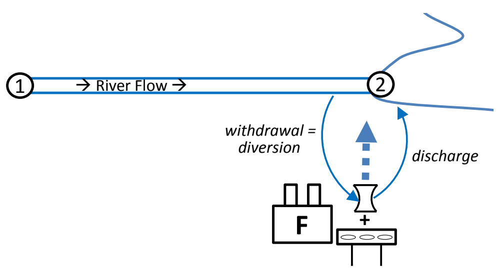
This power plant configuration is, in Figure 1-2, most accurately described as *once-through, fresh water, on a river (OC, OF),* and "once-through". Here, cool water is withdrawn from the river and heated water is discharged back into it. The temperature of the river water at point 2 near the point of discharge will be appreciably warmer than point 1 upstream of the power plant. A *thermal plume* exists downstream from the discharge point, and the shape of this thermal plume is dictated by the local geography (river shape) and climate (river flow rates, air temperature, humidity, etc.). Conditions specific to each power plant, as well as some arbitrary definitions of temperature differences that can define a thermal plume, make it difficult to state any typical size of a thermal plume. There is no water storage for the power plant, and enough water (generally one to two orders of magnitude higher flow rates than for power plant cooling configuration B) must be flowing in the river to enable the cooling system to function.

E:



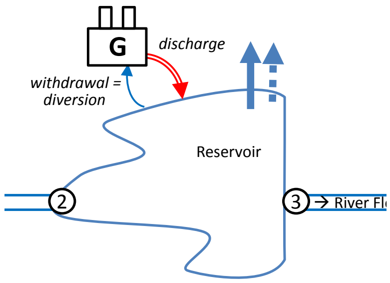
This power plant configuration is, in Figure 1-2, most accurately described as *recirculating cooling tower, fresh water, on a pond (RI, RF, or RN),* and "cooling tower with pond or canal". The power plant can divert water as needed from the river to fill the cooling pond, and this need not occur on a continuous basis. From the cooling pond, the power plant withdraws cool water and possibly returns some water to the cooling pond, but does not directly discharge water to the river. Water is consumed within the cooling system due to forced evaporation in the wet-cooling tower. Natural evaporation from the cooling pond also occurs, and if the power plant owner is the sole owner and user of the cooling pond, it is conceptually possible to allocate natural evaporation to the operational life cycle of the power plant. If the power plant owner is not the sole user of the cooling pond, then it is conceptually accurate to allocate some natural evaporation to other needs such as recreation, municipal supply, or agriculture if those needs benefit from the water storage. In this configuration E, there is no appreciable forced evaporation in the cooling pond itself because little to no heated water is discharged into it, but the vast majority of the water withdrawn in the cooling pond is evaporated from the cooling tower. If power plants A and E are equal except for the cooling system, there will be more total evaporation (water consumption) for configuration E versus configuration A. Configuration A evaporates less total water because the cooling pond can dissipate heat by means other than water (latent heat) evaporation: radiation to the sky, conduction into the ground, water infiltration, and convection to air flowing over the pond. At the discretion of the power plant and/or cooling pond operator, water can be discharged from the cooling pond to the river. In this configuration, it is possible that there could be no flow in the river, but that due to diverted water for storage in the cooling pond, the power plant could continue to operate using water from the cooling pond. Due to water diversion from the river to the cooling pond to replace water lost to cooling tower evaporation and natural pond evaporation, over time, less total water will flow in the river through point 2 versus point 1. At any given time when water is not being diverted into the cooling pond, the same water flow rate would occur at point 2 as at point 1. The river water temperature at point 2 would not be appreciably warmer than point 1.

F:



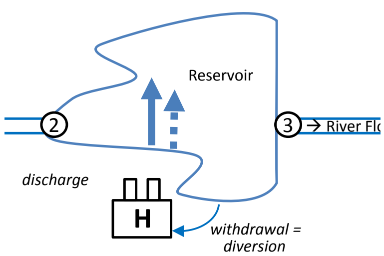
This power plant configuration is, in Figure 1-2, most accurately described as *hybrid recirculating with forced or induced draft cooling tower(s) with dry cooling (HRF, HRI),* and possibly any of "cooling tower," "cooling tower with pond or canal," or "example complex system". This configuration has the same water impact and ramifications as configuration B, but with less total water withdrawal and consumption due to the inclusion of some dry cooling.

G:



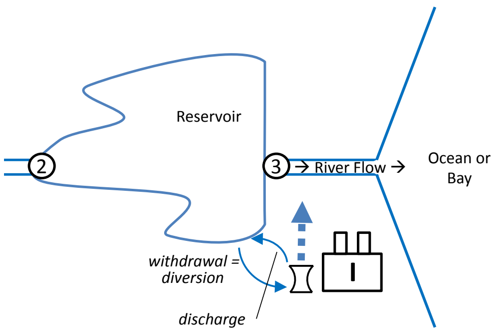
This power plant configuration is, in Figure 1-2, most accurately described as *once-through on a freshwater lake/reservoir (OF, OC),* and "once-through". In this case, the reservoir is sometimes referred to as "on-channel" of the creek or river. Here, cool water is withdrawn from the reservoir and heated water is discharged back to the reservoir. In a shape emanating from the cooling water discharge point, a thermal plume will define a volume of water that is appreciably warmer. For a constant water flow at point 2 and point 3, and assuming no rainfall onto the reservoir, theoretically the level of the reservoir would drop over time. This theoretical drop in reservoir level is due to both natural and forced evaporation from the reservoir. In practical situations, local climate conditions (temperature, precipitation) and reservoir management for all needs (irrigation, municipal, environment, etc.) dictate the level of a reservoir. In addition, the difference between configuration G and configuration A is that there is no separate water diversion into the storage reservoir (or pond) because the reservoir is in line with the river itself. With further analysis, it would be possible to describe how cooling configuration G is more or less resilient to drought than configurations A or H.

H:



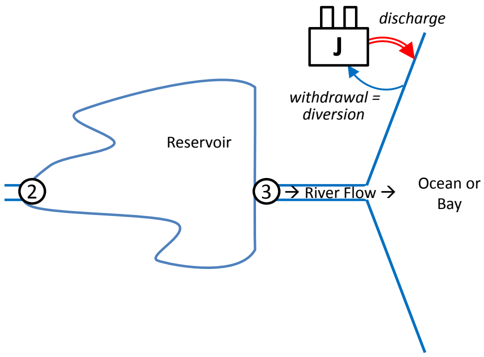
This power plant configuration is, in Figure 1-2, most accurately described as *recirculating system with a cooling pond (RC),* and "cooling pond or canal" but could be interpreted as "once-through." The only conceptual difference between configuration H and configuration G is that the warm water discharge of configuration G occurs downstream from the intake but for configuration H the warm water discharge occurs upstream from the intake. Thus, it is conceptually accurate to consider configuration H as possibly "recirculating" the same water molecule by discharging upstream, and having the water molecule flow back downstream to the intake again. Several reservoirs used for cooling have upstream discharge. Just as in configuration G, the reservoir loses water due to both natural and forced evaporation. In addition, the difference between configuration H and configuration A is that there is no separate water diversion into the storage reservoir (or pond) because the reservoir is in line with the river itself. Without further analysis, it is not possible to describe how cooling configuration H is more or less resilient to drought than configurations A or G.

I:



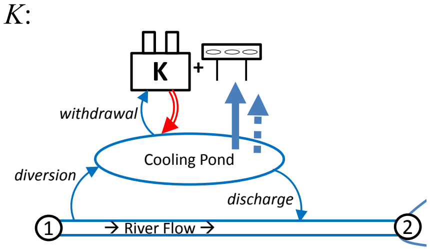
This power plant configuration is, in Figure 1-2, most accurately described as *recirculating cooling tower, fresh water, on a reservoir (RI, RF, or RN),* and "cooling tower" or the general "example complex system", as both conceptually include the concept of withdrawing water from a lake for input into the cooling tower. The description of this configuration is a combination of configurations E and H. There is little to no substantial quantity of warm water discharged into the reservoir as the power plant heat is dissipated via evaporation of the water in the cooling tower. Just as in configuration B, some water (e.g., cooling tower blowdown) can be discharged, this time into the reservoir, as allowed by permits and regulation. If this blowdown is taken from the cooling tower water return, then this heated water could conceivably increase the water temperature, causing a thermal plume originating at the discharge point. For the same reasons that cooling tower configuration E consumes more water (via evaporation and for a given amount of power generation) than configuration A with no cooling tower, cooling configuration I consumes more than either configurations G or H.

J:



This power plant configuration is, in Figure 1-2, most accurately described as *once-through, saline (OS),* and "once-through". In this case, cool water is withdrawn from the ocean/bay/canal and warm water is discharged back into the saline water body. There is forced evaporation of fresh water (from the saline water body), but this evaporation is miniscule compared to the natural evaporation of the ocean. Relative to the other cooling configurations, this configuration conserves fresh water because it does not use fresh water for cooling. However, use of once-through saline systems can be limited by geography (access to coastal waters) as well as social and environmental protection considerations (see Chapter 5 case studies). The intake of seawater also poses engineering challenges related to corrosion and attachment and intake of barnacles and mussels. The use of seawater for cooling, however, is established engineering practice.

K:



This power plant configuration is, in Figure 1-2, most accurately described as *hybrid recirculating cooling pond(s) or canal(s) with dry cooling (HRC),* and likely "cooling tower with pond or canal" or possibly "example complex system". This configuration has the same water impacts and ramifications as configuration A, but with less total water withdrawal and consumption due to the inclusion of some dry cooling.

1.2.3 Trends in Power Plant and Cooling System Installations (United States)

Since the dawn of the Industrial Revolution we have developed and installed many types of electric generating power plants. As new fuels, technologies, regulations, and constraints emerged, they influenced the type of power plant that was most viable to install during given time periods. Many of the first power plants were hydropower facilities that directly used water to flow through turbines and generate electricity for early 19th century industry (see Figure 1-3).

In the United States after World War II, steam cycle–based power plants came to dominate the electricity landscape, accounting for over 500,000 MW of installed capacity from 1950 to 1990. These thermoelectric plants, driven by the combustion of fossil fuels and nuclear fission, are the dominant means for electricity generation accounting for half of today's installed U.S. generating capacity (EIA, 2011). In Figure 1-3, the steam-based power plants are represented by the symbols ST (steam turbine), CA (steam part of combined cycle power plants), and CS[1] (single shaft combined cycle). The second-most dominant type of prime mover is the combustion turbine (CT, GT), gaining more prominence in the late 1990s after many U.S. electric regions were deregulated and took advantage of the situation when modern combined cycle power plant designs came into mainstream use with relatively low natural gas prices. Also, there was an increase in wind turbine installations after 2000. Because wind power consumes no water during operation, and natural gas combined cycle systems have low cooling needs compared to pure steam cycles (see Chapter 3), one can deduce that the power plant installations of the last two decades have a lesser cooling demand per unit of energy output (e.g., cooling per kWh) than those of the four previous decades. However, existing, or brownfield, power plant locations will continue to operate and potentially have new or rebuilt thermoelectric power plants on the same sites that will continue to require cooling, primarily by withdrawing and consuming water. This historical background provides some additional context for the discussions in this book.

[1] CS prime movers are both part combustion turbine and part steam turbine, but for simplicity, we lump CS into the "steam-cycle" category.

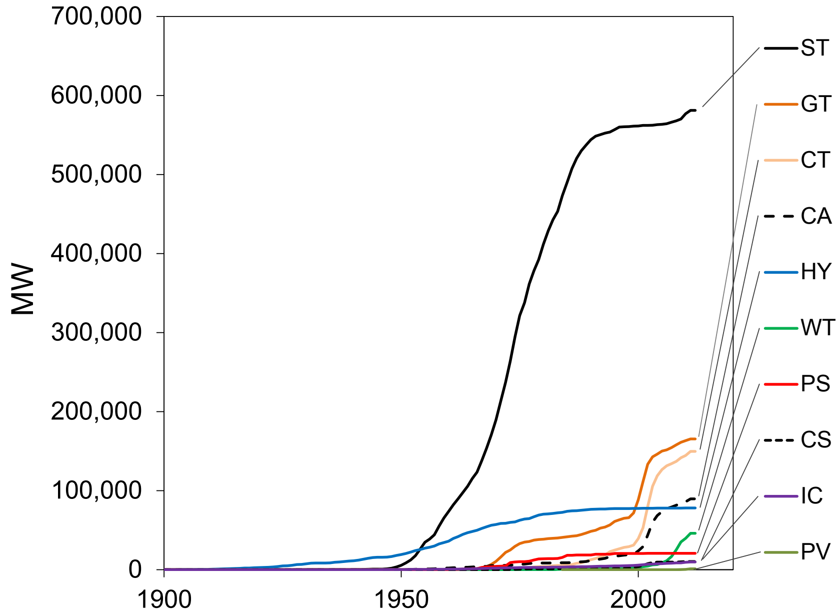


Figure 1-3. The cumulative installation of U.S. power plants (through 2011) that use a given type of prime mover has changed over the years (ST = steam turbine, CA = steam turbine of combined cycle, CT = combustion turbine of combined cycle, CS = single shaft combined cycle, HY = hydropower turbine, GT = single cycle combustion turbine, IC = internal combustion engine, PS = pumped storage, PV = photovoltaic, WT = wind turbine). [source: EIA form 860, all generation units listed as "existing" as of 2011].

To provide additional context for thermoelectric cooling needs and technologies, it is informative to understand how cooling system trends have changed over time. Figure 1-4 shows U.S. data for the quantity of three major categories of thermoelectric cooling system installations versus the installed capacity of prime movers that operate with steam cycles, and thus require cooling. The data come from the Energy Information Administration form 860; it is important to note that there is no 1:1 correlation with any given prime mover and a cooling system at a power plant (see Section 2.4). One power plant can have multiple types of cooling systems that integrate with multiple prime movers fed with multiple fuels. Thus, there is no summary of the percentage of facilities or generation units that employ a combination of fuel and cooling technology type as specified in Figure 1-1 or Figure 1-2. Figure 1-4 does not associate specific cooling system types with the installed prime movers (i.e., it plots each cooling system type category versus all ST, CA, and CS prime movers).

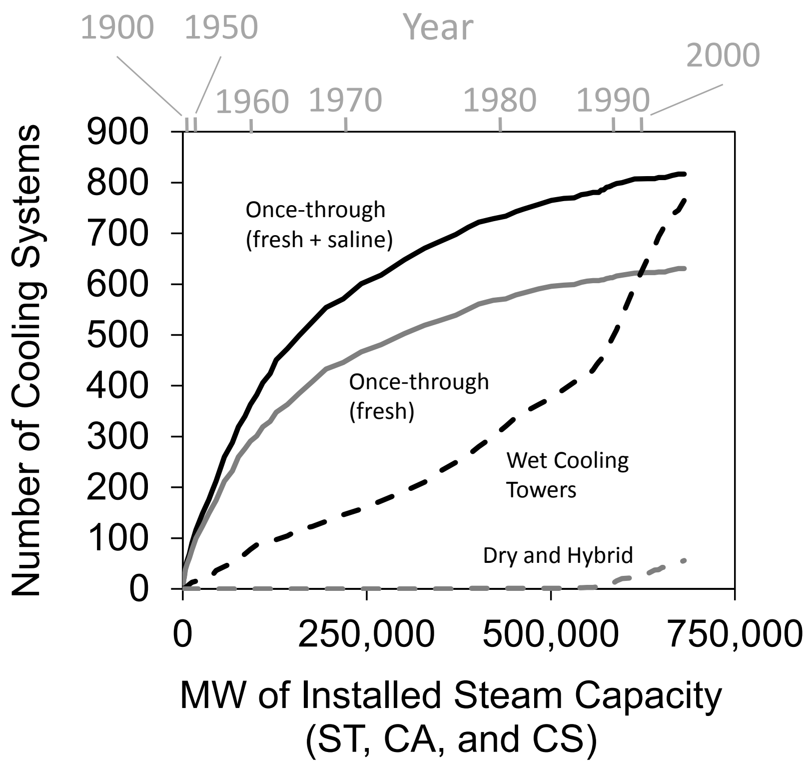


Figure 1-4. The number of once-through type cooling systems in the United States shows a diminishing installation rate as a function of the total installation of power plant capacity that uses steam cycles and necessitates cooling via steam condensers. ST = steam turbine, CA = steam turbine of combined cycle, CS = single shaft combined cycle (some capacity is for combustion turbine). "*Once-through (fresh + saline)*": OF = once through, fresh water, OC = once through with cooling ponds or canals, RC = recirculating with cooling ponds or canals, and OS = once-through, saline water. "*Once-through (fresh)*": OC, OF, and RC. "*Wet-Cooling Towers*": RF = recirculating with forced draft cooling tower, RI = recirculating with induced draft cooling tower, and RN = recirculating with natural draft cooling tower. "*Dry and Hybrid*": DC = Dry- (air-) cooling system, HRC = Hybrid – recirculating cooling pond(s) or canal(s) with dry cooling, HRF = Hybrid – recirculating with forced draft cooling tower(s) with dry cooling, and HRI = Hybrid – recirculating with induced draft cooling tower(s) with dry cooling [source: EIA form 860, all generation and cooling units listed as existing and operating (OP) as of 2011].

Once-through designs were the most common for the first 250,000 MW of steam capacity installed by 1972, but wet-cooling towers have been the dominant cooling design during the last 250,000 MW (since 1980). Dry and hybrid systems have been installed since the 1990s, mostly in arid areas such as the Western U.S. with over 50 systems in operation by 2010 (in 2011, 52 of the 56 dry and hybrid cooling systems in the U.S. were dry cooling only). For various reasons related to competing water demands for all water uses, after 1970 once-through cooling systems were installed much less frequently as compared to wet-cooling towers. Perhaps not coincidentally, the Clean Water Act was passed in 1972. It is speculative to assign quantifiable relevance for specific drivers of the shift in cooling technology, but the regulations arising from the environmental movement of the 1960s and 1970s played a significant role. During the first decade of the 21st century, dry and hybrid cooling systems have been installed more often than once-through systems. Chapter 2 discusses U.S. Environmental Protection Agency regulations related to power plant cooling systems, including recent revisions that practically prevent the installation of new once-through designs [e.g., Clean Water Act, Section 316(a) and 316(b)].

1.2.4 Measuring and Estimating Thermal Power Plant Cooling Water Consumption and Withdrawal

Cooling system design largely dictates the rate (gallons/MWh), quantity of water withdrawal, and consumption of the thermal power plant. The power plant efficiency, or *heat rate* (energy input per kWh of generation), affects water use to a much lesser degree than the cooling system design. Because thermal, or thermoelectric, power plants using steam cycles create the primary water need for power generation, it is important to understand the installation trends in power plant prime movers (Figure 1-3) and cooling system designs (Figure 1-4).

It is relatively straightforward to measure water consumption for thermal power plant cooling for cooling towers because most of the water withdrawn is consumed, and thus needs to be replaced. The vast majority of the water withdrawn ends up being evaporated during the cooling process, and thus consumption is nearly equal to withdrawal (see Chapter 3). It is also relatively easy to measure water withdrawal, diversion, and discharge for once-through systems and recirculating with cooling pond systems. Water consumption for these systems, however, cannot be directly measured, but instead must be approximated from heat and water balance modeling. This modeling approach is how the United

States Geological Survey (USGS) estimates water consumption for thermoelectric cooling for its Water Use Survey estimating water use for 2010 (see Section 3.6) (Diehl, 2012).

Figures 1-5 and 1-6 summarize United States water use data, for both water consumption and withdrawal rates, respectively, in terms of the type of cooling system and power plant fuel (Averyt et al., 2011; Macknick et al., 2012). The figures indicate the most common combinations of power plant fuel and cooling types in the United States, but they do not represent the full range of technological options and combinations of power plant fuels and cooling systems.

The water withdrawal rates for once-through systems (ponds, canals, or lakes) are generally 5,000–50,000 gallons/MWh, one-to-two orders of magnitude larger than for cooling towers (labeled as recirculating). Consumption rates for once-through systems, usually 200–400 gallons/MWh, are due primarily to *forced evaporation* from the water bodies (lakes, streams, and reservoirs) that act as heat sinks for the power plant. Most often, natural evaporation is not reported as being associated with the power plant. *Natural evaporation* is that water evaporated from the surface of water bodies due to ambient climate conditions (air and water surface temperatures, humidity, wind speed, etc.). When thermal power plant cooling systems absorb heat from the steam cycle and discharge this heat via liquid water into the local water bodies, these water bodies now have a higher temperature than would exist without the power plant discharging heated effluent. Sections 3.6 and 3.7 provide a fuller discussion of quantifying and potentially mitigating forced evaporation.

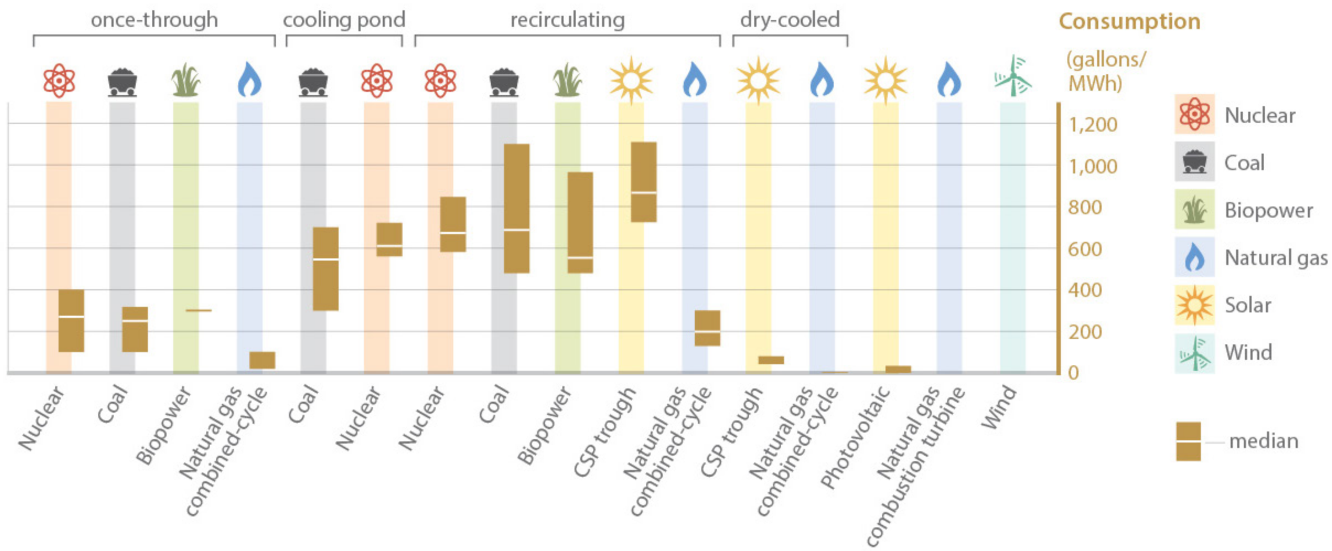


Figure 1-5. The *water consumption* rates for a power plant depend upon the prime mover, the fuel, cooling system type, and local climate conditions (reproduced from Averyt et al., 2011). Not all combinations of fuel and cooling system are shown in this figure (e.g., geothermal), but those listed are the most prominent. Upper and lower extents bars represent the range of data in (Macknick et al., 2012).

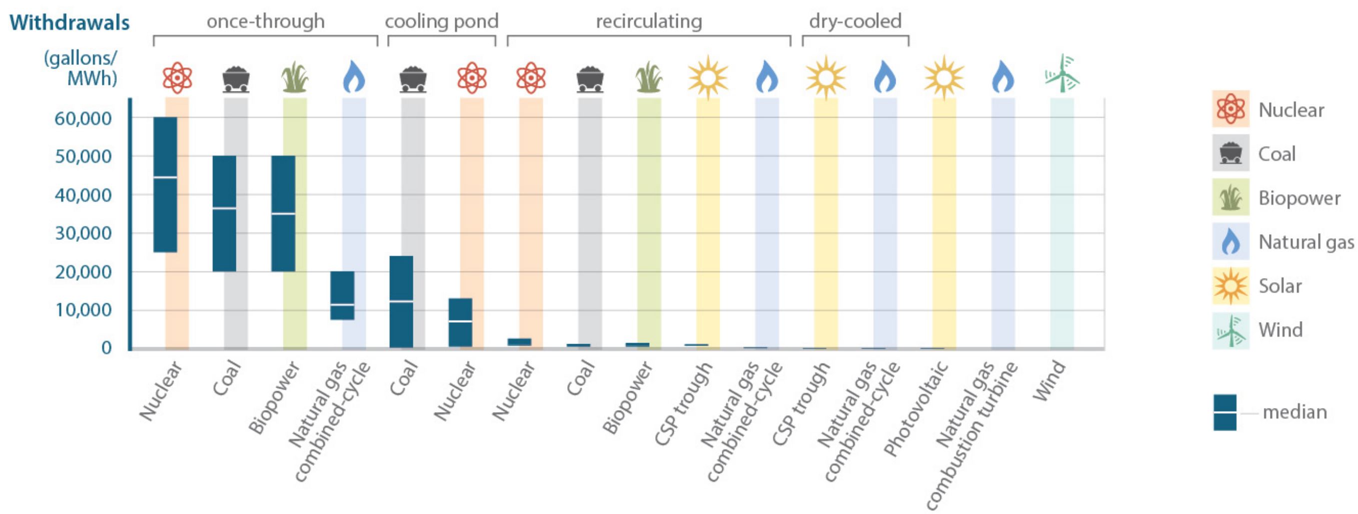


Figure 1-6. The *water withdrawal* rates for a power plant depend upon the prime mover, the fuel, cooling system type, and local climate conditions (reproduced from Avery, et al., 2011). Not all combinations of fuel and cooling system are shown in this figure (e.g., geothermal), but those listed are the most prominent. Upper and lower extents bars represent the range of data in (Macknick et al., 2012).

It is important to understand that most of the reported thermoelectric cooling data for water consumption, such as that reported to the Energy Information Administration, does not included forced evaporation. To be specific, water consumption for either once-through or recirculating cooling systems with ponds and canals (see Figure 1-2) is often reported at zero or value well below 100 gallons/MWh. The primary reason for this incorrectly low reported value of water consumption is that the power plant operator is not measuring or modeling forced water evaporation.

Consumption is often reported as equal to "withdrawal minus discharge" with respect to the power plant infrastructure (e.g., on EIA form 923), and for once-through systems, practically no water is evaporated within the condenser and other power plant infrastructure. Thus, consumption is often reported as near zero even though there is significant consumption greater than 0 gallons/MWhof generation. Also, with regard to Figure 1-2, strictly reporting consumption as equal to "withdrawal minus discharge" for systems with cooling ponds implies that all of the withdrawn water run through the condenser ends up evaporating—a gross overestimation of water consumption. For systems with cooling ponds per Figure 1-2, consumption is best represented as "diversion minus discharge." It is important to note that even this calculation represents a lower bound on consumption since precipitation (and runoff) can naturally fill cooling ponds, thus enabling lower diversion compared to a scenario with no precipitation and runoff into a cooling pond.

Withdrawal rates for wet- (recirculating) cooling towers are nearly equal to consumption rates, usually 400-700 gallons/MWh for fossil and nuclear power plants. Due to typical thermal efficiency ratings of fossil-fueled power plants between 30% and 40%, and that approximately up to 20% of the waste heat (usually 10%–15%) might flow out of the flue stack with the exhaust gases, it is usually not thermodynamically possible for them to have cooling water consumption rates higher than 800 gallons/MWh. Concentrating solar power systems (CSPs) often have slightly lower thermal efficiencies than fossil and nuclear plants, and they do not dissipate heat through exhaust gases (because there is no combustion). Thus water consumption rates are typically higher for CSP. The same rationale holds for nuclear power plants in that because they have no exhaust gases all of the heat dissipation is handled by the cooling system. Because the electricity from natural gas combined cycle (NGCC) power plants is usually only 1/3 to 1/2 from steam turbines (see

Section 3.3), there is a much lower cooling load per net power output, and hence, the water consumption for NGCC is usually 200-300 gallons/MWh if using cooling towers.

1.3 Nomenclature

CSP	Concentrating Solar Power
DC	Dry- (air-) cooling system (designation for cooling system type per EIA form 860)
EIA	Energy Information Administration
gallons/MWh	Gallons per megawatt-hour of net electricity generation
HRC	Hybrid: recirculating cooling pond(s) or canal(s) with dry cooling (designation for cooling system type per EIA form 860)
HRF	Hybrid: recirculating with forced draft cooling tower(s) with dry cooling (designation for cooling system type per EIA form 860)
HRI	Hybrid: recirculating with induced draft cooling tower(s) with dry cooling (designation for cooling system type per EIA form 860)
kWh	Kilowatt-hour
MW	Megawatt
NGCC	Natural Gas Combined Cycle
OC	Once-through with cooling pond(s) or canal(s) (designation for cooling system type per EIA form 860)
OF	Once-through, fresh water (designation for cooling system type per EIA form 860)
OS	Once-through, saline water (designation for cooling system type per EIA form 860)
RC	Recirculating with cooling pond(s) or canal(s) (designation for cooling system type per EIA form 860)
RF	Recirculating with forced draft cooling tower(s) (designation for cooling system type per EIA form 860)
RI	Recirculating with induced draft cooling tower(s) (designation for cooling system type per EIA form 860)
RN	Recirculating with natural draft cooling tower(s) (designation for cooling system type per EIA form 860)
USGS	United States Geological Survey

1.4 References

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2 The Context of Thermal Power Plant Water Usage

2.1 Power Plant Cooling as Part of a Larger Whole System

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Today there exists an array of options for technologies to generate electrical power (see Figure 1-3). Each technology has its own characteristics and depends upon unique supply chains to manufacture the necessary capital equipment and/or provide the fuel for the prime mover. Just over the last decade the United States, as well as much of the rest of the world, has seen the production and installation of more types of energy resources and technologies than in the previous century: wind turbines, photovoltaic panels, liquid biofuels, and oil and gas from shale formations, etc. These actions, together with more efficient energy consumption, are responses to the depletion of many high-quality energy stock reserves (e.g., onshore conventional oil fields) and concentrated renewable flows (e.g., rivers with high flow rates and elevation changes for hydropower). In many aspects, the reason that people engage in so much discussion, and sometimes confusion, over what type of power generation technology and fuel should be installed is because there are more options today than there were even 40 years ago. Further, there has always been, and there will almost certainly be, uncertainty about the supply and costs of future energy resources.

This section highlights where this book, focused on water use for power plant cooling, fits within the context of other factors that are important influences in choosing among power generation investments. The following factors influence the decisions to invest, install, and operate different forms of power generation, and trade-offs usually exist in trying to emphasize benefits of one factor versus another:

- Energy security
- Water security
- Air quality
- Water quality
- Greenhouse gas emissions
- Biodiversity (terrestrial)
- Biodiversity (aquatic)

Each stakeholder views one or more of these factors as important for motives related to economic viability (energy and water security), human health (air and water quality), and/or environmental protection (greenhouse gas emissions, biodiversity, air and water quality)

2.1.1 Energy Security

Energy security is the consistent and reliable availability of energy resources or the services they provide (King et al., 2013). Efforts that increase energy supply, reduce energy consumption for the same level of service (efficiency), or conserve energy consumption in aggregate (conservation) enhance energy security.

Energy security is often associated with low-cost, or affordable, energy in that energy that is more available to more individuals is generally cheaper. These words "low-cost" and "affordable" are often described relative to a person's or country's ability to produce or purchase enough energy to earn more money or grow the economy. Low-cost energy supplies, or those with high energy return on energy investment,[2] are highly correlated with and necessary for the economic growth of the modern industrialized world that we know today (Cleveland et al., 1984; Cleveland et al., 2000; Hall and Klitgaard, 2012; King, 2010; King and Hall, 2011). In many cases affluent lifestyles correlate more closely with access to electricity as compared to energy resources in general; in developing countries this often has to do with improving indoor air quality when substituting electricity for the combusting of fuels in the home for heating and cooking.

Additional security concerns related to electricity generation include services that help keep the electric grid stable as demand changes throughout the day. These ancillary services regulate grid frequency (e.g., 60 Hz) by keeping generation balanced with demand using signals to trigger demand response and instruct generators to ramp up and down and start up on time scales from seconds to half an hour. Any type of generation unit that can provide these ancillary services helps to make the overall electric grid more operationally reliable and secure.

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[2] Energy return on energy investment, or EROI, is the quantity of energy that is produced and/or delivered divided by the energy that is required to produce and/or deliver that energy resource.

In light of the value of water for large-scale thermoelectric power plants that are the topic of this book, I quote here from the case study in Section 5.3: "The cost of disruption to energy production, such as electricity generation, far outweighs the direct costs to the energy sector for this water. Even without disruption, the marginal product of water consumed in the electricity industry exceeds what is usually paid for it, and is far above many competing users." In other words, there is a high value to using water for power generation because there is a high value to using a reliable electricity supply for economic activity. As Chapter 4 discusses, it costs more to install "dry" or "air-cooled" thermal power plant cooling systems, but the costs are acceptable in many situations, particularly in water-scarce regions such as the western U.S., Australia, and South Africa (see Chapter 5 case studies). In some instances, dry cooling technologies enable economic operation of thermal power generation in water-scarce regions that otherwise would have to spend too much to secure water supply.

2.1.2 Water Security

Water security is the consistent and reliable availability of freshwater or the services it provides (King et al., 2013). Generally, water security is enhanced by efforts that increase freshwater supply, reduce freshwater consumption for the same level of service (efficiency), or conserve freshwater consumption in aggregate (conservation). Historically, societies that have water security have been able to successfully expand agriculture and increase living standards.

Wet-cooled power plants incorporating once-through systems, recirculating with cooling ponds, and wet-cooling towers withdraw and consume water from the environment that could otherwise go toward other human economic activities or ecosystem services. Thus, in the most simplistic sense, they reduce water security. However, this reduction in water security provides for energy and economic security, such that for most power plants in most water basins, the trade-off has provided net benefits to society.

Much of the context of this book weighs the trade-offs between water and energy security related to power plant water use. It is up to the stakeholders in each water basin to determine if water use by thermal power plants is appropriate relative to the water availability and other water uses in the basin. For further discussion of the energy-water nexus trade-offs relating to an array of technologies and policies, see reference (King et al., 2013).

2.1.3 Air Quality

Poor air quality usually refers to air degradation due to emissions such as nitrogen oxides, sulfur oxides, mercury, and particulate matter. These emissions are associated with thermal power generation systems that burn fossil fuels or biomass, and they can cause air pollution that results in negative environmental conditions such as ground-level ozone and acid rain. Ground-level ozone can be harmful to human health when breathed. People with lung disease, children, older adults, and people who are active outdoors may be particularly sensitive to ozone (EPA, 2013a). Airborne particulate matter, such as soot, can also impair breathing.

Emissions control systems exist for coal, natural gas, and biomass-fired power plants to reduce emissions, and these systems also often consume water for their operation (see Section 3.3 for discussion of water for NOx control on combined cycle power plants). For example, flue gas desulfurization systems, used to scrub SO_2 emissions from coal-fired power plants, consume approximately 40-70 gallons/MWh (Feeley III et al., 2008). Cooling systems themselves, particularly wet-cooling towers, also have air emissions including water vapor (that can freeze on roads during winter) and salts if using saline waters (though using saline water in cooling towers is uncommon). Cooling systems emissions are also regulated similar to flue gas emissions.

Some power generation technologies do not emit harmful air emissions during operation: nuclear, solar (photovoltaics and concentrating power systems), wind, geothermal energy ("steam-dominated" geothermal plants emit hydrogen sulfide), wave, and tidal power generation. This lack of emissions is an advantage of these technologies to consider among the other factors in this section. Because renewable solar and wind power outputs are variable depending upon the immediate weather conditions, considerable research effort is often spent to understand the net impact of renewable generation on the timing and location of air emissions and water use from the fossil-fueled power plants within an entire electric grid (Alhajeri et al., 2011). It is also important to recognize that air emissions from mobile sources, such as cars, trucks, and heavy machinery, contribute the majority of air emissions in metropolitan areas (Thompson et al., 2009).

2.1.4 Water Quality

During the life cycle of water usage, thermoelectric systems can affect water quality. Section 2.2 discusses these environmental impacts and their regulation. Because power plants and other industrial facilities that generate on-site power are what are called *point source emitters*, water quality impact can be relatively easily regulated, measured, and controlled. Other point-source emitters that can affect water quality (contaminants, temperature, turbidity) are water and wastewater treatment plants. In contrast, *nonpoint source emitters*, such as agricultural farming operations, are more difficult to control and directly measure water quality impacts from discharges and runoff.

2.1.5 Greenhouse Gas Emissions

Most climate scientists have concerns about the long-term negative impact of accumulating greenhouse gases (GHG) in the atmosphere and believe humans are the major cause of this accumulation (Cook et al., 2013). This accumulation of GHGs has occurred due to human activities, largely the result of burning fossil fuels, but also due to agricultural practices and deforestation. In order to limit the expected impact of climate change due to GHG accumulation, some propose reducing annual global GHG emissions to between 20% and 50% of the annual emissions during the last decade by the targeted time frame of 2030–2050 (IPCC, 2007). To generate the same or higher *quantity* of electricity relative to today, every power plant will have to either not emit GHG during operation (e.g., be non-fossil) or be a fossil fuel power plant using carbon dioxide capture and storage technologies. Achieving these targeted annual GHG emission reductions will require an unprecedented transformation of our entire energy system, and not only within power generation systems and networks. Thus, the quantity of GHG emissions from power generation is now usually a major factor in choosing whether or not to install or operate a power plant.

2.1.6 Biodiversity—Terrestrial

Land use is one measure of the impact on terrestrial habitat. Agriculture is the purpose for the vast majority of human-appropriated land use, but for specific cases, even relatively small footprints of 10s to 100s m^2 can have measureable negative impact. For this reason it is important to consider where and how much land use will occur for energy production life cycles.

The encompassed land area footprint of the actual power generation infrastructure is considerably smaller for thermal power plants (fossil fuel, nuclear, geothermal, and biomass) compared to solar and wind farms that extract diffuse insolation and wind power flows. The thermal power plants need cooling of their steam cycles, and thus typically withdraw and consume water for this purpose. The dry-cooling systems discussed in Chapters 4 and 5 eliminate the need for cooling water, but at some expense of increased land footprint for those systems—of the same magnitude as the non-cooling portion of the power plant.

Thermal power plants, including cooling systems, typically have area power densities of 100 to 1,000 W/m^2 (covering 0.0001 to 0.003 km^2/GWh of generation at 85% capacity factor) even when considering land disturbance for coal mining (Smil, 2008). Gas turbines need even less land per power output at 4,000 to 5,000 W/m^2 (covering $<$ 0.001 km^2/GWh of generation at 30% capacity factor) (Smil, 2008). Dedicated cooling ponds for $>$ 1 GW power plants can cover over 25 km^2, and one large nuclear power plant in Texas uses a 7,000 acre cooling pond (28 km^2) (King et al., 2008a). Mechanical draft wet-cooling towers for a 1,200 MW nuclear plant can take 0.06 km^2 (15 acres), and as later discussed in Chapter 4, dry-cooling systems can take four to six times more land. For practical purposes, no other activities or ecosystem services exist within the footprint of the thermal power plant infrastructure (lakes and ponds used for cooling can still provide habitat for aquatic biodiversity).

Solar photovoltaic and concentrating solar power plants have area power density of 5 to 20 W/m^2 encompassing 0.01 to 0.1 km^2/GWh of generation at 28% capacity factor. Wind farms have area power density near 2 W/m^2, or approximately 0.2 km^2/GWh at 35% capacity factor (MacKay, 2009; McDonald et al., 2009). Solar farms cover most of the land that they encompass since the collected solar insolation is a function of the collection area. On a wind farm the turbines are typically separated by 500 to 2,000 m, such that there is much land in between that can be used for farming and ranching. Depending upon the situation, biodiversity might or might not thrive among wind turbines. As an example, ground birds, such as the sage grouse and prairie chicken, are negatively impacted by oil and gas drilling infrastructure and power lines as these give perches to the birds' predators (Becker et al., 2009; Pruett et al., 2009). Thus, wind turbines, solar panels, and additional transmission lines installed in their habitat might only exacerbate the existing situations.

2.1.7 Biodiversity—Aquatic

Our choices for future energy supplies can also impact aquatic environments and marine biodiversity. Focusing on water impact, there is a body of literature that has established the impact of changing water flow, sediment, water quality, and thermal regimes on freshwater biological diversity (Annear et al., 2004; Bunn and Arthington, 2002; Poff et al., 1997b; Poff and Zimmerman, 2010). Water withdrawal and consumption by the energy sector may increase in some areas and alter water quality and quantity in freshwater ecosystems, thus further threatening an already imperiled fauna. McDonald et al. (2012) statistically related historical water use by the energy sector to patterns of fish species endangerment, where water resource regions with a greater fraction of available surface water withdrawn by hydropower or consumed by the overall energy sector[3] correlated with higher probabilities of imperilment.

Even though withdrawal, consumption, and discharge of water, including that by thermoelectric power plants, *can* impact biodiversity in a negative manner, this does not mean that it always *will* do so. Aquatic flora and fauna are adapted to the natural variations in the local water flows and temperatures of their habitat. Any changes to these patterns could have positive or negative impacts, and that is why it is important to consider the site-specific conditions when regulating the water impact of power plants that use water. Some of these site-specific concerns can consider if the local biodiversity experiences benefit from or harm water discharges, if any harm is significant enough to decrease populations of wildlife, as well as whether or not the affected local biodiversity is native or invasive. In this way, local stakeholders could discuss, for example, whether any fish harmed by power plant water use are a desired species for the local ecosystem.

[3] McDonald et al. (2012) allocate 100% of water evaporation from hydropower reservoirs to hydropower. Thus, reservoirs in general might be viewed as impacting fish habitat more so than hydroelectric power specifically.

2.1.8 Role of Integrated Water Resource Management

In the context of the total water withdrawal and consumption for all human and environmental demands, any two people can debate how important thermoelectric water use is relative to all others. Amenable conclusions to these debates are often resolved during the process of *integrated water resources management* (IWRM). IWRM is a collaborative engagement process with the goal to consider ecosystem health and biodiversity in tandem with other goals for freshwater use, such that management of water resources is as fair and equitable as possible to all water users. Technically, no water use or impact is excluded within IWRM; practically, all uses and impacts will not be addressed to full satisfaction by all.

When engaged in IWRM to create site-specific policies and best management practices that affect energy and water resources, one can consider objectives related to the various impacts briefly discussed in this section, as well as other factors not mentioned here. Some energy technologies and systems benefit one objective more than another. Thus, any individual technology, management practice, or policy can be simultaneously viewed in the context of each of these broad strategic objectives (e.g., low cost, safe air quality). A previous work by this author and his colleagues has investigated the coherence between energy and water objectives (King et al., 2013). The rest of this subsection on IWRM summarizes some aspects for considering thermal power plants' water use in relation to watersheds and other water uses.

While often neglected historically in water planning, energy production systems should be an integral consideration. For example, some recent impacts have been that drought and high water temperatures are influencing the ability of thermoelectric power plants to fully operate and/or meet regulatory limits across the United States, from Texas to the Midwest to Connecticut (see Section 2.2 for discussion of U.S. regulations of thermal discharges) (Flessner, 2010; Reuters, 2011; Wald, 2012; Wald and Schwartz, 2012). In this sense, we can ask about the sensitivity of our power plants to future droughts and/or any future global temperatures increases. In any particular case, it can make sense to adapt and modify the power plant cooling infrastructure, provide more water supply, adapt market structures to enable water trading, or engage in water and energy conservation activities.

Because of the difference in power plant cooling system withdrawal and consumption rates, one could argue that power plants "use" a lot of water or "use" little relative to all water used for human purposes. From the standpoint of total annual water withdrawal in the U.S., thermoelectric power plants withdraw more water than for irrigation—approximately 49% of the total U.S. water withdrawal of 350 billion gallons per year (Kenny et al., 2009). On the other hand, from the standpoint of water consumption, thermoelectric power plants use 3% to 4% of total U.S. water of approximately 100 billion gallons per year, whereas water consumption for crop irrigation and livestock is over 80% (Solley et al., 1998). Thus, it is useful, but not always straightforward, to think of the future water use of power plants in the context of water basins and other competing water uses as done during integrated water resources management.

Over the last several years, there has been a significant rise in the body of research characterizing implications and changes in U.S. water consumption and withdrawal for future energy supply scenarios associated with both high and low greenhouse gas emissions (Averyt et al., 2011; Chiu and Wu, 2012; DOE, 2006; King et al., 2008b; King and Webber, 2008; Macknick et al., 2011). Thus, information exists to assess regional changes in water use associated with future energy scenarios, but because of various factors ranging from energy resource constraints to economic conditions to climate mitigation policies, no one can accurately predict the series and distribution of future energy investments in the U.S. In general, it seems that many of our future low- and high-carbon energy options are more water intensive (e.g., higher water input per energy output) than past energy supplies. U.S. energy-related water consumption, and possibly withdrawal, are expected to increase in business-as-usual (BAU) scenarios, but likely more so for low-carbon and biofuel-intensive scenarios.

In terms of the energy-water nexus in general, there are different anticipated water impacts for transportation fuels and electricity life cycles as currently there is very little coupling between electricity generation and transportation fuels. Considering energy for transportation, by 2030 an estimated 4 to 5 billion gallons per day, or 4% to 5% of U.S. total, could be consumed for production of fuels only for light duty transportation (King et al., 2010). This water quantity would be primarily for irrigating feedstock for low-carbon biofuels but also for some large regional consumption for unconventional fossil fuels. Considering both BAU and low-carbon electricity generation scenarios up to 2030, U.S. thermoelectric water withdrawal is expected to slightly decrease by 2% to 14%, and water consumption is expected to increase by 24%- to 2% (Chandel et al., 2011). If there is a future increase in electrified travel, then water use for power generation will become a larger part of the transportation life cycle. If U.S. travelers drove three trillion miles per year[4] using only light-duty electric vehicles, that would necessitate 25% more generation on top of existing electrical generation and associated water use (King and Webber, 2008).

As with all water uses, there will be significant regional differences in water-related impacts driven by power generation portfolios, local water availability, and other economic activities. As this book is focused on water for thermal power plant cooling, keep in mind how power plants fit within this broader context.

[4] U.S. total vehicle miles traveled were approximately three trillion from 2005 to 2010. See Federal Highway Administration data at http://www.fhwa.dot.gov/policyinformation/travel_monitoring/tvt.cfm.

2.2 Environmental Considerations for Power Plant Water Usage

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All thermoelectric power plants impact natural ecosystem functions, but the magnitude and duration of those impacts depend on the specific operation of each facility as well as the character of the habitat in which it is sited. To effectively work within one's regulatory setting by minimizing adverse environmental impacts, it is essential to understand the local environment, native species, ecosystem dynamics, and sensitivities. The purpose of this section is to outline the major causes and effects of ecosystem impact from thermoelectric power plant operations, with an emphasis on impacts that are of regulatory concern in the United States. A brief history of the relevant U.S. environmental laws is also provided.

Environmental stresses occur at the level of individual organisms (e.g., *morbidity*, *mortality*) and entire populations (e.g., biodiversity changes). In the context of water use by thermal power plants, these stresses are often the result of one or a combination of the following three factors: rate and timing of cooling water **withdrawals** and **discharges**, the level and variability of discharge **temperatures** (particularly for once-through facilities), and chemical pollutant **concentrations** within effluent streams. Ecosystems are highly complex networks, which means that changes in any one of the preceding conditions may result in unpredictable outcomes. It is not trivial to cope with the uncertainty of interactions between human-engineered systems and the environment, but use of the best site-appropriate technologies coupled with adequate biological monitoring can significantly reduce the likelihood of regulatory noncompliance.

The following discussion provides some guidance to power plant owners, operators, and siting decision makers in light of the potential environmental effects that normal thermoelectric facility operations can have. Note: Ecosystem sensitivities are intensely location specific (Veil et al., 1993). Broad statements about the significance of particular operations on aquatic biota may be irrelevant for any one location. While the need to ensure habitat integrity is universal, the precise conditions under which that need is met are not.

2.2.1 Environmental Effects of Thermal Power Plants

2.2.1.1 Impingement, Entrainment, and Flow

Riverine and estuarine ecosystems develop as the result of long-term patterns of seasonal changes to physical and chemical conditions. The periodicity, magnitude, and quality of freshwater and brackish water inflows and outflows are important for the health and development of aquatic species (Poff et al., 1997a; Wilson and Dibble, 2010). At the water intake, water velocities higher than 0.5 ft sec^{-1} can increase the likelihood that organisms will be caught on the intake screen (impingement) or that larvae and eggs will be destroyed within the cooling system itself (entrainment) (Barnthouse, 2000; EPRI, 2000). At the point of discharge, volumetric flow rates should be adequately high in order to maintain downstream water availability, and in cases where the points of intake and discharge are very close to each other and no intermediate process steps effectively impound water flows (e.g., filling cooling ponds), volumetric flow maintenance is easily accomplished. However, the velocity of discharge flow cannot be so high that it leads to bank scouring (EPA, 2006), benthic habitat destruction (Reiley, 1992), and increased turbidity. Reduction of benthic grasses, in particular, diminishes fish spawning area.

Constant, unchanging water flows are unusual in nature. Stream flow regimes may vary on a daily, weekly, and seasonal basis (Sovacool and Sovacool, 2009), and often host organisms are specially adapted to such variation. In order to minimize adverse impacts, timing of the cooling water flow by either operational or design modifications would have to account for the natural variability of its nearby freshwater body as a point of reference. For example, high pumping rates at the intake when water levels are low may increase the likelihood of organismal mortality as refuge space becomes limited. Likewise, high flow rates at the point of discharge during low tide in an estuarine setting lower the ability of the downstream water body to absorb the kinetic (and thermal) energy of the effluent and, therefore, increase the likelihood of ecosystem strain.

Fish diversion devices at the point of intake can minimize instances of harm to fish, even when cooling water flow rates are fixed. Types of barriers include conventional traveling screens, modified traveling screens with fish return technology (e.g., Ristroph), cylindrical wedge-wire screens, fine mesh screens, fish net barriers, aquatic microfiltration barriers, louver panels, angled and modular inclined screens, velocity caps, porous dikes and leaky dams, and behavioral barriers (EPA, 2012b).

2.2.1.2 Thermal Pollution

Thermal discharges are water outflows from power plants that are of a higher temperature than ambient stream conditions and that can be a form of pollution. Because once-through cooling systems discharge nearly 100 percent of the water that they take in, thermal discharges are primarily an issue for once-through cooled facilities, due to higher discharge flow contribution from heated water. They represent another type of risk factor for aquatic organisms.

In many cases the heat flux to the downstream environment (and resulting change to average downstream temperatures) is the parameter of interest. The maximum or average allowable discharge temperature at the outfall is then calculated by considering the volume of the thermal discharge, as well as the volume and flow of the receiving water and the area of the mixing zone that dictates the size of the thermal plume (Reiley, 1992). Thus, a low volume, high temperature discharge may have the same temperature effects on downstream ecosystems as a high volume discharge of a lower temperature.

While the temperature above which local species are unable to maintain health is site specific, at least 14 of the 15 U.S. states with the most once-through cooling systems[5] have set standards to ensure that freshwater temperatures do not exceed 32.2°C (90° F) (Madden et al., 2013). High temperatures reduce dissolved oxygen availability, which can limit the distribution of fish and macroinvertebrates, reduce growth rates, and alter nutrient and carbon cycling (Langford, 1990). In addition, anoxic conditions tend to increase ammonia concentrations, contributing to an ecosystem condition known as eutrophication, in which growth rates of aquatic plants species (e.g., algae) rapidly increase, followed by a period of anoxia as aerobic bacteria begin to decompose the plant material (Art and Botkin, 1993; National Research Council, 2012).

[5] Including AL, GA, IA, IL, IN, KY, LA, MI, MO, NY, OH, PA, VA, and WI.

Sudden changes to the discharge temperature, either in a positive or negative direction, can result in *morbidity* and *mortality* of fish and other organisms due to thermal shock.[6] One method of ensuring that thermal shock does not occur is by preventing the temperature rise from the intake to the point of discharge from exceeding some maximum, thereby limiting the amount of heat that is discharged into the downstream habitat over a short period of time. Sudden shutdown of generating units leading to a rapid decrease in the temperature of the effluent water can also be detrimental. During the winter months in colder climates, fish tend to congregate in heated effluent plumes. The sudden shutdown of a generating unit might not leave time for acclimated organisms to adjust to the colder temperatures (Reiley, 1992).

Mobile aquatic organisms avoid moving through high gradients (e.g., temperature, light, salinity), and so thermal effluents may present significant migration barriers to fish where they impair or completely block passages (Bates, 2000). Warm water may also reduce the extent of spawning area for the same reason.

2.2.1.3 Chemical Pollution

Chemical pollutants are also regulated through the EPA's National Pollutant Discharge Elimination System (NPDES) program, which sets permit limits for total maximum daily loads of various chemicals within cooling water and tower blowdown effluents. For non-contact cooling water discharges, the Clean Water Act through NPDES also regulates cooling additives such as anti-corrosives, descaling agents, and biocides because they may cause harm to downstream aquatic populations, either through acute or chronic exposure (Poornima et al., 2006). Boiler and cooling tower blowdown represents a more significant, though intermittent, chemical pollutant stream than non-contact cooling water. Blowdown often contains high concentrations of salts, metals, and other dissolved solids. Very high concentrations can cause direct mortality, while lower concentrations may cause morbidity (e.g., developmental impairment, low productivity).

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[6] For specific examples of where and why thermal shock may occur, see Reiley, 1992, p. 8-10.

2.2.1.4 Seasonal Effects

Seasonality plays a significant role in dictating the degree of impact that a power plant's cooling operations will have on nearby ecosystems. Summer months can be an especially difficult time to abide by environmental regulations. The combination of increased ambient and effluent temperatures, as well as altered stream flow, reduced oxygen, and chemical pollutants can stress aquatic organisms, increasing rates of bacteriological and parasitic infection (Reiley, 1992). If left unchecked, the cumulative environmental impacts can cause long-term changes to ecosystems dynamics, such as lower species diversity, reduced native species population sizes, and proliferation of invasive species (Brandt, 2010). NPDES permits often include seasonal variations to account for such sensitivities, presenting the power plant operator with the difficult task of meeting both electricity demand and regulatory obligations.

2.2.2 Regulatory Context

In the United States, federal authority to regulate the pollution of public waterways for the protection of human populations, fish stocks, recreational uses, and general environmental well-being has a long historical precedent. Many of the early successes of such regulation in correcting water quality problems led to a strengthening of the original legislation through time—a process that continues today (Poe, 1995).[7] Table 2-1 lists many of the significant water-related regulatory acts for the United States.

[7] For a fuller description of the purpose and evolution of the Clean Water Act through time, see Poe, 1995.

Table 2-1. Timeline of significant United States regulatory acts relevant to power plant cooling.

1899	Refuse Act (RA)	
1948	Water Pollution Control Act (WPCA)	
1965	Water Quality Act (WQA)	
1970	National Environmental Policy Act (NEPA)	Requires that all Federal agencies prepare environmental impact statements for, and alternatives to, major Federal actions
1972	Federal Water Pollution Control Act (FWPCA, Clean Water Act, CWA)	Shifted the focus to technology standards rather than causal relationships between dischargers and ecosystems
1972	Coastal Zone Management Act (CZMA)	
1973	Endangered Species Act (ESA)	Passed to protect critically imperiled species from extinction; species are identified as part of a federal registry
1977	CWA Amendments	
1987	Water Quality Act	
1990	Coastal Zone Act Reauthorization Amendments	
2011	Proposed changes to CWA Section 316(b)	Flexible technology standards for intake structures at thermoelectric plants to reduce impingement and costs
2013	Official changes to CWA Section 316(b) due	

2.2.2.1 Acts and sections Relevant to Thermoelectric Power Plants

Table 2-2 lists some sections of the preceding regulations in Table 2-1 that are most relevant to thermoelectric power plant operations.

Table 2-2. Important sections of United States water regulations for the context of power plant cooling.

CWA Sec. 316(a) Variances	Authorizes NPDES permitting authorities to impose alternative thermal effluent limitations in lieu of the effluent limits that would be required under CWA Sections 301 or 306. Establishes concept of "Best Professional Judgment" (BPJ) authorization. Allows for "Balanced, indigenous populations" (BIP) demonstration in lieu of federal or state standards and based on BPJ. Variances require renewal every 5 years. (EPA, 2008)
CWA Sec. 316(b)	Provides compliance standards for cooling water intake structures based on Best Technology Available (BTA). Technology standards are expected to be more flexible and site-specific beginning in 2013, based on federal findings.
CWA Sec. 402	Requires states to develop their own State Pollutant Discharge Elimination System or to abide by the National Pollutant Discharge Elimination System (NPDES).
CZMA Sec 306(d)(2)(H)	Requires state management programs to include plans for anticipated impacts from energy facilities. It affects all actions requiring a federal license or permit, such as NRC and NPDES permitting.
ESA Sec. 4	Disallows the destruction of critical habitat for endangered species by federally funded projects.
ESA Sec. 9	Establishes that the "taking" of species listed as endangered is illegal. Many listed species have particular water needs, including temperature and flow requirements.

2.2.2.2 Proposed Changes to the CWA 316(b) Regulations Affecting Steam-Electric Power Plants

The Environmental Protection Agency (EPA) divided the rule-making process to fulfill its obligations under Clean Water Act 316(b) into three phases. Phases II and III cover existing large-scale electric generation facilities and small electric-generating facilities, respectively. Subsequent legal proceedings in 2010[8] remanded the Phase II and III rules to the EPA for reconsideration (EPA, 2012b), in light of the failure of the existing rules to fully meet the 316(b) rules of habitat protection. In response, the EPA published a series of rules for comment and consideration in 2012 (EPA, 2012c).[9] During the public comment period, the EPA received extensive new information in the form of reports and other documents, including raw facility-level data to support or challenge its proposed rules. Where raw data was not provided or the information in the comments was incomplete, the Agency conducted follow-up visits to affected power plants and manufacturing facilities in order to obtain more complete input (EPA, 2012a).

The proposed rules are intended to set flexible, site-specific technology standards in order to minimize environmental damage, especially to sensitive fish and shellfish populations (EPA, 2011a). The original 2012 deadline was extended, and the final rules are currently scheduled for publication on **November 4, 2013** (EPA, 2013b). Once the final rule is effective, the facility would have to meet the standards within **eight years**. New generating units to be installed at existing facilities must comply with the new regulations by the time the units are operational.

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[8] See Cronin et al. v. Reilly, 98 CIV. 314 (LTS) (SDNY); Riverkeeper, Inc. v. U.S. EPA, 358 F. 3d 174, 181 (2d Cir.2004) ("Riverkeeper I"); Riverkeeper, Inc. v. U.S.EPA, 475 F. 3d 83 (2d Cir. 2007) ("Riverkeeper II").

[9] See Chapter 11 of the Technical Development Document (DCN 10-0004, EPA-HQ-OW-2008-0667-1282) for the EPA's most recent proposed criteria EPA (2012c) Notice of Data Availability Related to the EPA Stated Preference Survey for Proposed Regulations to Establish Requirements for Cooling Water Intake Structures. U.S. Environmental Protection Agency. Available at http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/upload/Notice-of-Data-Availability-Related-to-the-EPA-Stated-Preference-Survey-for-Proposed-Regulations-to-Establish-Requirements-for-Cooling-Water-Intake-Structures-Factsheet.pdf.

The EPA estimates that the proposed Phase II changes affect approximately 1,260 facilities, of which 670 are steam-electric plants and 590 are manufacturers (EPA, 2012c). The EPA also estimates that roughly 59 percent of the affected facilities already use technologies that meet the standards of the updated regulations. No new technologies need to be developed for compliance at existing facilities, although the costs of installing existing technologies or implementing operational changes will vary from facility to facility (EPA, 2011a). New facilities must continue to comply with the CWA 316(b) Phase I Rule, which was passed in 2001.

The proposed changes affect existing facilities, including power plants and manufacturers that withdraw at least **two million gallons per day** to dissipate waste heat, and will be implemented through the existing National Pollutant Discharge Elimination System (NPDES) program. Modified NPDES permits would more rigorously define acceptable standards for the "location, design, construction, and capacity of cooling water intake structures" (CFR, 2012) that are comparable to the success rates of the best technology available (BTA). The EPA concluded that the BTA for reducing the rates of mortality caused by impingement are modified traveling screens. The new rules would not require facilities to install such screens, but the reduction in fish impingement mortality must be proven to be equivalent to the theoretical success rate of such screens for a given facility's location (options appear below). Entrainment reduction requirements are even more site-specific.

Upon last reporting, the proposed Phase II regulations will have two major components (CFR, 2012). These components were selected based on a rigorous benefit-to-cost analysis carried out by the EPA[10]:

1. **Impingement mortality (IM)** – Based on the data received by the EPA and a statistical analysis of field data at three

[10] The benefit-cost analysis was intended to maximize national benefits and minimize associated costs to industry and customers. A willingness-to-pay (WTP) survey and model was used to estimate benefits on a regional basis across the United States EPA (2012d) Survey Support Document – In Support of Section 316(b) Stated Preference Survey Notice of Data Availability. U.S. Environmental Protection Agency. Available at http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/upload/surveydoc.pdf.

representative facilities, the *monthly impingement limitation is proposed to be 30 percent*, while the *annual average impingement limitation is proposed to be 12 percent* (EPA, 2012c).

The limits would be expressed as a monthly average and yearly average. The facility managers are left to decide what technology is best able to meet the standard, and facilities must demonstrate the performance through direct fish mortality sampling. Equation Eq. (2-1) is used to determine IM percentage (EPA, 2012d)[11]:

$$\%\,\mathrm{IM} = 100 \times \frac{\text{impinged fish that are killed}}{\text{total number of impinged fish}} \qquad \text{Eq. (2-1)}$$

Alternatively, the facility may comply by pursuing operational or design changes that reduce speeds through the intake screen to **0.5 feet per second (fps)[12]—**the level below which most fish can avoid impingement. As it makes its final ruling, the EPA is considering additional flexibilities for IM compliance.[13]

2. **Entrainment** – EPA has not proposed numerical entrainment limitations, due to the substantial variation in organismal life stages, intake mesh slot sizes, and intake velocities shown in its source data. The rules are likely to leave most of the responsibility of assigning standards to the state permitting authority on a facility-by-facility basis.

Therefore, as part of their NPDES permit application, all facilities would have to report relevant, site-specific environmental information in order to allow the permit authorities to make a determination about the

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[11] Federal Register June 11, 2002, provides a simplified example of how the denominator of the IM equation may be modified to account for impingement mitigation technologies and practices already in place.

[12] 66 Federal Register 65256, December 18, 2001, Section V.B.1.b.1.

[13] Including but not limited to pre-approval of some technology types, exceptions for facilities that currently have very low impingement rates, modifications to the equation used to calculate observed IM to account for location and other site-specific variables, as well as flexibility in calculating flow velocity through indirect measurements (e.g., pressure differential, plant intake flow).

type of entrainment mitigation technology needed (if any). Additionally, facilities that withdraw more than **125 million gallons per day** will be required to conduct and submit to the permitting authority comprehensive environmental studies. This process must include public input.

While the EPA is unlikely to exempt facilities that employ recirculating cooling towers from the regulation outright, they note that the majority of such systems already meet the 0.5 fps flow limitation criteria. Furthermore, the Agency does not intend for facilities to install closed-loop systems solely for the purposes of meeting the impingement mortality standards, although it estimates that such retrofits would likely reduce water intake rates by greater than 90 percent at most facilities, thereby surpassing the compliance threshold.

2.2.3 EPA Analysis of Costs and Benefits of Retrofitting From Once-Through Cooling to Cooling Towers

The EPA analyzed costs and benefits of compliance with 316(b) and found that the initial capital cost for retrofitting cooling towers per electricity facility will average $308 million in 2009 dollars given a 3% discount rate (EPA, 2011d). Nationally, annualized social costs of compliance were estimated at $383 million, while the annualized social benefits were estimated at $17 million, both in 2009 dollars, given a 3% discount rate. Additional monitoring costs and implementation costs for the proposed regulations are covered in the **Economic and Benefits Analysis (EPA 821-R-11-003)** (EPA, 2011b). The proposed compliance is expected to reduce fish mortalities due to impingement and entrainment by 0.6 billion/yr. The detailed national benefits analysis is presented in **Environmental and Economic Benefits Analysis (EPA 821-R-11-002)** (EPA, 2011c)**.**

The EPA has published three support documents that outline, in great detail, the purpose, history, and scope of the new Phase II and III rules. These support documents also contain specific guidance for power plant and other facility managers who must decide how best to meet the new standards while considering environmental and economic benefits and costs. The most useful of these from the perspective of facility-level decision-making is the Technical Development Document, which provides a record of the progress of the proposed CWA 316(b) Phase II and III rules, as well as the methodology used by the EPA throughout the course of its investigation (EPA, 2011d).

Additional information (including links to the three major support documents) is available at the following website: http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/index.cfm

2.3 Balancing Thermoelectric Power Production and Thermal Pollution

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Thermal pollution from power plants raises the natural temperature of receiving waters and is a well-known concern for the integrity of aquatic ecosystems and biota (Stewart et al., 2013; Vörösmarty et al., 2010). The Clean Water Act (1972) (CWA) was enacted to mitigate thermal pollution and provide at least some protection for riverine ecosystems (EPA, 1998). Thermal pollution is not only a concern for aquatic life; thermal pollution can also raise river temperatures to the point that a downstream power plant will suffer a loss in efficiency and hence power production (Miara and Vörösmarty, 2013). The magnitude of thermal pollution impact and water use depends greatly on the cooling technology, prime mover, and grid fuel mix at the power plants (see Figure 1-5). Furthermore, imminent strategic planning trade-offs facing the thermoelectric sector, such as selection of cooling water sources, mitigating and adapting to climate change, adhering to CWA temperature limits, and satisfying increased electricity demand, all play out in a multi-plant context, arguing for regional frameworks to identify optimal energy sector configurations. In this section, the range of thermal pollution impact in the thermoelectric sector is discussed, as well as the potential societal benefits of co-balancing ecosystem service protection and electricity production."

Water available for cooling purposes is a crucial ecosystem service for the thermoelectric sector (Feeley III et al., 2008). In the context of power plant operations that depend on river water, this service can be defined as a sufficiently abundant volume of river water with sufficiently cool temperatures, which in turn attenuates and conveys heat downstream by river networks as demonstrated in Stewart (2013) (Hamanaka et al., 2009; Stewart et al., 2013; VGB PowerTech, 2008). In that study, the geospatial and time-varying dynamics of Northeastern U.S. river networks were simulated and validated, including thermal loads from power plants, river discharge, and temperatures, for the years 2000-2010. During summertime, power plant operations are constrained as water temperatures naturally warm, possibly enough to raise the pressure at the power plant condenser. This increase in pressure leads to an increase in turbine backpressure, producing a lower thermal efficiency, meaning that less heat produced from the fuel source is converted to electricity (Mirjana et al., 2010). Under such conditions, power plants can interfere with each other, with thermal pollution from upstream plants raising river temperatures at the intake points of downstream power plants, thereby reducing power production even further. Figure 2-1 shows results from simulating these thermal effects over the average summer (2000-2010) in Northeastern U.S. rivers. In contrast, water temperatures in the winter are typically cool enough for optimal operations and the effect of thermal pollution on downstream electricity production is non-existent (Miara et al., 2013).

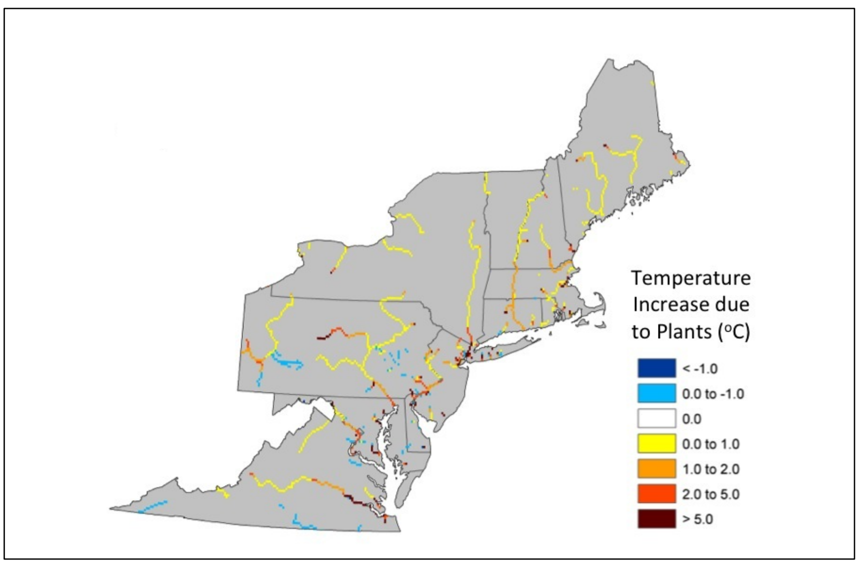

Figure 2-1. The increase in river temperatures over the average summer (2000-2010) due to thermal effluents from Northeast U.S. power plants as simulated in (Stewart et al., 2013). There is a clear sign of warming due to

thermal pollution (red). Some river segments show a decrease in temperature due to the effects of cooling towers (blue).

The CWA (1972) river temperature regulations obligate power plants to reduce thermal effluents as river temperatures approach and exceed established thresholds. If power plants are forced to reduce their thermal discharges, the efficiency of the cooling process is greatly diminished and electricity output decreases (Hamanaka et al., 2009). Consequences of regulatory temperature limits have already been observed in recent summers, in both the U.S. and Europe (Averyt et al., 2011).

Approximately one-third of power plants in the U.S. benefit from section 316(a) variance permits, allowing them to raise river temperatures above default regulatory limits (Veil et al., 1993). Upstream thermal pollution from power plants with waivers can raise river temperatures to the extent that a downstream power plant will be required to curb its thermal discharge.

To advance the analyses of riverine ecosystems and their interactions with power plants, Miara and Vörösmarty (2013) developed the Thermoelectric Power and Thermal Pollution Model (TP2M), a dynamic model that simulates power production and thermal pollution according to electricity demand, power plant engineering characteristics (i.e., cooling technology), river water availability and temperature, and environmental regulation. Ironically, in Miara and Vörösmarty (2013), CWA variance permits that allow for larger electricity output at the individual plant level could in fact cause lower regional electricity production, as they degrade the quality of the water available for cooling. In that theoretical study, it was shown that a small- to medium-sized power plant with a variance permit could raise river temperatures above the set temperature limit, leading to a larger power plant downstream with no variance permit to reduce its thermal load and suffer a substantial loss in electricity production. However, if both power plants were to comply with regulatory temperature limits, then the total output of the plants could in fact be greater. Indeed, in a follow-up study, Miara et al (2013) simulated Northeastern U.S. river networks and power plant operations (using TP2M) under a set of strategic sensitivity tests. One of these tests demonstrated that the application of regional regulatory temperature limits, with no waivers, targeted at ecosystem protection has a beneficiary effect on some power plants, which are able to operate for more days and with greater efficiency compared to when the regulatory limits were not applied (Figure 2-2) (Miara et al., 2013). However, the aggregate regional output was significantly lower in the summer (Figure 2-3). This highlights the need for planning of the distribution of power plants aligned along individual rivers and regionally across whole river networks, simultaneously taking into account the space and time varying nature of climatic temperature conditions, energy production technology, and CWA temperature limits jointly to maintain a desired standard of ecosystem services and optimal electricity generation.

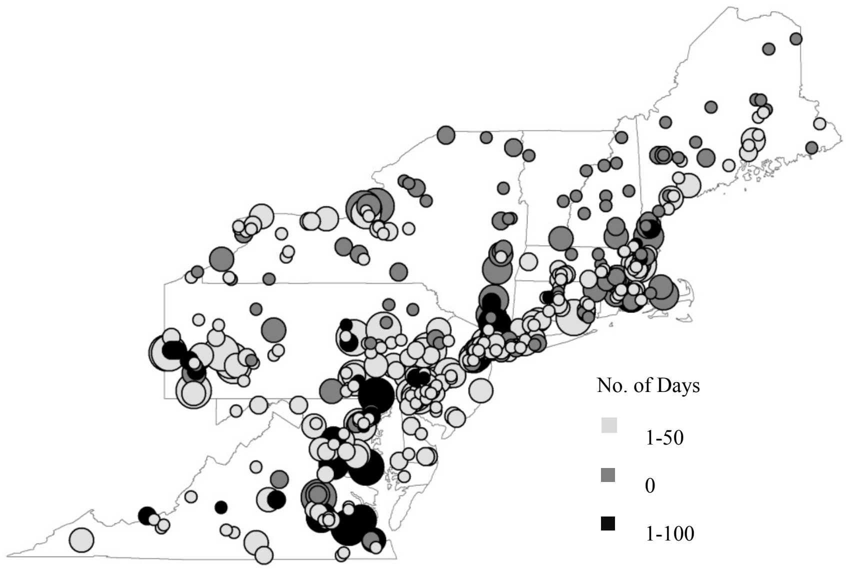

Figure 2-2. The increase in the number of days in the average year (2000-2010) when power plant efficiency is higher (black) or lower (light gray) than 90% of estimated optimal efficiency, relative to a contemporary (2000-2010) simulation as in (Stewart et al., 2013).

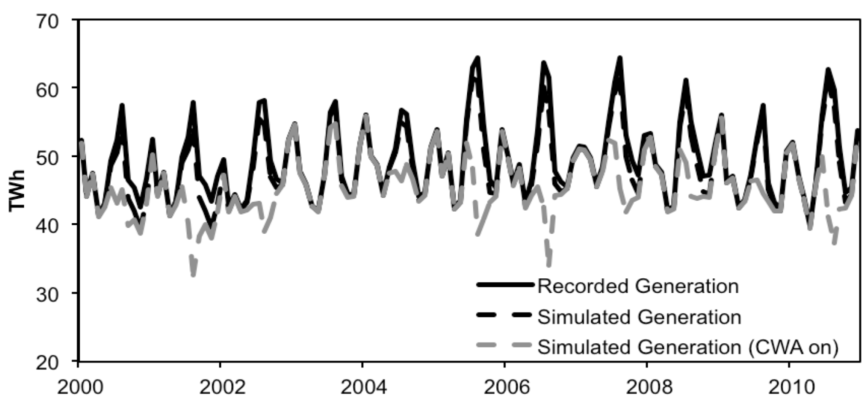

Figure 2-3.Two simulations, contemporary (dashed black) and CWA (dashed gray), of electricity generation for 384 power plants in the Northeastern U.S. that require cooling compared to recorded generation (solid black) for 2000-2010. The CWA simulation can clearly be seen as a constraint on overall regional power production during summertime.

The projected global increase in ambient air temperature is estimated to raise river temperatures and reduce water availability for cooling purposes in the summer (van Vliet et al., 2012). These conditions will increase the susceptibility of power plants to efficiency losses and thermal pollution of receiving waters (Miara et al., 2013). However, there are decisions that can be made today to alleviate some of these potential impacts, such as the installation of alternative cooling technologies and more efficient thermal cycles at power plants.

Alternative technologies such as cooling towers require significantly lower water withdrawal rates compared to once-through systems and eliminate the reliance of power plant efficiency on intake river temperatures (Macknick et al., 2011). Instead, they depend on wet-bulb temperatures to determine the temperature of the cooling water and water is evaporated or cooled before it is discharged back to the river. Thus, power plants with cooling towers are less affected by thermal pollution. They are also low thermal polluters themselves, which keeps water at near ambient temperatures for other downstream users. However, conversion to cooling towers is expensive; wet-cooling towers consume more water than once-through systems (perhaps 40% to 80% more; see Figure 1-5, Chapter 3 in general, and Section 3.6 on forced evaporation) and result in an energy penalty (see Chapter 4; Veil, 2000). Such energy penalties can be extensive if cooling tower conversions are made over a large regional or national scale [as implied in the CWA section 316(b) and discussed in Section 2.2 of this chapter as well as in economics in Chapter 4], to the extent that more power plants would need to be installed and CO_2 emissions would increase should equivalent net generation need to be produced (Veil, 2000).

As discussed in Sections 1.2 and 2.1, the power plant prime mover and fuel mix (for the grid overall or connected via aquatic ecosystems) are just as important factors in determining water use by power plants as environmental regulation and the type of cooling technology itself. Different fuel sources require different withdrawal and consumption rates (Macknick et al., 2011). Therefore, the price of fuel sources, which can be influenced by energy policy and subsidies, plays a central role in water use for cooling and electricity-water trade-offs. In the Northeastern U.S., the expansion of natural gas capacity over the last decade has resulted in an increase in combined-cycle power plants with cooling towers that are more efficient in power production and water use compared to nuclear and coal plants (see Chapter 3) (EIA, 2009; EIA, 2013). This change has helped lower the annual sectoral water withdrawal rate in the region by 5% and simultaneously reduced the impact of thermal pollution (Miara et al., 2013). However, there are life-cycle factors that need to be accounted for, such as fuel extraction methods and the water use required for such processes, in order for a full trade-off assessment to be made.

The importance of accounting for thermal pollution for the siting and installation of new power plants is essential, especially in the context of rising river temperatures and drought (Miara et al., 2013). Thermoelectric power and thermal pollution models with geospatial assessment frameworks now under development on regional and national scales can support coherent energy-water resource planning by capturing the interactive and multidimensional trade-offs that will be necessary in order to realize effective planning. These frameworks will consider alternative engineering cooling technologies and fuel mixes in the context of spatially and temporally varying climate and hydrology, regulatory limits, sensitive aquatic ecosystems, and the economics of electric power generation.

2.4 Energy Information Administration Collection and Dissemination of Cooling System Data

Vlad Dorjets
U.S. Energy Information Administration

2.4.1 EIA and Its Relevant Forms

The U.S. Energy Information Administration (EIA) is the statistical and analytical agency within the U.S. Department of Energy. EIA collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding of energy and its interaction with the economy and the environment. By law, its data, analyses, and forecasts are independent of approval by any other officer or employee of the U.S. Government.

In addition to preparing energy analyses, short-term forecasts, and long-term U.S. and international energy outlooks, EIA conducts a comprehensive data collection program that covers the full spectrum of energy sources, end-uses, and energy flows. The program relies on primary surveys of market participants that are conducted on monthly, quarterly, or annual bases. Data on cooling system characteristics and operations are collected on two such surveys, the "Annual Electric Generator Report" (Form EIA-860)[14] and the "Power Plant Operations Report" (Form EIA-923)[15]. All cooling system data that EIA collects are posted on its website and are available for download and analysis.

The Form EIA-860 is an annual survey of all power plants in the United States that have a combined nameplate capacity of at least 1 MW and where the generator(s), or the facility in which the generator(s) resides, is connected to the local or regional electric power grid and has the ability to draw power from or deliver power to the grid. The survey collects data on the static characteristics such as the type and capacity of its generators, boilers, environmental equipment, and cooling system from plants that are either in operation or planned to begin operation within 10 years. While all plants filling out the form must provide data on their generators, only those plants that have 100 MW or more of combined nameplate capacity must provide data on their boilers and cooling systems.

All operating plants that fill out a Form EIA-860 must also fill out a Form EIA-923, which organizes operating data relating to those generators, environmental equipment and cooling systems. A subset of the plants (based on a stratified statistical sample) must provide certain data on a monthly basis while the remaining plants must provide it on an annual basis. Operating data on environmental equipment and cooling systems are collected annually so those plants that are part of the monthly sample must submit a supplemental form with those data.

2.4.2 Ensuring Accuracy of EIA Data

EIA ensures the accuracy of its data through a series of automated and manual quality assurance mechanisms. First, before a respondent is able to submit a form to EIA, the agency's Internet data collection system (IDC) automatically reviews its proposed form to ensure that key values are not left blank and that values fall within expected ranges, when such ranges are appropriate and available. The IDC also compares

[14] http://www.eia.gov/electricity/data/eia860/index.html
[15] http://www.eia.gov/electricity/data/eia923/

submitted values with values provided elsewhere on the form. Whenever a key value is either left blank or appears too high or low, as appropriate, the respondent is required to either correct it or provide an appropriate explanation. EIA staff reviews all such explanations and determines whether or not they are acceptable or require follow-on communications.

Once all surveys have been submitted during a particular collection cycle, EIA runs a series of internal computer programs that, among other things, compare the submitted data against historical values and values submitted on other surveys. Whenever the programs identify data that appear to violate internal rules, EIA reviews the occurrences and follows up with respondents, as appropriate.

Ultimately, EIA accepts any value submitted on its forms that appears reasonable and passes its automated and manual checks. However, EIA staff constantly review trade publications and external analyses to validate its data. Similarly, users of EIA data routinely provide input on specific elements with which they are familiar. If EIA has credible reason to believe that a value may be incorrect, it contacts the respondent directly with the matter.

2.4.3 Maintaining Relevance of EIA Data

EIA surveys must go through a triennial review and clearance process with the U.S. Office of Management and Budget (OMB). The process not only re-clears the forms for their continued use but also serves as the mechanism by which EIA can modify them; any substantive changes that EIA wants to make to its surveys—whether the change represents the inclusion of a new question, the deletion of an existing question, or a modification of a question—must be announced in the Federal Registrar and be subject to public comment.

Given the increased attention paid to water use by electric power plants in recent years (~ since late 2000s), EIA has placed particular emphasis on ensuring that the cooling system data meet the needs of policymakers, academic researchers, industry analysts, and all other customers. As a result, EIA has made significant improvements to the scope of questions relating to cooling systems and to the accuracy of the data provided by individual respondents.

2.4.4 *Cooling System Data Collected by EIA*

EIA has worked closely with many stakeholders to ensure that Forms EIA-860 and EIA-923 collect the relevant data needed on cooling systems. Form EIA-860 collects the key characteristics of the cooling systems in operation, while Form EIA-923 collects the operating data for those same systems. The Form EIA-860 also collects information on the relationship between the cooling systems, the associated boilers, and the associated generators. Such information can be used to answer questions such as how much coal-fired capacity can be cooled through cooling towers. The cooling system data collected on forms 860 and 923 are listed in Table 2-3 and Table 2-4.

Table 2-3. Cooling-System Data Collected on Form EIA-860 (2010-2012).

Actual or Planned Operating Date of Cooling System	Maximum Cooling Tower Power Requirement
Cooling System Installation Costs	Cooling System Status
Cooling System Type	Cooling Pond Surface Area and Volume
Cooling Water Source	Maximum Cooling Tower Flow Rate
Cooling Water Type	Maximum System Flow Rate
Actual or Planned Operating Date of Chlorine Discharge, Cooling Tower, and Cooling Pond	Cooling Tower Type

Table 2-4. Cooling-System Data Collected on Form EIA-923 (2010-2012).

Total Monthly Amount of Chlorine Added to Water	Maximum Monthly Water Temperatures at Intake and Discharge
Average Monthly Rates for Consumption, Withdrawal, Discharge, and Diversion of the Cooling Water	Average Monthly Water Temperatures at Intake and Discharge
Monthly Cooling System Status	The Methodology Used When Water Flow and/or Temperature Data are Estimated
Hours in Service	

2.5 Nomenclature

fps	Feet per second
gallons/MWh	Gallons per megawatt-hour
GHG	Greenhouse gas
GWh	Gigawatt-hour (10^9 watt-hours)
Hz	Hertz
IWRM	Integrated water resources management
km^2	Square kilometers
km^2/GWh	Square kilometers per gigawatt-hour
m	Meters
m^2	Square meters
MWh	Megawatt-hour (10^6 watt-hours)
NOx	Nitrogen oxides
SO2	Sulfur dioxide
W	Watt
W/m^2	Watts per square meter

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3 Engineering and Physical Modeling of Power Plant Cooling Systems

3.1 Heat and Water Balance of Power Plant Cooling Systems

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Evapco

3.1.1 Introduction to Cooling System Types

In a steam power plant a steam *condenser* is used to condense the exhaust steam from the low-pressure turbine. When the steam condenser uses water as the cooling medium and is designed like a shell-and-tube heat exchanger, it is called a surface condenser. When the steam condenser uses air as the cooling medium and is designed like a radiator, it is called an air-cooled condenser (ACC).

A steam condenser is a large piece of equipment because more than 60% of the thermal energy produced by a steam power plant ends up as low enthalpy waste heat. This waste heat is rejected into the environment. Classical thermodynamics holds that the lower the temperature of the heat sink, the higher the efficiency of the Carnot cycle.[16] Therefore attaining the lowest possible condensing temperature in the steam condenser is a primary goal in steam condenser design. As the quantity and temperature of the cooling water would allow, surface condensers are operated at a level of vacuum typically 35 to 85 millibars absolute (1.0 to 2.5 inches of mercury absolute). In comparison, air-cooled condensers are operated at levels of vacuum that depend on the ambient air temperature, typically 50 millibars absolute in cold climate to 250 millibars absolute in warm climate (1.5 to 7.5 inches of mercury absolute).

3.1.1.1 Psychrometrics or Psychrometry

Psychrometrics is an engineering field that studies the physical and thermodynamic properties of gas-vapor mixtures. The condensing of steam in steam-electric, or thermoelectric, power plants involves a gas-vapor mixture of air and water vapor. In general, the psychrometric properties of a mixture of air-water vapor can be computed by equations and plotted in a chart usually called the Psychrometric Chart. Properties

[16] The efficiency of the ideal Carnot cycle = 1- T_L/T_H, with T_L = temperature of low-temperature heat sink, T_H = high temperature of heat source.

such as density, specific volume, enthalpy, vapor pressure, humidity ratio, wet bulb temperature, dry bulb temperature, dew point temperature, and relative humidity of the air-water mixture are computed and used in thermodynamic calculations leading to the rating and performance predictions of evaporative (wet) cooling towers.

3.1.1.2 Cooling Systems Used With Surface Condensers

Coupled with surface condensers, there are several different ways of using water as the cooling medium:

- *Once-through* uses cold water from a natural body of water and returns warm water to the same natural body.
- Once-through with a helper cooling tower uses cold water from a natural body of water and returns the water to the same natural body, after it has been cooled in a wet-cooling tower to a temperature in agreement with environmental regulations.
- In a closed loop using a *wet-cooling tower* system, the hot water returning from the surface condenser is cooled by direct contact with atmospheric air, mainly by evaporation, and it is pumped back to the surface condenser.
- In a closed loop using a *dry-cooling* system, the cooling water from the surface condenser flows inside heat exchanger tubes. The water is cooled by atmospheric air flowing outside the tubes, mainly by convection and conduction; there is no direct contact between the water to cool and the air. The cooled water is pumped back to the surface condenser.
- Any combination of wet and dry cooling in a closed loop is called hybrid (or wet-dry) cooling.

3.1.2 Once-Through Cooling

In once-through cooling, the steam that flows into the surface condenser from the steam turbine is cooled with water from a natural body of water that flows in an open loop with respect to the power plant infrastructure. As the cooling water flows through the surface condenser, it absorbs the heat from the steam cycle. Typically, the cooling water is withdrawn from a river, lake, or the ocean and discharged into the same water body (see Figure 3-1). Figure 3-1 shows, figuratively, the intake of cold water from a typical river and the discharge of hot water downstream. This design is perhaps the most straightforward for power plant cooling. For the purposes of evaluating the thermal efficiency of the power plant, the cold water temperature, T_L, is that of the water source.

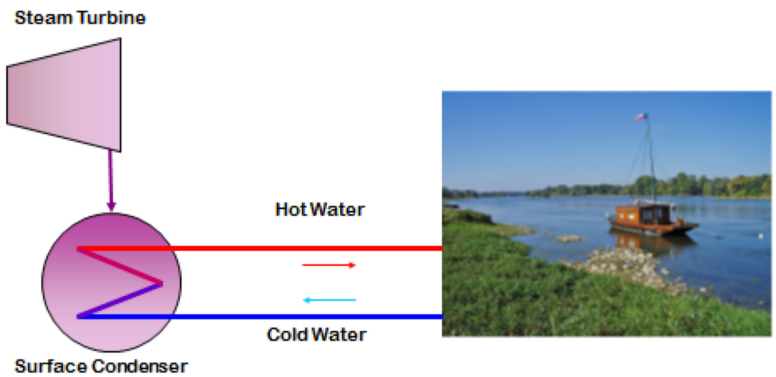

Figure 3-1. Once-through cooling system.

Figure 3-2 is an example of once-through cooling with helper cooling towers. In this case, the mechanical draft cooling towers cool the hot water from the condenser before it goes back to the river.

Figure 3-2: Once-through cooling system with helper cooling towers.

3.1.3 Wet-Cooling Towers

There are two main designs of cooling towers: mechanical draft and natural draft cooling towers. In using wet-cooling towers, the steam from the steam turbine flows into the surface condenser, and the heat in the steam is transferred to the water from the cooling tower. This cooling water flows in a closed loop between the cooling tower and the surface condenser. The functional purpose of the cooling tower is to expose the closed-loop cooling water to air after the water has absorbed the steam cycle heat within the surface condenser. Typically, the cooling water is pumped to an elevation above the cooling tower fill and then it falls by gravity against the flow of air. In the mechanical draft tower cooling air is forced vertically through the tower by large fans driven by electric motors and gear reducers or belt drives (see Figure 3-3).

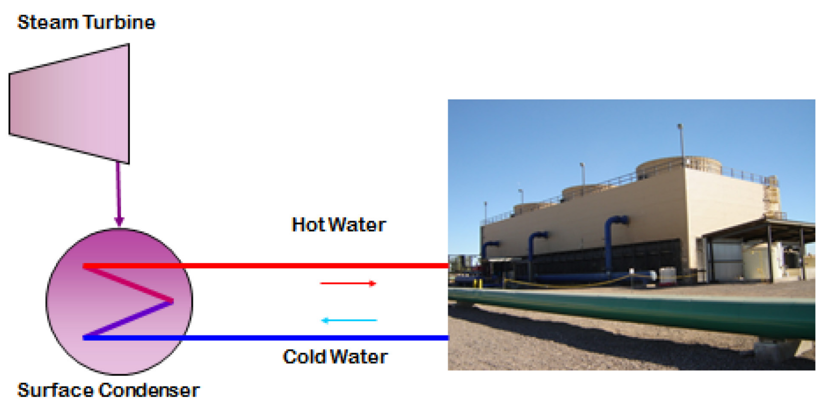

Figure 3-3. Mechanical draft cooling tower in relation to surface condenser of power plant.

In natural draft towers, the hyperbolic shell creates a chimney which forces the cooling air to flow naturally thanks to the difference of density between the heavier cool ambient air and the lighter hot saturated air inside the shell (Figure 3-4 and Figure 3-5).

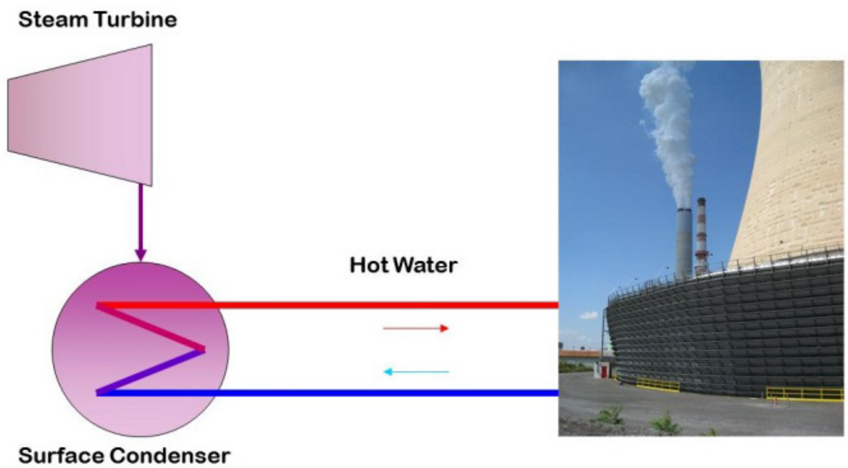

Figure 3-4: Natural draft cooling tower in relation to surface condenser of power plant.

Figure 3-5: Natural draft (hyperbolic) towers.

In evaporative (wet) cooling towers, the hot water flowing from the surface condenser to the cooling tower comes in contact with ambient air; cooling happens mostly by evaporation, which is a mass transfer. Only a small fraction of cooling happens by convection heat transfer.

The temperature of the cold water leaving the cooling tower approaches the air wet bulb temperature.

3.1.4 Heat Balance of a Cooling Tower

This section derives the equations that describe the heat and mass transfer between water and air within an evaporative wet-cooling tower. The hot water from the condenser flows from a network of pipes and low-pressure spray nozzles vertically by gravity over the cooling tower fill. The cooling air flows through the fill either vertically up, in counterflow cooling towers, or horizontally, in crossflow cooling towers. The air cools the warm water mostly by evaporation and leaves the cooling tower saturated or nearly saturated.

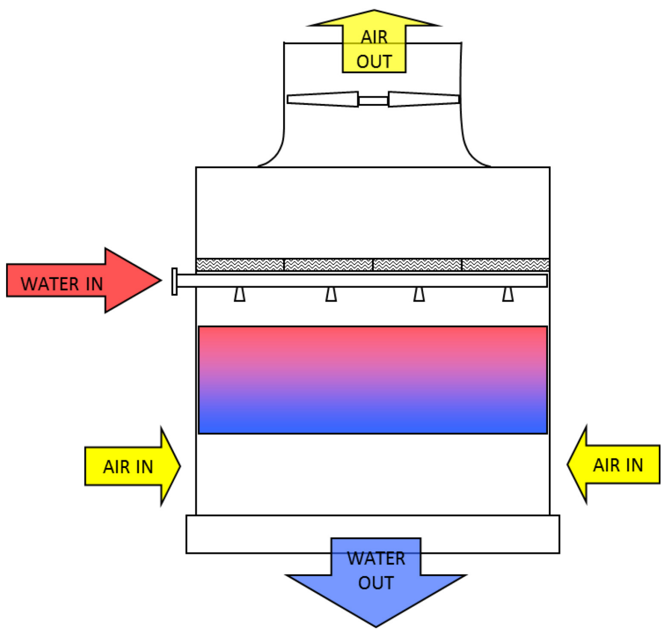

Figure 3-6. Schematic of wet-cooling tower heat balance.

The heat balance is as in Equations Eq. (3-1) and Eq. (3-2):

$$\text{heat}_{in} = \text{heat}_{out} \qquad \text{Eq. (3-1)}$$

$$c_p \dot{m}_{water,1} T_{water,1} + \dot{m}_{air} h_{air,1} = c_p \dot{m}_{water,2} T_{water,2} + \dot{m}_{air} h_{air,2} \qquad \text{Eq. (3-2)}$$

where,

c_p = specific heat of water [J/kg/K or BTU/lb/F]

$\dot{m}_{water,1}$, $\dot{m}_{water,2}$ = mass flows of water entering (subscript 1) and leaving (subscript 2) cooling tower [kg/s or lb/hr]

$T_{water,1}$, $T_{water,2}$ = temperatures of water entering and leaving cooling tower [°C or °F]

$\dot{m}_{air}$ = mass flow of air [kg/s or lb/hr]

$h_{air,1}$, $h_{air,2}$ = enthalpies of air entering and leaving tower [J/kg or BTU/lb]

The difference between $\dot{m}_{water,1}$ and $\dot{m}_{water,2}$ is the evaporation due to mass transfer:

$$\dot{m}_{water,1} - \dot{m}_{water,2} = \dot{m}_{air}\left(w_2 - w_1\right) \qquad \text{Eq. (3-3)}$$

where w_1, w_2 = humidity ratios of moist air entering and leaving tower, respectively [kg moist air/kg dry air or lb m.a./lb d.a.].

Combining Equations Eq. (3-2) and Eq. (3-3):

$$c_p \dot{m}_{water,1}\left(T_{water,1} - T_{water,2}\right) = \dot{m}_{air}\left(h_{air,2} - h_{air,1}\right) - c_p \dot{m}_{air} T_{water,2}\left(w_2 - w_1\right) \qquad \text{Eq. (3-4)}$$

Then:

$$h_{air,2} = h_{air,1} + c_p \frac{\dot{m}_{water,1}}{\dot{m}_{air}}\left(T_{water,1} - T_{water,2}\right) + c_p T_{water,2}\left(w_2 - w_1\right) \qquad \text{Eq. (3-5)}$$

In Equation Eq. (3-5) the properties of the leaving air are unknown. To find $h_{air,2}$ one needs to solve by trial and error. Assuming that the leaving air is saturated, i.e., its relative humidity is 100%, the trial-and-error solution is easy and quick. But to compute the more exact conditions of the leaving air, which can be less than saturated, saturated, or more than saturated (in fogging conditions), one must integrate both on h_{air} and w to solve the equation. The method of integration proposed by Poppe (Kloppers and Kroger, 2005; Poppe and Rögener, 1991) resolves this equation mathematically by carrying out a double integration.

A simple method of calculation of the heat transfer is that proposed by Merkel (Merkel, 1925). In counterflow evaporative cooling, the heat and mass transfer can be applied to a small element of surface at the interface between air and water:

$$dQ = K\left(h_{water} - h_{air}\right)dS \qquad \text{Eq. (3-6)}$$

where

dQ = elemental heat flux [W or BTU/hr]
K = heat transfer coefficient [kg/s/m^2 or lb/hr/ft^2]
dS = elemental heat transfer surface area [m^2 or ft^2]
h_{water} = enthalpy of saturated air at the temperature of the water [J/kg or BTU/lb]
h_{air} = enthalpy of air at the air/water interface [J/kg or BTU/lb]

The heat balance in the element is:

$$dQ = \dot{m}_{air}dh_{air} = c_p\dot{m}_{water,1}dT_{water} + c_p\dot{m}_{air}T_{water,2}dw \qquad \text{Eq. (3-7)}$$

Combining Equations Eq. (3-6) and Eq. (3-7):

$$K\left(h_{water} - h_{air}\right)dS = c_p\dot{m}_{water,1}dT_{water} + c_p\dot{m}_{air}T_{water,2}dw \qquad \text{Eq. (3-8)}$$

Merkel's proposed solution assumes that (1) evaporation is zero (dw = 0), (2) the air leaving the tower is saturated, and (3) the Lewis number relating heat and mass transfer is equal to 1, then integrates over the entire heat transfer surface:

$$KdS = \frac{c_p\dot{m}_{water,1}dT_{water}}{\left(h_{water} - h_{air}\right)} \qquad \text{Eq. (3-9)}$$

$$KS = c_p\dot{m}_{water,1}\int_{T_{water,2}}^{T_{water,1}} \frac{dT_{water}}{h_{water} - h_{air}} \qquad \text{Eq. (3-10)}$$

The symbol S is the total heat transfer surface which comprises more than just the cooling tower fill surface area; it includes all areas such as water droplets in the spray, water droplets below the fill (the rain zone), and the total area of the film of water inside the fill. It is practically impossible to calculate or measure S, so typically it is expressed as $S = aV$, where a is the heat transfer surface per unit volume [m^2/m^3 or ft^2/ft^3] and V is the heat transfer volume or the volume of fill and rain [m^3 or ft^3]. Since the assumption is made by Merkel that the evaporation is zero, then $\dot{m}_{water,1} = \dot{m}_{water}$ such that the mass flow rate of water is constant.

So a more familiar expression of Merkel's integral is:

$$\frac{KaV}{\dot{m}_{water}} = c_p \int_{T_{water,2}}^{T_{water,1}} \frac{dT_{water}}{h_{water} - h_{air}} \qquad \text{Eq. (3-11)}$$

Merkel's integral can be computed using the Chebychev 4-points numerical integration. The left-hand side of Equation Eq. (3-11), a non-dimensional value, is a parameter descriptive of the heat transfer capacity of a given heat transfer media, typically called the fill in evaporative cooling towers.

3.1.5 Water Balance for Wet-Cooling Towers

Equation Eq. (3-3) gives the mass flow of evaporated water, and the unknown value in that equation is w_2, the humidity ratio of the air exiting the cooling tower. To compute the condition of the leaving air, we can use Equation Eq. (3-5) where the properties of the exiting air are unknown. To find $h_{air,2}$ $h_{air,2}$ one must solve by trial and error.

One solution option is to first assume that the exiting air is saturated, i.e., its relative humidity[17] is 100%. For this assumption, the trial-and-error solution is relatively easy and quick. A first estimate of the enthalpy of the air exiting the cooling tower, $h_{air,2}$, can be derived from the simplified heat balance where the evaporation is assumed to be zero

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[17] Relative humidity, ϕ, is related to humidity ratio, w, as $\phi = (wP_a(T))/(0.622P_g(T))$, where $P_a(T)$ and $P_g(T)$ are the vapor pressure and saturated gas pressure at the desired temperature, T.

[i.e., where the term $(w_2 - w_1) = 0$ in Equation Eq. (3-5)], leaving us with the following Equation Eq. (3-12):

$$h_{air,2} = h_{air,1} + c_p \frac{\dot{m}_{water,1}}{\dot{m}_{air}} \left(T_{water,1} - T_{water,2}\right) \qquad \text{Eq. (3-12)}$$

On the right-hand side of Equation Eq. (3-12) all the parameters are known. From $h_{air,2}$, and assuming the relative humidity of the leaving air is 100%, we can determine a value for w_2 and use it in Equation Eq. (3-5) to find a new value of $h_{air,2}$ that can be used to compute a new value of w_2. By continuing this iteration, this calculation converges quickly.

To compensate for the water that evaporates from the wet-cooling tower, it is necessary to add water to the system to keep the volume constant. This added water is the *makeup water*. As water evaporates, the concentration of dissolved solids increases and the water quality changes. To control water quality, it is also necessary to discharge water from the cooling tower to flush out these dissolved solids. This discharge water is called the *blowdown water* or *bleed*. Some of the water is also lost due to drift losses from the cooling tower.

The relationship between these values is:

$$M = E + B + D \qquad \text{Eq. (3-13)}$$

where the water flow rates are M for the makeup, E for the evaporation, B for the blowdown, and D for the drift. The number of cycles of concentration, n_{cc}, is the ratio between makeup and blowdown:

$$n_{cc} = {}^{M}\!/_{B} \qquad \text{Eq. (3-14)}$$

Combining Equations Eq. (3-13) and Eq. (3-14), the makeup flow rate is computed as:

$$M = \frac{n_{cc}}{\left(n_{cc} - 1\right)} \left(E + D\right) \qquad \text{Eq. (3-15)}$$

Consider a typical 500 MWe thermal power plant with an efficiency of 30%. In this case, the total power plant must dissipate 1,177 MW [e.g., 500/(1,177+500) = 0.30], equal to 4,016 million BTU/hr (MMBtu/hr). Table 3-1 shows the input values and results for this example. Note: For simplicity, this example assumes that 100% of the heat of the power plant is dissipated via the condenser through the wet-cooling tower. This assumption is closest to that for a nuclear power plant, but for a coal-fired power plant, approximately 5% to 20% of the power plant waste heat is dissipated via heat in the flue gas and sensible heat from power plant equipment (see Section 0). After an economic optimization of the cooling system, the cooling tower is specified to cool condenser water flowing at 300,000 GPM (18,927 L/s) with a temperature differential, $T_{water,1}$-$T_{water,2}$ = 27°F. The temperature of the water leaves the condenser at 113°F (45°C) and returns from the cooling tower at 86°F (30°C). Assume the power plant is located at sea level in an area where the designed entering air wet bulb temperature is 77°F (25°C) and the air relative humidity is 60%. The cooling tower manufacturer proposes a cooling tower that requires 32,584 lb/s of airflow to meet the cooling requirements.

At design conditions, the evaporation is expected to be 6,900 GPM (435 L/s), or 830 gal/MWh (3,146 L/MWh), and the drift loss 3 GPM (0.2 L/s). Assuming six cycles of concentration, the makeup is computed to be 8,284 GPM (523 L/s), or 994 gal/MWh (3,765 L/MWh).

Table 3-1. Input values and results from the iterative procedure to solve for the evaporation and makeup flow for a wet-cooling tower.

		Imperial units		SI units	
Water	Flow Rate	300,000	GPM	18,927	L/s
	$T_{water,1}$	113	^oF	45	^oC
	$T_{water,2}$	86	^oF	30	^oC
	$\rho_{water,1}$	61.76	lb/ft^3	990.3	kg/m^3
	$\dot{m}_{water,1}$	41,283	lb/s	18,743	kg/s
	$c_{p,water,1}$	1.001	BTU/lb/^oF	4.186	kJ/kg/^oC
	Power dissipated	4,016	MMBTU/hr	1,177	MW
Air	Barometric pressure	29.921	in Hg	1,013.2	mbar
	$T_{air,1}$	88.5	^oF	31.4	^oC
	$T_{air,1}$ (wet bulb)	77	^oF	25	^oC
	RH_1	60	%	60	%
	$\dot{m}_{air}$	32,584	lb/s	14,793	kg/s
	ρ_{air}	0.0716	lb/ft^3	1.1472	kg/m^3
	specific volume	14.21	ft^3/lb dry air	0.8870	m^3/kg dry air
	$h_{air,1}$	40.45	BTU mix/lb dry air	76.26	kJ mix/kg dry air
	Dew point	72.8	^oF	22.7	^oC
	w_1	0.0175	--	0.0175	--
Eq. Eq. (3-12)	$h_{air,2}$	74.68	BTU mix/lb dry air	155.81	kJ mix/kg dry air
	RH_2	100	%	100	%
	w_2	0.0455	--	0.0455	--
Eq. Eq. (3-5) (1st)	$h_{air,2}$	76.20	BTU mix/lb dry air	159.34	kJ mix/kg dry air
	RH2	100	%	100	%
	w_2	0.0467	--	0.0467	--
Eq. Eq. (3-5) (2nd)	$h_{air,2}$	76.26	BTU mix/lb dry air	155.57	kJ mix/kg dry air
	RH_2	100	%	100	%
	w_2	0.0467	--	0.0467	--
Eq.	evaporation	953	lb/s	433	kg/s
Eq.	E	6,923	GPM	437	L/s

(3-13)	E	831	gal/MWh	3,146	L/MWh
	D (drift)	3	--	0.2	--
	n_{cc}	6	--	6	--
	M	8312	GPM	524	L/s
	M	994	gal/MWh	3,765	L/MWh

3.1.6 Wet-Cooling Tower Materials and Design

3.1.6.1 Wet-Cooling Tower Fills

Different types of fills exist for different applications. In wet-cooling towers, the internal heat exchanger packing is generally called the fill. There are two fundamental types of heat transfer surfaces between water and air: air over film of water and air over droplets of water.

Film fills apply the principle of air over film of water. They are typically assembled in packs made from thin corrugated sheets of polyvinyl chloride (PVC) plastic formed under heat and vacuum; the formed packs have repetitive flutes and a microstructure to enhance the area of contact between the thin film of water and the cooling air. The flutes and the microstructure mix water and air; their geometry is designed to raise the heat transfer while keeping the air-side pressure drop low.

Splash fills apply the principle of air over droplets. They are typically extruded from high-density polypropylene, polyethylene, or PVC compounds to form bars. The bars are installed horizontally using grids or wires that support their ends. The formed bars have shapes designed to enhance their ability to span a good distance without excessive deformation. They are perforated to break the water in fine droplets to increase the area of heat transfer.

Film fills are typically used in counterflow cooling towers where the cooling air flows vertically up against the falling water. Splash fills are typically used in crossflow cooling towers where the cooling air flows horizontally to come in contact with the falling water droplets. Some factory-assembled or small field-erected cooling towers use film fill in crossflow applications. Splash fills can be used in counterflow, too, for example in seawater applications or to cool waters laden with a high concentration of suspended solids.

Cooling tower fills can be put in four broad categories:

1. Cross flutes: The flutes in the thermoformed sheets are angled and the angle of the flutes alternates between neighboring sheets, so in effect the flutes are crisscrossing in a pack.
2. Vertical offset flutes: The flutes are oriented vertically but include repetitive changes of direction to redirect both the water and air flows in zigzag.
3. Vertical flutes: The flutes are oriented vertically without change of direction.
4. Splash fills: The falling water is constantly breaking up in droplets.

The heat transfer capacity of these fills is the highest in cross flute fills and decreases toward the splash fills. On the other hand, the tendency of a fill to get fouled or clogged in waters laden with suspended solids follows the opposite trend, being the lowest in splash fills and the highest in cross flute fills. Fill fouling generally reduces the heat transfer capacity of cooling tower fills.

3.1.6.2 Hybrid Fills

Some fills combine the features of film fill and splash fill by using corrugated sheets assembled together in packs, but where the assembled sheets are open like a mesh made of narrow strands. The water hitting the strands is constantly broken up into fine droplets. Such fills are commonly referred to as splash pack or trickle pack.

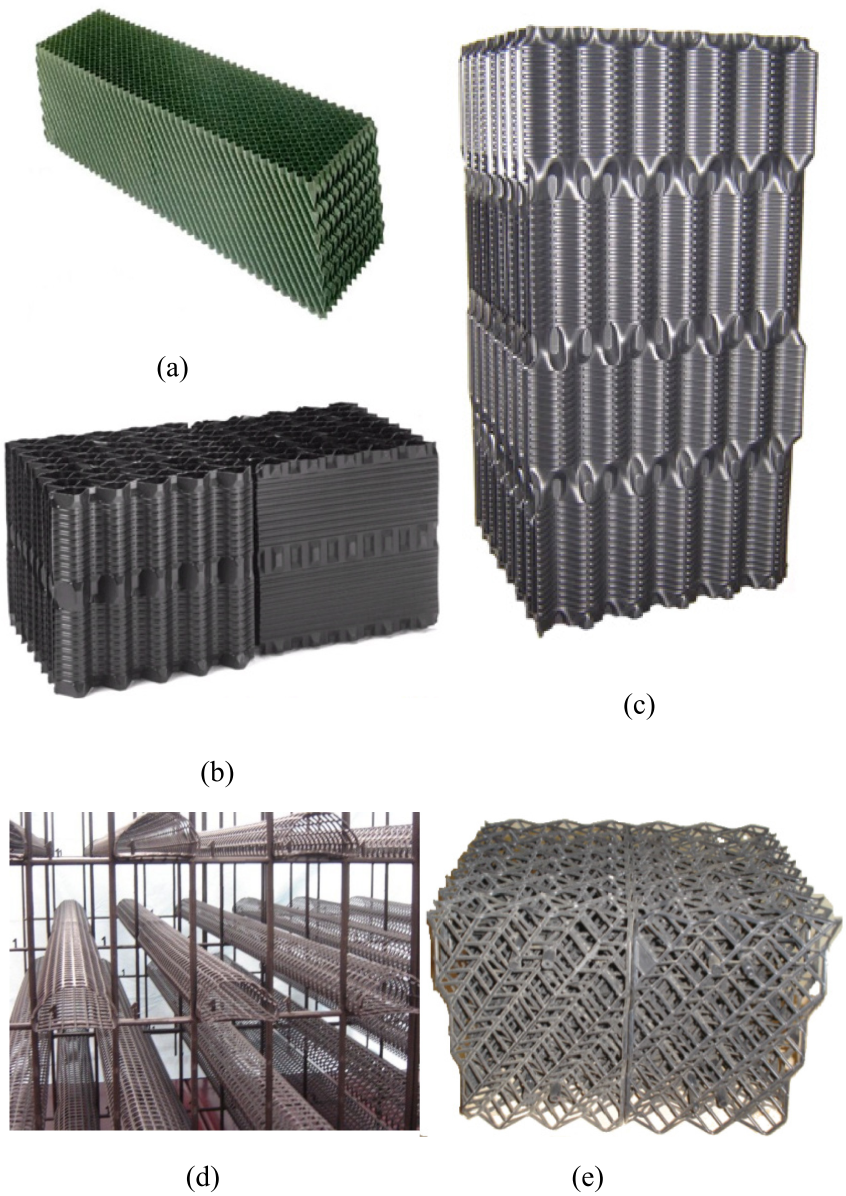


Figure 3-7. Wet-cooling tower fills: (a) cross flutes, (b) vertical flutes, (c) vertical offset flutes, (d) splash bars (crossflow), and splash pack or trickle pack.

3.1.6.3 Drift Eliminators

When the cooling air comes in contact with the water to be cooled, a large number of droplets are carried away in the air stream: these droplets are called *drift* droplets. Drift droplets can potentially be discharged into the atmosphere surrounding the cooling towers. Drift droplets have the same water chemistry as the circulating water but condensation droplets are made of pure water that ultimately constitute the visible plume of a cooling tower.

Drift emissions from cooling towers are tied to power plant particulate emissions, which are regulated by the Environmental Protection Agency. In the current state-of-the-art technology, drift eliminators are designed for use in counterflow and crossflow cooling towers to reduce drift emissions to levels as low as 0.0005% of the circulating water flow in volume. Drift rates can be measured by methods described in codes and standards such as the Cooling Technology Institute (CTI) code ATC-140 Isokinetic Drift Test Code (Libert and Nevins, 2011).

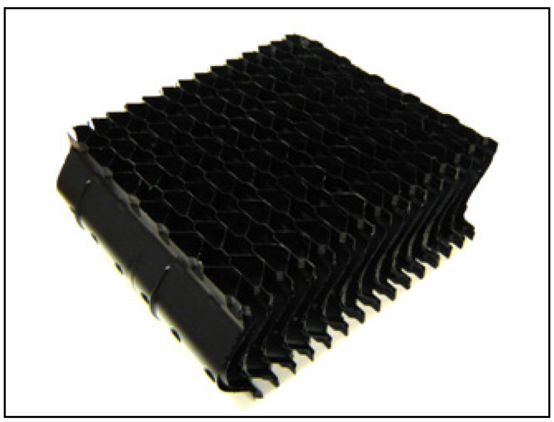


Figure 3-8. Drift eliminator pack.

Drift eliminators, like film fills, are typically assembled in packs made from thin corrugated sheets of PVC plastic formed under heat and vacuum; the formed packs have flutes shaped with sharp changes of direction to capture by inertia the water droplets entrained in the air stream. The captured droplets drain back into the fill below.

3.1.6.4 Mechanical Equipment

In mechanical draft towers, cooling air is forced through the tower by large fans driven by electric motors and gear reducers or belt drives. In large field erected cooling towers, axial fans are mounted inside a venturi-shaped fan stack installed on the top deck of the tower. Axial fans can be as large as 40 feet (12,192 mm) in diameter and be driven by electric motors up to 300 HP (225 kW). Typically a double-stage right-angle gear reducer is used between the motor and the fan to lower the rotation speed from 1,800 RPM (nominal) to around 100 to 300 RPM so that the fan blade tip speed does not exceed the industry-accepted limit of 12,000 FPM (61 m/s). In factory-assembled units, the axial fans can be as large as 14 feet (4,267 mm) in diameter and driven by up to 125 HP motors using either gear reducers or belt drives. Some factory-assembled units use axial fans or centrifugal fans in a forced draft configuration, typically in the smaller fan diameters and motor powers.

3.1.6.5 Cooling Tower Performance

Wet-cooling towers cool the water mostly by evaporation. The temperature of the cold water approaches the air wet bulb temperature. In mechanical draft towers, the volumetric airflow produced by the fan remains practically constant at all temperatures year-round, but in natural draft towers the airflow increases as the air temperature decreases. The graph below shows a comparison between a mechanical draft tower (solid line) and a natural draft tower (dashed line) performance in a 500 MW power plant. The X-axis has the air wet bulb temperature (WBT) and the Y-axis the cold water temperature (CWT) from the cooling tower to the condenser, considering a cooling tower cooling 320,000 gallons per minute of water (20,190 liters/second) with an 18^{o}F (10^{o}C) temperature difference between the hot water temperature from the condenser and the cold water temperature to the condenser. At higher air temperatures, the mechanical draft tower provides a colder CWT than the natural draft tower, and thus is more efficient, but at the lower air temperatures, the natural draft tower performance is more efficient than that of the mechanical draft.

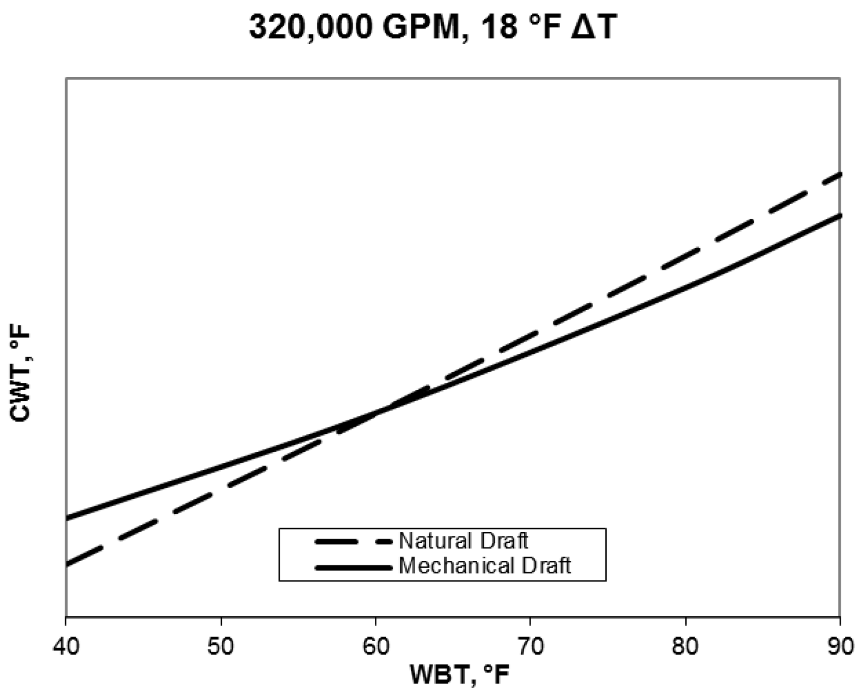


Figure 3-9: Comparison of natural draft vs. mechanical draft cooling tower performance. CWT = cold water temperature, WBT = wet bulb temperature.

3.1.7 Dry-Cooling Towers

3.1.7.1 Indirect Dry Cooling With a Surface Condenser

In dry cooling the steam in the surface condenser condenses with the help of cold water from a dry cooler. The dry cooler contains finned tube heat exchangers. Water from the condenser flows inside the tubes and is returned to the condenser after cooling. Tubes can be round or elliptical, generally arranged in multiple rows. Fins can be rolled or embedded on the outside surface of individual tubes or made in plates that are perforated to allow multiple tubes to be squeezed through them. The cooling air is forced through the cooler by large fans driven by electric motors and gear reducers or belt drives (mechanical draft) or, in rare instances, e.g., in large power plants at ESKOM in South Africa, the air circulation is created by natural draft in hyperbolic shells (natural draft indirect cooling).

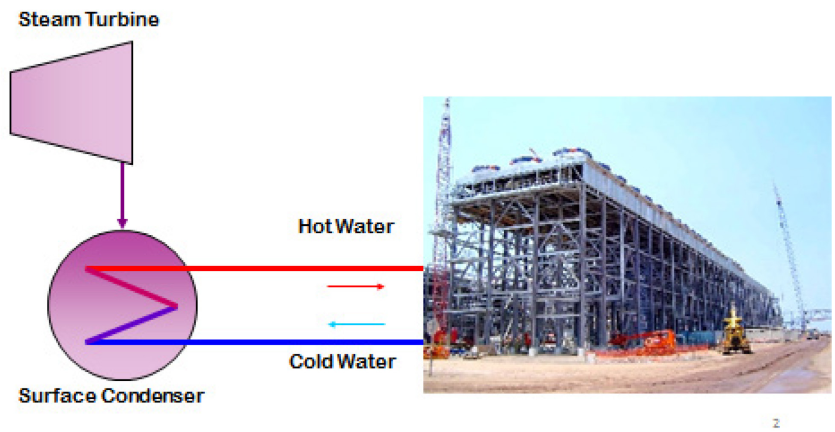


Figure 3-10. Forced draft dry cooling.

In dry-cooling systems, the cooling of the water from the condenser happens by convection heat transfer. The temperature of the cold water leaving the dry cooler approaches the air dry bulb temperature, which is generally greater than the wet bulb temperature. As a consequence, a dry cooler is in general less efficient than a wet-cooling tower.

Wet-cooling systems, being more efficient than dry-cooling systems, produce a lower turbine backpressure so the turbine operates more efficiently, but wet-cooling systems consume water by evaporation, blowdown and makeup; dry-ooling systems do not consume water.

3.1.7.2 Air-Cooled Steam Condensers

Power plants that incorporate Air-Cooled Steam Condensers (ACC) offer significant water savings over power plants using traditional evaporative cooling technologies. State-of-the-art ACCs feature single-row finned tubes installed in an A-frame steel structure. The steam from the turbine exhaust condenses as it is directly cooled by forced convection of the ambient air.

Air-cooled condensers reduce water consumption in combined cycle power plants by more than 97% when compared with traditional, recirculating wet cooling. They also eliminate the environmental impacts of plume, drift, and blowdown associated with wet cooling. Power plants with lower water withdrawal or consumption (e.g., dry cooling) and environmental impact can enable faster permitting than plants with higher water withdrawal or consumption (e.g., wet cooling).

ACCs are now present in many countries with over 200 GWe of generation capacity, and the number of new installations with ACC is growing rapidly.

Figure 3-11. Typical air-cooled condenser installation.

Figure 3-11 illustrates a typical air-cooled condenser installation. Each design can vary somewhat between suppliers or users of the technology. The ACC heat exchangers are configured in an A-frame arrangement. Low-energy de-superheated steam from the steam turbine exhaust or from the steam turbine bypass dump tube enters the first stage heat exchangers through the steam distribution manifold. Axial flow fans mounted at the base of the A-frame force cooling air through the fins of the heat exchangers. The steam condenses as heat is transferred from the steam to the air moving across the fins outside the tubes.

The condensate drains from the heat exchangers into a collection manifold that flows into the condensate tank. A pump transfers the condensate from the tank to the boiler system.

Note that in Figure 3-12 many of the heat exchangers have arrows indicating flow from top to bottom. These heat exchangers represent first stage or primary condenser bundles. The steam enters the top of these bundles and the condensate leaves the bottom. The first stage configuration is thermally efficient; however, it does not provide a means for removing non-condensable gases.

To sweep the non-condensable gases through the first stage bundles, a fraction of the heat exchangers are configured as second stage or secondary bundles, which draw vapor from the lower condensate manifold. In this arrangement steam and non-condensable gases travel through the first stage bundles as they are drawn into the bottom of the secondary bundle. As the mixture of gases travels up through the secondary bundle, more of the steam condenses, concentrating the non-condensable gases. The top of the heat exchangers is attached to a vacuum manifold, which removes the non-condensable gases from the system.

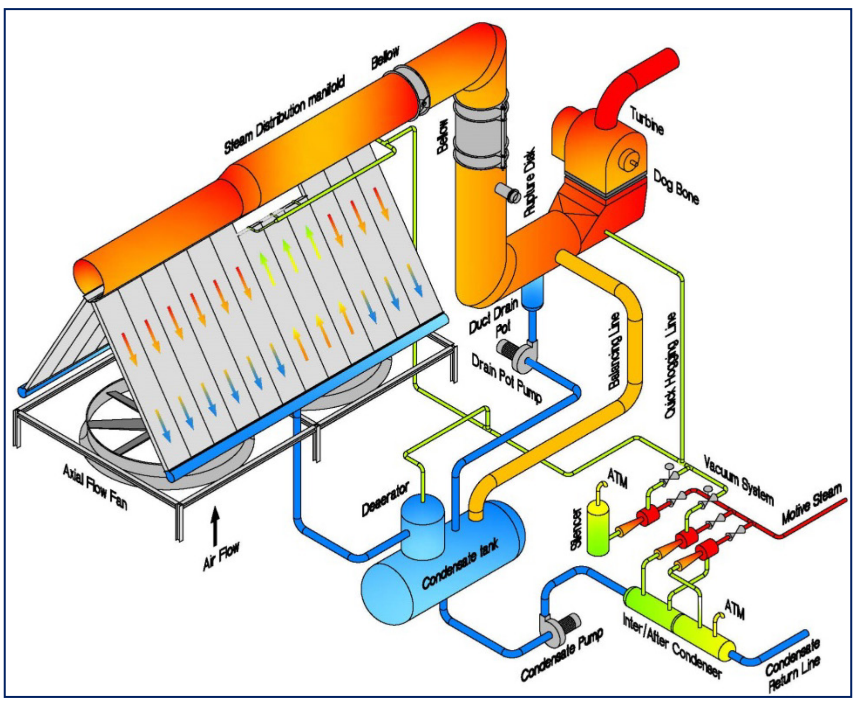


Figure 3-12: Schematic of a typical ACC installation.

At the steam turbine exhaust, the steam enters the ACC system through a large diameter steam *turbine exhaust duct* (TED). The steam turbine bypass dump tube also discharges into the TED. Vertical risers branch off from the TED to *steam distribution manifolds* (SDMs), which distribute the steam into heat exchangers.

To accommodate thermal expansion, expansion joints are provided in the steam duct system. Expansion joints are provided at the turbine exhaust connection, in the risers (lateral type with tie rods), and in the SDMs (hinged type).

For protection reasons, the steam duct is typically equipped with pressure and temperature instruments, rupture discs, and vacuum breakers.

The saturated steam entering the ACC system is not usually 100% dry. The wet fraction of the steam is collected by gravity into a small tank attached to the bottom of the TED called the duct drain pot. The condensate is routed from the duct drain pot to the main condensate tank. For protection and control reasons, the *duct drain pump system* is typically equipped with pressure and level instrumentation.

Steam from the SDMs enters the top of the *primary heat exchangers*, while ambient air flows across the finned outside surface of these heat exchangers, effectively cooling the steam and taking out the latent heat. Approximately 80% of the total steam flow is condensed in the first stage heat exchangers. The flow pattern of steam and condensate in the first stage heat exchangers is co-current and downward. The condensed steam flow and the remaining steam flow are collected at the bottom of the primary heat exchangers in the *condensate collecting manifolds* (CCM). The remaining steam is routed through the CCMs to the *second stage heat exchangers*, entering at the bottom. With ambient air flowing on the outside of the second stage heat exchanges, the latent heat is also taken out of the remaining steam. The flow pattern of the steam and condensate in the secondary heat exchangers is countercurrent: steam goes up and condensate flows down.

The condensate discharging from the bottom of the secondary heat exchangers mixes in the CCMs with the condensate from primary heat exchangers and is routed by gravity to the condensate collection tank.

The presence of non-condensable gases inside the heat exchangers adversely affects their heat transfer performance, so non-condensable gases need to be continuously removed from the system. The optimal location to remove the non-condensable gases is at the top of the secondary heat exchangers, since this is the location with the lowest absolute pressure in the heat exchangers.

The *hogging vacuum equipment* is used to create the vacuum in the ACC at start-up, by removing the air out of the system from atmospheric pressure to the specified hogging pressure. Once the hogging pressure is reached, operation is switched to the holding vacuum equipment, which is continuously in operation when the ACC is in operation.

The airflow across the finned outside surface of the heat exchangers is created by a forced draft arrangement, one fan per module consisting of a large axial flow fan, driven by an electric motor with speed reducing gearbox. For protection reasons, the *air moving equipment* is provided with vibration and oil pressure instrumentation.

Condensate from the heat exchangers and from the duct drain pot is collected in the *condensate tank*. Before entering the condensate tank, the condensate passes through a de-aerator to achieve the required oxygen content limitation. An ejector evacuates all non-condensable gases and excess vent steam from the de-aerator. For control purposes, the condensate tank is provided with level instrumentation.

A high-pressure *cleaning system*, utilizing clean service water, is generally provided to reduce fouling on the cooling fins on the outside of the heat exchangers. The cleaning system consists of:

- Positive displacement high-pressure pump skid located at ground level.
- Rigid piping system from the pump skid to the heat exchanger access walkways on the ACC structure.
- Flexible hoses from the heat exchanger access walkways to the cleaning manifold rigs.
- Permanently installed cleaning manifold rigs on each heat exchanger surface area, which can be moved manually along the complete street length, each on its own rail system.

All high-energy steam flows exceeding the design parameters of the heat exchangers can be routed through a *flash tank* located at the side of the TED, where they are mixed with condensate spray supplied from the main condensate pumps. The vent of the flash tank discharges to the main TED and the drain of the flash tank feeds by gravity to the duct drain pot or is pumped directly to the condensate tank.

3.1.8 Parallel Condensing Systems

The *parallel condensing system* (PCS) is a technology that combines an air-cooled steam condenser in parallel with a surface condenser coupled to a wet-cooling tower, developed primarily to save water (see Figure 3-13). When the ambient air temperatures are warm, the back pressure in the surface condenser is lower than in the ACC because the cold water temperature from the wet-cooling tower is colder than the air dry bulb temperature at the ACC: naturally more steam condenses in the surface condenser than in the ACC. On the other hand, when ambient air temperatures are cold, the backpressure in the ACC approaches that of the surface condenser, so naturally more steam condenses in the ACC than in the surface condenser. By reducing the heat load on the wet-cooling tower, less water is evaporated, which reduces the overall consumption of water.

Practically, the ACC section of the system can be designed to reject the total heat load at low ambient air temperature to meet the specified turbine backpressure. At high ambient air temperature, the wet-cooling tower and surface condenser can be sized to reject all or part of the heat load to meet the specified turbine backpressure while not exceeding a specified quantity of makeup water consistent with local regulations.

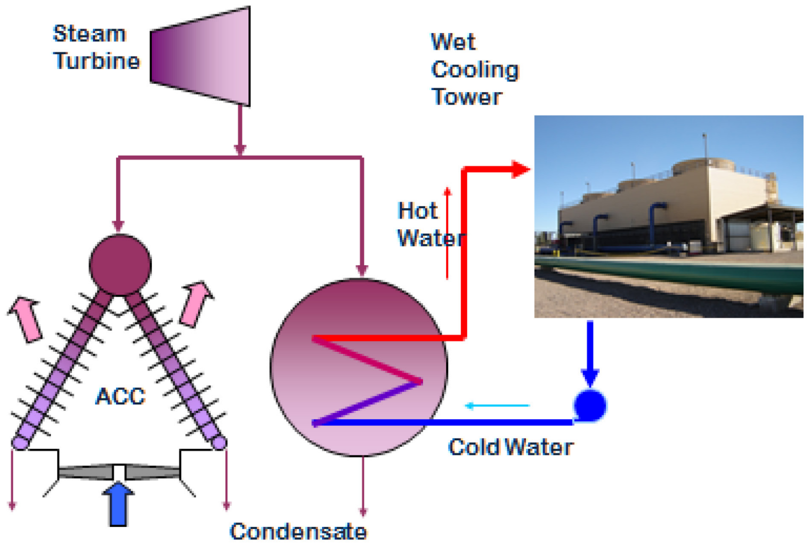


Figure 3-13: Schematic of a parallel condensing system.

According to De Backer and Wurtz, a PCS system is a synergy of established cooling system technologies and combines some positive features of dry and wet-cooling systems; the water consumption is reduced compared to a 100 % wet system, the performance is improved compared to a 100 % dry system, and the capital cost decreases as the proportion of wet in the PCS system is increased (De Backer and Wurtz, 2003).

3.1.9 Hybrid (Wet-Dry) Cooling Towers

Hybrid or wet-dry cooling is a system that combines wet evaporative cooling with dry convective cooling. Wet-dry technologies are used to conserve water and to abate the visible plume from wet-cooling towers. There are a number of different types of wet-dry cooling systems, for example:

- Parallel path wet-dry (PPWD) with wet fill and finned tube heat exchangers, designed primarily for plume abatement. The wet, evaporative section is located in the lower part of the cooling tower. The plenum chamber above the wet section is extended upward to leave room for heating coils along the sides of the tower. Hot water from the condenser goes to the heating coils first, then on to the wet section next. Sometimes the water flow going to the heating coils is a fraction of the overall flow rate. Air dampers are often installed in front of the heating coils. In the summer mode of operation, the air dampers are closed so the cooling air goes through the wet section. In the no-plume mode of operation, the air dampers are open. Some cooling air goes through the wet section while another stream of cooling air goes in parallel through the dry section. The air coming from the wet section is normally warm and saturated with moisture, while the air going through the dry section is hot and dry. When both streams of air mix in the plenum, the overall relative humidity of the exhaust air is lowered below saturation and the plume remains invisible. The heat load dissipated in the heat exchangers reduces the heat load over the wet section in this manner, lowering the quantity of water evaporated.

- <u>Parallel path wet-dry with wet fill and air-to-air heat exchangers</u> is similar in purpose to the PPWD described above, except that it uses air-to-air heat exchangers in the plenum above the wet fill instead of finned tubes. Ambient air is drawn through the air-to-air heat exchangers; it cools the hot saturated air from the wet section by convection. Some of the moisture from the hot saturated air is condensed and recovered in the wet fill in that way, lowering the quantity of water evaporated.

- <u>Series path wet-dry</u> is another way to abate the plume, more typically in packaged towers, by heating the wet exhaust air with heating coils located above the drift eliminators or above the fans. The amount of heat required to heat the wet exhaust air enough to abate the plume is greater than in the case of a PPWD system. Typically very hot water or steam is used inside the heating coils to heat the air.

- <u>Spray-enhanced dry-cooling technology</u>, also called closed-circuit coolers: the water from the condenser flows inside tubes while the cooling air flows outside the tubes. There is no direct contact between the water to be cooled and the cooling air. Another source of water is sprayed over the outside surface of the tubes to lower the tube wall temperature toward the air wet bulb temperature.

- <u>Dry cooling with evaporative air pre-cooler</u>: ambient air is cooled through evaporative pre-coolers by adiabatic cooling, before flowing outside the tubes inside which the water from the condenser flows.

Hybrid systems combine wet- and dry-cooling technologies primarily to combine the advantages of both technologies, which are:

(a) to keep the better performance of wet cooling during the hot summer months, and
(b) to conserve water and water treatment chemicals during the cold winter months by operating in dry mode.

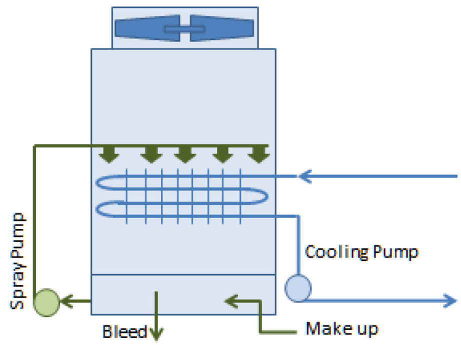
In addition to water conservation, wet-dry systems provide plume abatement. The air temperature at which the system switches over from wet operation to dry operation is called the switch-over temperature. The wet-dry system can be optimized to enable the switch from wet to dry at the highest possible switch-over temperature to save as much water as possible.

3.1.9.1 Spray-Enhanced Closed-Circuit Coolers

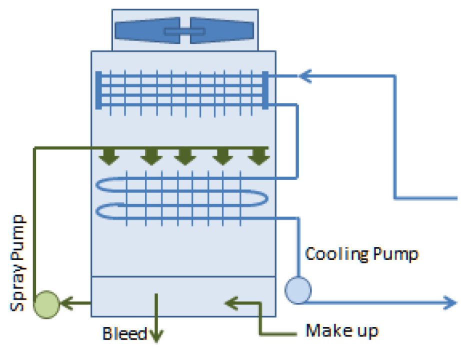
In closed circuit coolers, the water to be cooled flows inside tube coils in a closed circuit between the process heat exchangers or the condenser, so it is never exposed to air. The outside of the tubes is sprayed with water from another source to lower the tube wall temperature toward the air wet bulb temperature to increase the efficiency of cooling. Tubes can be round or elliptical, and can be bare or have fins to increase heat transfer area.

The chemistry of the spray water must be controlled all the time but the volume of treated water is small. The chemistry of the cooling water inside the closed circuit is controlled once at start-up.

The two images in Figure 3-14 show schematics of closed circuit coolers: Figure 3-14(a) with a sprayed (wet) coil, and Figure 3-14(b) with a dry coil in the plenum and a sprayed (wet) coil below. In wet-dry operation, hot water is first cooled through the dry coil and further cooled through the coil sprayed with treated water. In dry operation, the spray system is off so the cooler uses no water and no water treatment chemicals. In addition, the wet-dry cooler has a limited visible plume in wet-dry operation and no visible plume in dry mode.



(a)



(b)

Figure 3-14: Wet-dry closed circuit coolers: (a) with a sprayed (wet) coil and (b) with a dry coil in the plenum and a sprayed (wet) coil below.

3.1.10 Wind Impacts on Dry-Cooling Towers

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The influence of wind on the degradation of ACC performance has long been recognized (Duvenhage and Kröger, 1996; EPRI, 2005; Goldschagg et al., 1997; Van Rooyen and Kröger, 2007) as one of the major design and selection challenges. Figure 3-15 displays the turbine exhaust pressure vs. ambient temperature for a range of wind speeds for full load operation over several months. The exhaust pressure at no, or light, wind is consistently lower (indicating superior ACC performance) than it is at the higher wind speeds. At wind speeds above 20 mph (9 m/s) and ambient temperatures above 100°F (38°C), the turbine exhaust pressure exceeds the no-wind levels by over 1.5 in Hga (50 millibars).

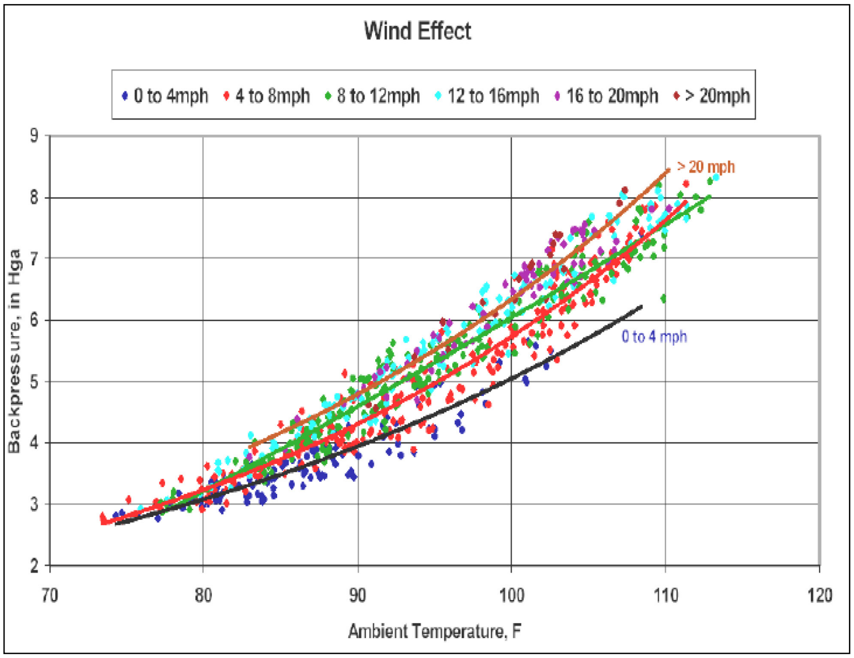

Figure 3-15. Effect of wind speed on ACC performance.

ACC performance is affected both by hot air recirculation, in which a portion of the hot air leaving the unit is re-entrained into the inlet air stream, and by fan performance degradation. Fan performance degradation results from the distortion of flow profiles and static pressure distributions by cross winds passing under the fan inlets. Fan performance degradation is usually the more important mechanism. Reductions in airflow can exceed 60% to 70% of the average flow through the fans, particularly those fans on the upwind edge of the ACC during high wind conditions (Maulbetsch et al., 2011).

Approaches to mitigating the deleterious effect of wind include the provision of extra capacity in comparison to the typical design levels established at low wind conditions such as additional cells or higher fan power. The more usual approach has been the use of windscreens or wind barriers to modify airflow patterns under and around the ACC. A typical example of a porous windscreen installed in a cruciform arrangement under an ACC is shown in Figure 3-16. A comprehensive study of windscreen behavior, effect on performance, and design recommendations was initiated by the California Energy Commission in 2012.

Figure 3-16. Porous windscreen under an ACC.

3.2 Summary of S-GEM: System-Level Generic Model of Thermal Cooling Systems

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[+] The findings, interpretations, and conclusions expressed in this chapter do not necessarily reflect the views of the executive directors of the World Bank or the governments they represent.

The system-level generic model (S-GEM) of power plant water use (Rutberg et al., 2011) is a broadly applicable analytical model that outputs water withdrawal and consumption intensity of wet-cooling systems. It was developed to capture the essential physics of the processes involved while minimizing computational complexity and number of input parameters. The basis of input parameters was selected such that each parameter has a clear physical meaning that can be related to plant operating conditions and performance metrics, ideally those that are specified for large numbers of plants in readily available data sets. The S-GEM is suitable for vetting field data, or synthesizing data where field data is unavailable, as when evaluating hypothetical scenarios. It additionally serves as a common quantitative framework for evaluating the effects of various technologies on power plant water use. The S-GEM applies to fossil, nuclear, geothermal, and solar thermal plants, using either steam or combined cycles.

Because cooling dominates water withdrawal and consumption in most plants, the S-GEM focuses on cooling system water withdrawal and consumption, leaving the non-cooling process water use intensity as a stand-alone term, I_{proc} [L/MWh]. To determine the heat load on the cooling system, and thus the cooling system water use, the S-GEM considers a simplified power plant heat balance (see Figure 3-17):

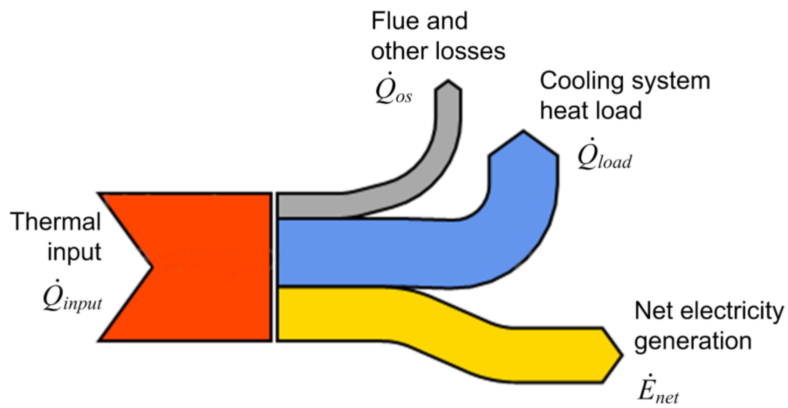


Figure 3-17: Heat flow through a generic steam-cycle or combined-cycle power plant.

Referencing the diagram, the net efficiency η_{net} can be defined:

$$\eta_{net} \equiv \frac{\dot{E}_{net}}{\dot{Q}_{input}} \qquad \text{Eq. (3-16)}$$

where $\dot{E}_{net}$ [MW] is the net electricity generation rate and $\dot{Q}_{input}$ [MW] is the rate of thermal input to the plant. The value of η_{net} is typically known on a plant-by-plant basis, since it is a key performance metric.

The dimensionless coefficient k_{os}, representing the fraction of heat lost to sinks other than the cooling system, is defined as:

$$k_{os} \equiv \frac{\dot{Q}_{os}}{\dot{Q}_{input}} \qquad \text{Eq. (3-17)}$$

where $\dot{Q}_{os}$ [MW] is the rate of thermal loss up the flue and to other sinks.

The heat loss mechanisms encompassed by $\dot{Q}_{os}$ include heat rejected directly into the atmosphere (not counting any such heat transfer in the cooling system) and heat lost due to a difference in enthalpies of the input and output streams (net of any difference in enthalpies of formation that is accounted for by the heating value of the fuel in $\dot{Q}_{input}$). The value of k_{os} is plant-specific and is not typically known, but it is reasonably consistent within each generation technology.

The cooling system heat load per output MWh can be expressed as a simple function of two parameters, k_{os} and η_{net}. For a given heat load, the amount of cooling water withdrawn or consumed depends on the cooling system. The two most common at U.S. power plants are wet tower and once-through cooling systems (Feeley III et al., 2008), each with very different mechanisms of water use.

For a once-through-cooled plant, withdrawal intensity I_{wo} [L/MWh] depends strongly on the temperature rise across the condenser, ΔT_{cond} [K]; the overall S-GEM expression is:

$$I_{wo} = 3600 \frac{(1 - \eta_{net} - k_{os})}{\eta_{net}} \frac{1}{\rho_w c_{p,w} \Delta T_{cond}} + I_{proc} \qquad \text{Eq. (3-18)}$$

where ρ_w [kg/L] and $c_{p,w}$ [MJ/kg-K] are the density and specific heat of water. The mechanism for water consumption in once-through cooling systems is increased evaporation, or forced evaporation, due to the higher temperature of the discharged water. The expression for once-through consumption intensity I_{co} [L/MWh] is:

$$I_{co} = 3600 \frac{(1 - \eta_{net} - k_{os})}{\eta_{net}} \frac{k_{de}}{\rho_w c_{p,w} \Delta T_{cond}} + I_{proc} \qquad \text{Eq. (3-19)}$$

where the "downstream evaporation" coefficient k_{de} is the fraction of discharged water that undergoes forced evaporation as a result of having been warmed, typically on the order of 1% (consistent with a ΔT_{cond} near 10 ^{o}C) (Myhre, 2002). For a given set of ambient conditions, the ratio $k_{de}/\Delta T_{cond}$ is approximately constant, meaning that heat and mass transfer theory can be used to predict once-through consumption (Diehl, 2012; Stolzenbach, 1971) even if ΔT_{cond} is not known.

In a wet tower-cooled plant, there are several cooling water loss mechanisms, of which evaporation from the cooling tower is the most significant. The blowdown purged from the cooling water circuit to avoid buildup of harmful contaminants is another; it may be evaporated in holding ponds (in which case it is consumed) and/or discharged to the watershed (in which case it is not counted as consumed). A third water loss mechanism is drift, spray that leaves the tower as liquid, but S-GEM considers this negligible (Maulbetsch, 2004).

A wet-cooling tower rejects heat through both *latent* and *sensible heat* transfer. Latent heat transfer is associated with the mass transfer of evaporated water, while sensible heat transfer refers to direct convection of heat from the water to the air. The fraction of heat load rejected through sensible heat transfer is denoted here as k_{sens}, and depends on the temperature of the incoming air, and to a lesser extent on the design of the cooling tower and the ambient humidity and atmospheric pressure. Its value may be calculated using cooling tower heat and mass balance models, zero-dimensional (Leung and Moore, 1970), or somewhat more accurately, one-dimensional (Kloppers and Kroger, 2005). The remaining heat load, rejected through latent heat transfer, determines the amount of water evaporated from the tower.

The rate of blowdown can be related to the rate of evaporation in terms of the number of cycles of concentration, n_{cc}, a parameter that describes the concentration of impurities in the circulating water relative to that of the makeup water. The purer the input stream, the more cycles of concentration can be tolerated before mineral impurities reach unacceptable levels; typical values for n_{cc} in the U.S. are between 2 and 10 (Klett et al., 2007; Myhre, 2002).

The resulting expression for withdrawal intensity I_{ww} [L/MWh], for a plant with a wet-cooling tower, is:

$$I_{ww} = 3600 \frac{(1-\eta_{net}-k_{os})}{\eta_{net}} \frac{(1-k_{sens})}{\rho_w h_{fg}} \left(1+\frac{1}{n_{cc}-1}\right) + I_{proc} \qquad \text{Eq. (3-20)}$$

where h_{fg} [MJ/kg] is the latent heat of evaporation of water. The delta between withdrawal and consumption for a wet tower-cooled plant hinges on how blowdown is dispatched. At one extreme is zero liquid discharge (ZLD), where none of the blowdown is discharged back to the watershed, in which case withdrawal and consumption are identical. If some fraction of the blowdown, k_{bd}, is treated and discharged, however, the S-GEM equation for consumption intensity I_{cw} [L/MWh] becomes:

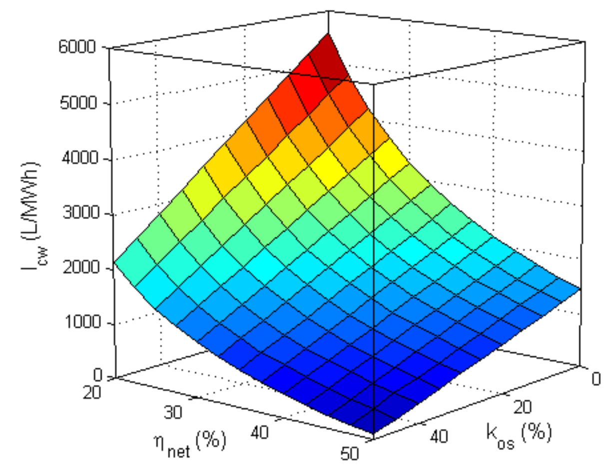
$$I_{cw} = 3600 \frac{(1-\eta_{net}-k_{os})}{\eta_{net}} \frac{(1-k_{sens})}{\rho_w h_{fg}} \left(1+\frac{1-k_{bd}}{n_{cc}-1}\right) + I_{proc} \qquad \text{Eq. (3-21)}$$

The values of the blowdown terms n_{cc} and k_{bd} are often unavailable on a plant-by-plant basis, but they follow regional trends. In the U.S., plants in arid regions tend to run high n_{cc} and low k_{bd}, while plants in wetter regions run low n_{cc} and high k_{bd}.

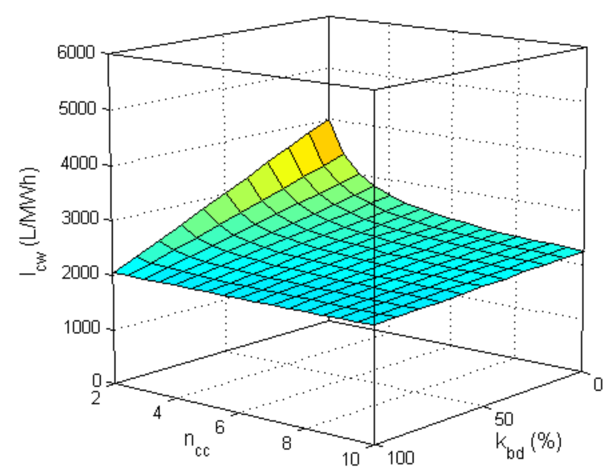
For most plants with once-through or wet tower-cooling systems, non-cooling process uses, such as boiler feedwater makeup, cleaning, ash handling, and flue gas desulfurization, account for less than 10% of the overall water withdrawal or consumption intensity. The term I_{proc}, which encompasses these uses, is accounted net of any internal recycling streams; a non-cooling process whose wastewater was then used as makeup water for the cooling system would not count toward I_{proc}. Similarly, a non-cooling process whose water source consisted of cooling tower blowdown would not count toward I_{proc}. For the purposes of the S-GEM, I_{proc} is considered the same for both withdrawal and consumption; it is assumed that any non-cooling process wastewater streams discharged to the watershed, as opposed to evaporated or recycled, are negligible. The value of I_{proc} is plant-specific, but can be estimated to some extent based on the types of processes used at the plant.

3.2.1 Sensitivity of S-GEM

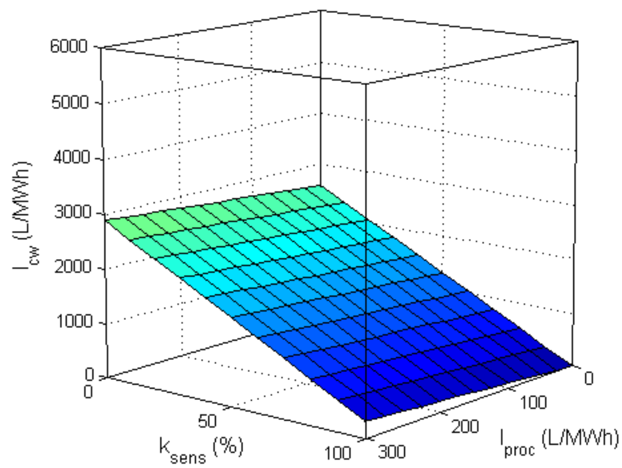
More broadly, S-GEM serves as a consistent, quantitative framework to examine the levers that control power plant water use, thus illuminating the most effective means of reducing water consumption. Figure 3-18 shows the sensitivity of water consumption intensity I_{cw} to various pairs of S-GEM parameters, all other parameters remaining constant at baseline values typical for a wet tower-cooled coal plant (η_{net} = 34%, k_{os} = 12%, k_{sens} = 15.5%, n_{cc} = 10, k_{bd} = 0%, I_{proc} = 75 L/MWh).


6000
5000
4000
3000
2000
1000
0
I_{cw} (L/MWh)
20
30
40
50
η_{net} (%)
0
20
40
k_{os} (%)

(a)


6000
5000
4000
3000
2000
1000
0
I_{cw} (L/MWh)
2
4
6
8
10
n_{cc}
0
50
100
k_{bd} (%)

(b)



(c)

Figure 3-18: Bivariate sensitivity of water consumption intensity I_{cw} to (a) heat balance parameters η_{net} and k_{os}; (b) blowdown parameters n_{cc} and k_{bd}; and (c) parameters k_{sens} and I_{proc}.

As Figure 3-18(a) shows, the heat balance parameters are very strong levers with respect to water consumption. A wet-cooled binary geothermal plant with η_{net} = 10% and k_{os} = 0% consumes vastly more water than a combined-cycle gas plant with η_{net} = 50% and k_{os} = 20%. Differences in net efficiency in fact explain much of the variation in water use between plants, both within and across generation technologies. Improving the efficiency of a power plant, e.g., by reblading an aging turbine, will result in commensurate reduction in water intensity. Furthermore, topping-cycle cogeneration plants, in which waste heat is sent out for district or process heating, can achieve very high values of k_{os}. Where there is sufficient demand, cogeneration can greatly reduce the load on the cooling system and thus the amount of cooling water required.

The effect of wet tower blowdown parameters n_{cc} and k_{bd} is illustrated in Figure 3-18(b). Treating the cooling makeup water to enable increased values of n_{cc} can decrease blowdown, but this has somewhat limited scope for reducing water consumption. As discussed above, plants running at low values of n_{cc} often discharge most of their cooling tower blowdown to the watershed. Plants already running at high values of n_{cc} can obtain only incremental water savings by pushing it the value even higher.

Figure 3-18(c) shows the significance of k_{sens}, the fraction of heat rejected through sensible heat transfer. For wet tower-cooled systems, k_{sens} falls within a fairly narrow range, typically 0% to 30%. The effect on water consumption is fairly weak and mostly beyond the control of the tower designer (see Section 3.2.2). However, changing the cooling technology altogether can have dramatic effects on k_{sens} and thus on water consumption. Once-through cooling systems effectively have substantially higher values of k_{sens} relative to cooling towers, on the order of 30% to 70% (see Section 3.2.3), while hybrid wet-/dry-cooling systems can have still higher values. In the limiting case of a completely dry-cooled plant, all waste heat is rejected through sensible heat transfer; k_{sens} is equal to 100% and the only remaining water use is for non-cooling processes.

The above sensitivity analyses reveal that of the possible means of reducing water consumption at power plants, many yield only incremental results. Tuning a wet tower-cooled plant for efficiency, implementing blowdown and process water recycling schemes, and using dry flue gas desulfurization (FGD) and ash handling all result in reduced water consumption, but on the order of perhaps 5% to 20% collectively. To achieve water consumption reductions of a factor of two or more, there are essentially only three options: switch to a much more thermally efficient generation technology, implement topping-cycle cogeneration, or use a different type of cooling system.

3.2.2 Effects of Ambient Conditions: Once-Through Cooling

A sensitivity analysis of k_{lat} (fraction of heat load dissipated through latent heat transfer, i.e., evaporation, defined as 1-k_{sens}) to water temperature, wind speed, and elevation was conducted using a heat and mass balance treatment of once-through cooling systems given by Stolzenbach (Stolzenbach, 1971), as shown in Figure 3-19. While elevation is a weak effect, both water temperature and wind speed are very strong determinants of k_{lat}; water consumption can easily vary by a factor of two or more depending on ambient conditions. It is also worth emphasizing that for large water bodies, k_{lat} does not depend at all on the temperature rise across the condenser, the incident radiation, or the temperature and humidity of the ambient air (Stolzenbach, 1971).

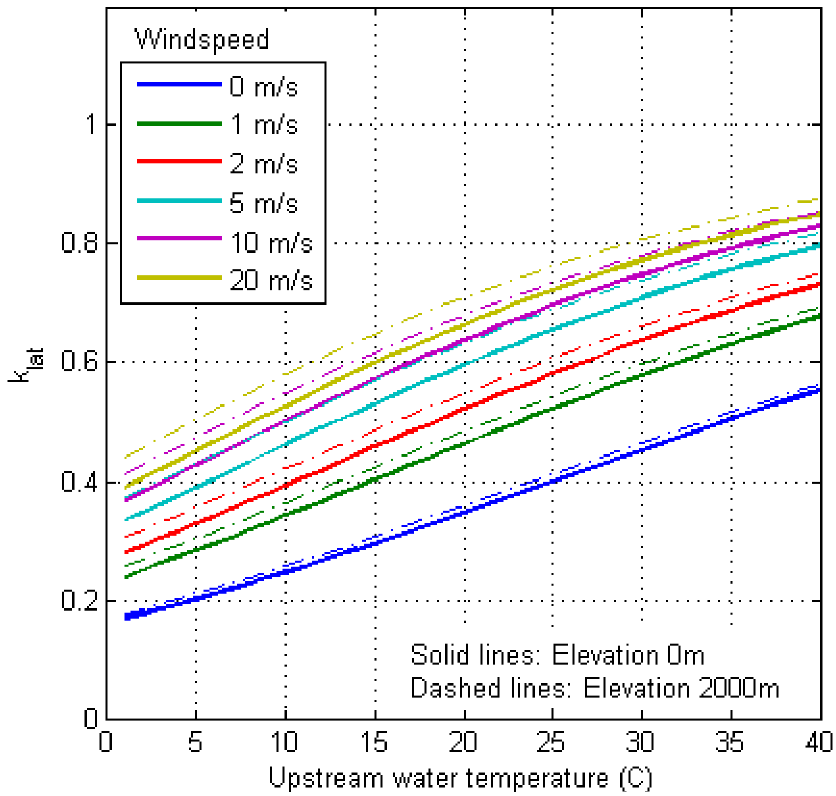


Figure 3-19: Sensitivity of k_{lat} to water temperature, wind speed, and elevation.

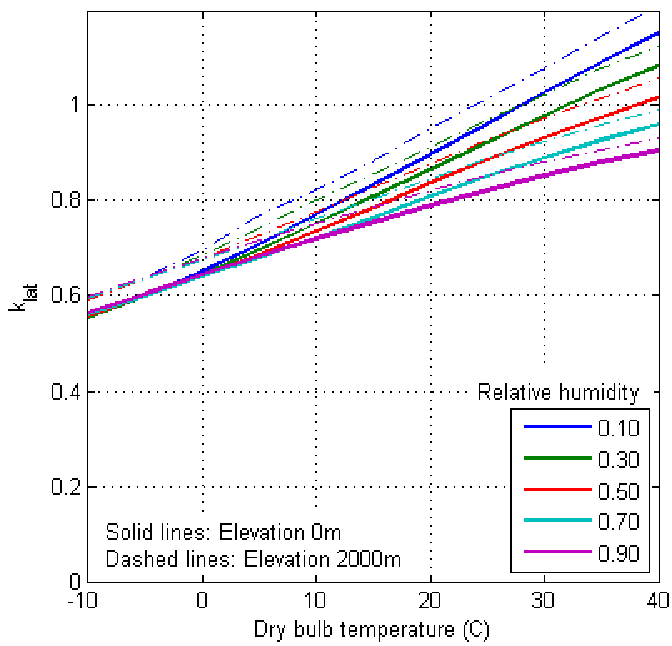
3.2.3 Effects of Ambient Conditions: Wet-Cooling Tower

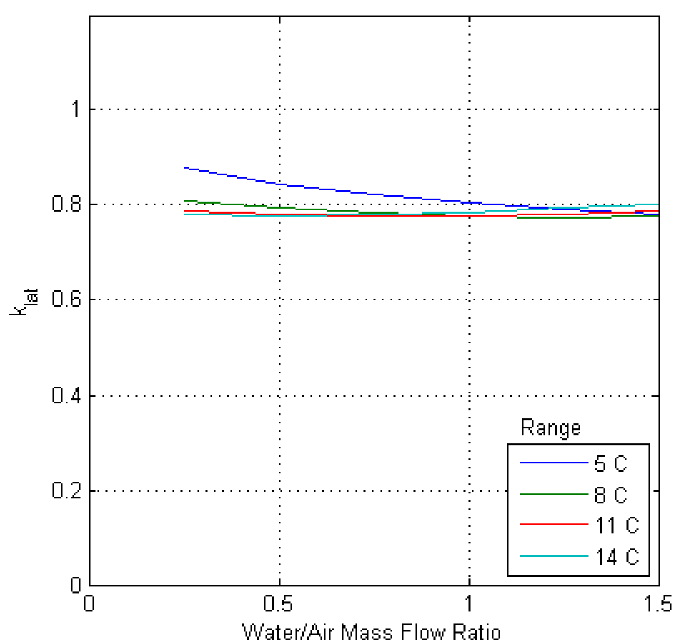
The sensitivity of k_{lat} to ambient temperature, humidity, and elevation for a wet-cooling tower as predicted by the Poppe model (Kloppers and Kroger, 2005) was examined, as shown in Figure 3-20(a). Temperature is the strongest determinant followed by humidity and finally elevation. In this analysis, all tower design parameters were held constant at typical values: the tower inlet water/air mass flow ratio within the tower was 0.8; the inlet/outlet water temperature difference (cooling range) was 11°C; and the Merkel number (a dimensionless parameter corresponding to relative tower size) was 1.5. For description of Merkel number, see (Kloppers and Kroger, 2005).

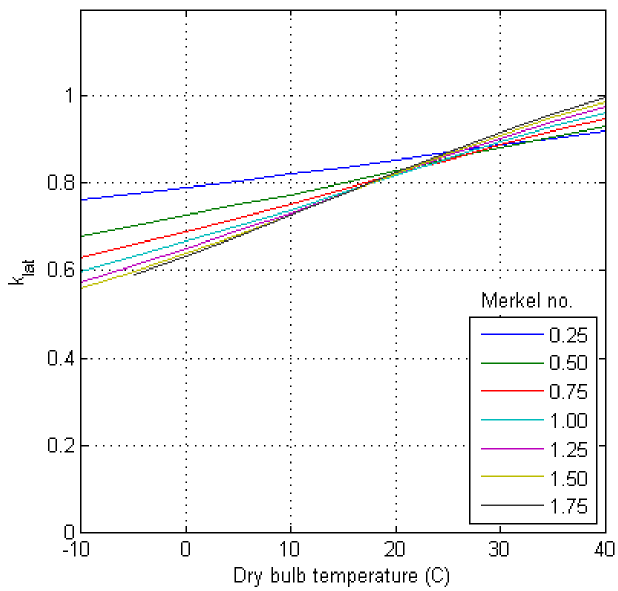
A second sensitivity analysis [Figure 3-20(b)] was performed of k_{lat} to cooling range and inlet water/air mass flow ratio, assuming 15°C ambient dry bulb temperature, 0.6 relative humidity, 0 m elevation, and a

Merkel number of 1.5. The effects of these parameters are clearly secondary.

A third sensitivity analysis [Figure 3-20(c)] was performed varying Merkel number and inlet dry bulb temperature, holding the other parameters constant at the same baseline values as above. While increasing tower size reduces k_{lat} at lower air temperatures, it actually increases k_{lat} at high air temperatures. This makes some physical sense; since warm air can hold so much more water than cool air, making the tower increasingly larger in a warm environment means increasingly more water evaporating into the warm air. Since most water-scarce places are hot as opposed to cool, and since increasing tower size linearly yields diminishing increases in k_{sens} even at cooler air temperatures, it seems unlikely that sizing a tower larger than optimal for cooling performance and cost would ever result in an overall reduction in water consumption substantial enough to warrant doing so.


k_lat
Relative humidity
0.10
0.30
0.50
0.70
0.90
Solid lines: Elevation 0m
Dashed lines: Elevation 2000m
Dry bulb temperature (C)
(a)


k_lat
Range
5 C
8 C
11 C
14 C
Water/Air Mass Flow Ratio
(b)



(c)

Figure 3-20: Sensitivity of k_{lat} to various parameters according to the Poppe cooling tower model: (a) Ambient temperature, humidity and elevation; (b) Cooling range and water/air mass flow ratio; (c) Ambient temperature and Merkel number (relative tower size).

3.3 Cooling of Natural Gas Combustion and Combined Cycle Power Plants

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Combined cycle power plants use the Brayton cycle as the topping cycle (gas turbine) and the Rankine Cycle (steam turbine) as the bottoming cycle. This is the most widely used configuration of combined cycle power plant used in the power industry. The plants are generally powered by natural gas, although fuel oil, synthesis gas, or other fuels can be used. Natural gas combustion combined cycle power plants need fresh water consumption for inlet air cooling processes, NOx control, power augmentation, and cooling tower operation.

3.3.1 Inlet Air Cooling in Gas Turbines

Inlet air cooling increases the power output of a gas turbine by cooling down the compressor (of the gas turbine) inlet air temperature to near ambient wet bulb temperature. As shown in Figure 3-21 (Steward, 1998), decreasing inlet air temperature (increasing air density) enables higher mass flow rate into the gas turbine that causes enhanced turbine output and efficiency. In the case of a single GE LM 6000 PC gas turbine (45 MW), water consumption is estimated at 13 gallon per min (or 17 gallon/MWh = 13 gpm × 6-min/hr/45 MW) with the intercooler, which annually consumes 50,500 gallon per MW (= 17.3gallon/MWh × 8hrs/day × 365 days) based on 8 hours operation per day (General Electric, 2008a; General Electric, 2008b).

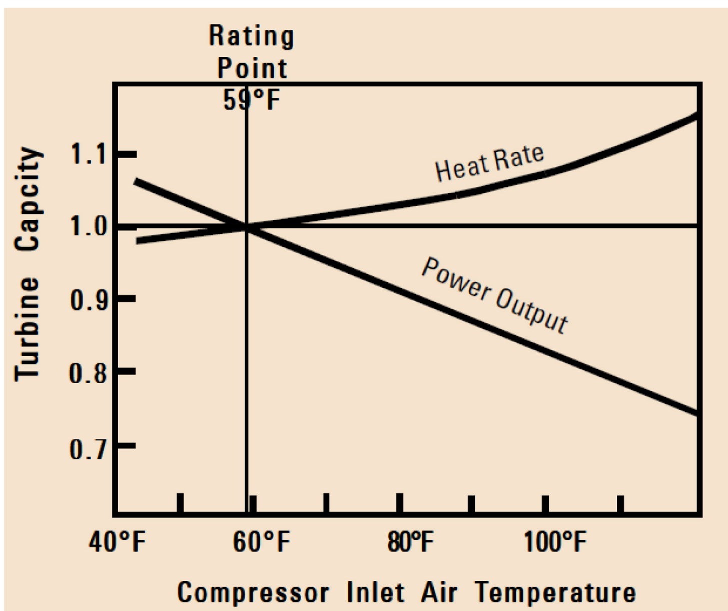

Figure 3-21. Turbine output vs. inlet air temperature [1].

3.3.2 Water for DeNOx System in Gas Turbines

NOx emissions can be reduced by injecting water into the combustor of the gas turbine. Fuel moisturizing is frequently used to reduce NOx emissions. These methods can reduce the NOx emissions to 20 ppm[18] in volume at dry basis. In case of a single GE LE 6000 PC gas turbine (45

[18] ppm = parts per million

MW), water for NOx control is injected at 40 gpm[19] (or 53 gallon/MWh = 40 gpm × 60 min/yr / 45 MW) that equals 156,000 gal/MW-yr (= 53 gal/MWh × 8 hr/day × 365 day/yr) annually, assuming 8 hours operation per day.

3.3.3 Natural Gas Combined Cycle Cooling Requirements

Consider a natural gas combined cycle power plant comprising two gas turbines and one steam turbine with a total capacity of 135 MW: 2 units of 45 MW gas turbine and 1 unit of 45 MW steam turbine. The steam turbine cycle runs with a closed steam loop at 50 kg/s that is cooled by water flowing at 150 kg/s (2,373 gpm) in a cooling tower. The cooling tower consumes fresh water at 37.5 kg/s (495 gpm, 220 gal/MWh = 495 gpm × 60 min/hr / 135 MW from 135 MW) to make up for evaporation and drift loss (25%) in a wet-cooling tower. At 100% capacity factor the annual consumption of fresh water for the steam turbine cycle amounts to approximately 2 million gallon per MW of capacity (= 220 gal/MWh × 24 hr/day × 365 days/yr).

The fresh water consumption rate in a combined cycle (~ 220 + 53 = 273 gal/MWh) is up to four times greater than a single gas turbine (~ 17 + 53 = 70 gal/MWh) due to the cooling load requirement for the steam cycle. The single gas turbine has generally no cooling load even though the combustion gas exhausts at very high temperature around 400°C (750°F).

Table 3-2. Natural gas combined cycle power plant water consumption needs, assuming a wet-cooling tower and a 2:1 ratio for gas turbine to steam turbine.

Component	Consumption for NGCC (gal/MWh)
NG combustion turbine intercooler	6 – 12
NG combustion turbine DeNOx system	18 – 53
Cooling tower for combined cycle (2 gas turbine × 1 steam turbine)	90 – 220
TOTAL	110 – 290

[19] gpm = gallons per minute

3.4 Extraction of Water From Power Plant Exhaust Gas

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One possibility for recovering water in power plants is to separate and condense water vapor from the boiler exhaust, or flue, gas to reduce overall plant water consumption. Flue gas exhausted from a boiler or gas turbine is a potential water source for a power plant. For example, for a 600 MW pulverized coal-fired power plant the flue gas typically contains 6% to 16% water vapor (360,000 to 960,000 lb/hr), which corresponds to approximately 72 to 192 gal/MWh (Jeong, 2009; Jeong et al., 2010; Jeong and Levy, 2012; Levy et al., 2011; Levy et al., 2008). Flue gas moisture can be phase-changed into liquid water and separated from flue gas by using condensation technology. The U.S. DOE has been supporting technology development for condensing water from fossil power plant flue gas by using condensing heat exchangers (NETL, 2006b) and transport membrane condensers (NETL, 2009).

3.4.1 Condensing Heat Exchanger

The purpose of a condensing heat exchanger is to convert water vapors into liquid phase through film condensation on the coolant tubes in the heat exchanger. A condensing heat exchanger system can be installed after the flue gas treatment system in a power plant. At this location, the flue gas flows into the shell at 120^{o}C to 200^{o}C and cooling water of 15^{o}C to 37^{o}C flows within the condensing tubes. Film condensation of flue gas water vapor occurs on the tube surfaces as the surface temperature cools down below the dew point of water vapor in flue gas. The condensed water is separated by density difference and collected at the bottom of the heat exchanger where it can be recycled into appropriate water supplies: feed water, makeup water for cooling tower, or any other application. Prior to this water reuse, the condensed water usually needs further treatment such as filtration, acid removal, and/or demineralization.

3.4.2 Flue-Gas Water Recovery Calculation—NGCC Example

A case study with a water recovery system using condensing heat exchanger, as shown in Figure 3-22, has been performed for a natural gas combined cycle power plant that includes two 45 MW natural gas turbines and one 45 MW steam turbine. The proposed system is installed after the heat recovery steam generator routes flue gas from both gas turbines (226 kg/s) into the water recovery system. Assuming 10 wt%

(14 vol%) moisture content and 50% condensation efficiency[20], 11.3 kg/s of liquid water can be recovered as condensate out of 22.6 kg/s of moisture in flue gas. As shown in Figure 3-23, the two gas turbine cycle requires 2 kg/s for the intercooler and 6 kg/s for the De-NOx system, which can be covered by regenerated water. The remaining 3.3 kg/s of water can be recirculated for cooling tower makeup.

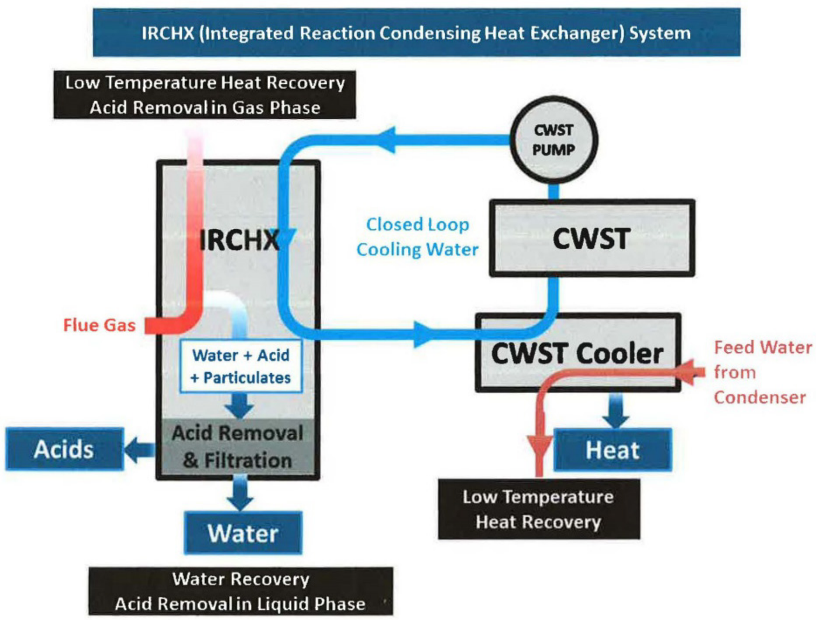

Figure 3-22. Flue gas water recovery system (Jeong, 2012).

By applying the water recovery system for the 135 MW natural gas combined cycle system, with a 2:1 ratio of gas to steam turbine as described in Section 3.3:

- Annual water recovery for the gas turbine part of the combined cycle power plant is 700,000 gal/MW of capacity
  - = 11.3 kg/s / 1,000m^3/kg × 264.2 gal/m^3 × 3600 s/hr × 24 hrs/day × 365 days/yr / 135 MW

[20] Here, condensation efficiency is defined as mass ratio of recovered water to moisture vapor in boiler flue gas. It can recover 50 wt% of water vapor into liquid phase in case of 50% condensation efficiency.

- Assuming a water cost of \$0.03/100 gallon, a power plant operator could realize an annual savings of 210 \$/MW of capacity.

The complete economic justification for the water recovery depends on combustion conditions, operational hours and dispatch, climate, and other factors. If the 135 MW combined cycle power plant runs at 100% capacity factor with the water recovery system, it could save up to 94 million gallons per year.

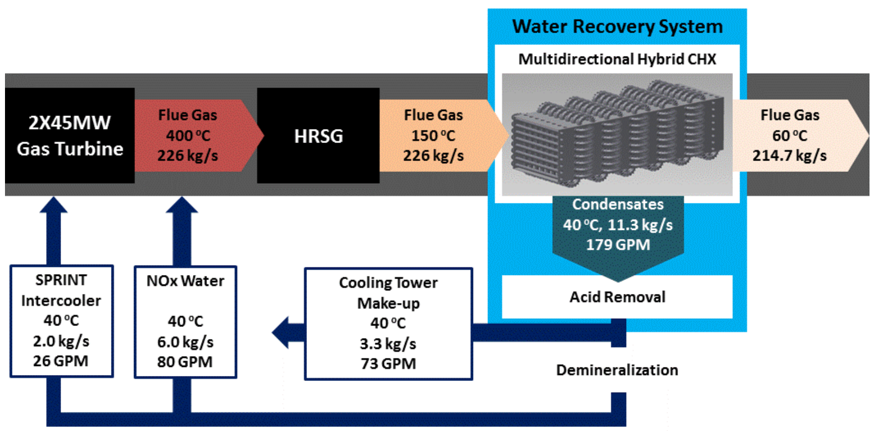

Figure 3-23. Water recovery system for a natural gas combined cycle power plant.

3.4.3 Flue-Gas Water Recovery Calculation—Coal Example

Here, consider a flue-gas water recovery system applied to a 600 MW coal-fired power plant with 10 wt% moisture in the boiler flue gas and a flue gas mass flow rate of 756 kg/s. Assuming the same condensation efficiency (50%) as in the NGCC example, the potential fresh water recovery is:

- 525,000 gallons per MW of capacity
  - $= 756$ kg/s × 10% × 50% / 1,000m^3/kg × 264.2 gal/m^3 × 3600 s/hr × 24 hrs × 365 days / 600 MW
- Assuming a water cost of \$0.03/100 gallon, a power plant operator could realize an annual savings of 160 \$/MW of capacity.

3.5 Specific Cooling Water Requirements in Commercial Nuclear Power

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The University of Texas at Austin

3.5.1 Introduction

In 2012 there were 65 commercial nuclear power plants in the United States operating 104 reactors (INL, 2010). Of these, 35 were boiling water reactors and 69 were pressurized water reactors (NRC, 2012). Both types operate by using the heat generated through fission to vaporize water, which is then run through turbines that are used to drive generators. Cooling water is used to remove heat from the core, cool equipment, and spent nuclear fuel.

In a boiling water reactor, steam is generated directly in the core and then run through the turbines. A secondary coolant loop is used to recondense the steam before it is sent back through the core, Figure 3-24. A pressurized water reactor, by contrast, operates with three loops, Figure 3-25. The coolant in the primary loop is run through the reactor to remove heat but the water remains in its liquid state due to high pressure. The coolant then passes through a heat exchanger, called a steam generator, where water in the secondary cooling loop is converted from liquid to steam before passing through the turbines. A tertiary cooling loop is used to recondense the steam in the secondary loop after it has passed through the turbines. Boiler water reactors have the advantage of simpler cooling systems, though they sometimes operate with a slightly reduced thermal efficiency (Schulenberg and Starflinger, 2007; Todreas and Kazimi, 1990).

The basic methods used to cool vapor power systems vary little from plant to plant, and the same technologies that are used to cool a thermoelectric plant running on fossil fuels are also used in nuclear facilities. No existing U.S. nuclear power plant currently uses the dry-cooling system. Instead, once-through, recirculating (wet-cooling towers), and cooling ponds are used to cool nuclear plants. Nuclear power plants have a few cooling requirements which are unique to the technology. Unlike conventional power systems, nuclear reactors continue to generate heat after they have been shut down (through the decay of radioisotopes that are contained in the fuel) (Ragheb, 2012).

This decay heat can present a particular problem in accident scenarios, especially if cooling water is lost. Radioactive decay continues in the fuel even after it has been removed from the reactor and placed in storage. Because of this, cooling water is required for the spent fuel storage pools into which fuel is placed after it has been discharged from the reactor (Ragheb, 2012).

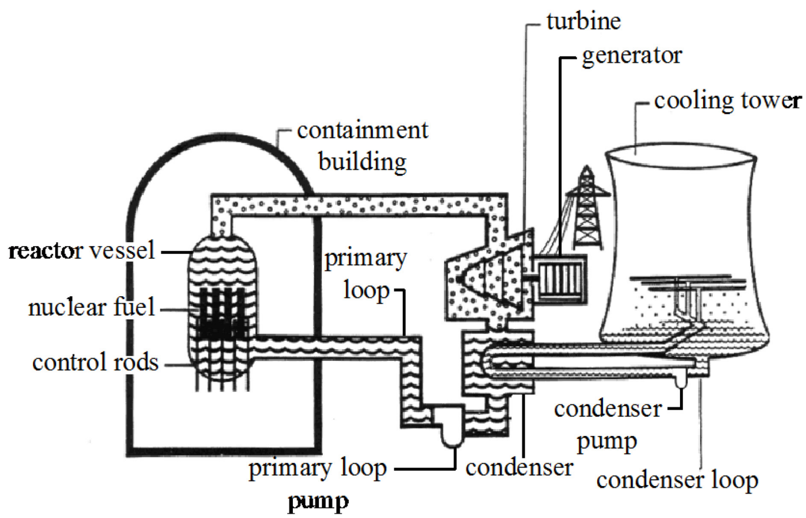

Figure 3-24. Boiling water reactor operation. The reactor core of the boiling water reactor vaporizes the water in the first (primary) loop. This vapor is used to turn the turbines and produce electricity before being cooled in the condenser by the coolant in the secondary loop. [Adapted from: U.S. Nuclear Regulatory Commission].

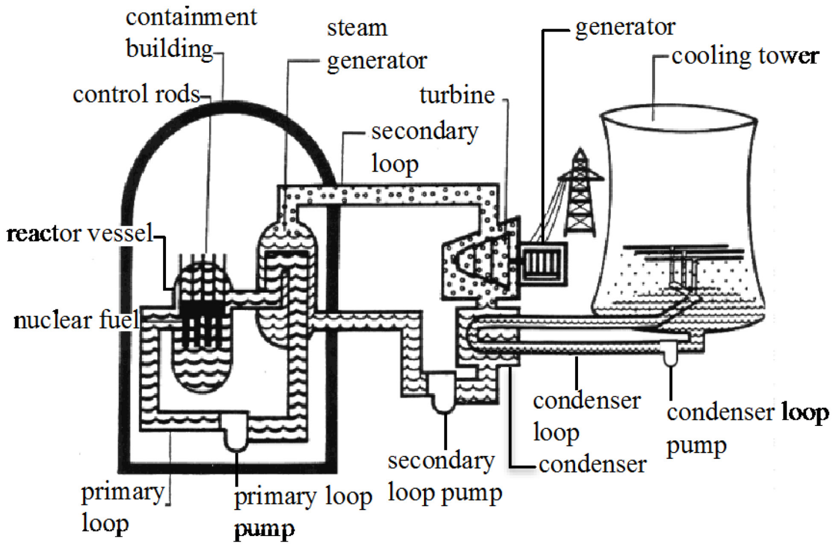

Figure 3-25. Pressurized water reactor operation. The high pressures of the core of a pressurized water reactor prevent the main feedwater in the initial closed loop from cooling. This superheated water transfers heat energy to the working fluid through the steam generator. The vapor in the closed second loop turns the turbines and is cooled in the condenser by the coolant in the open third loop. [Adapted from: U.S. Nuclear Regulatory Commission].

3.5.2 Water needs during normal operation.

The basic layout of boiling water and pressurized water plants is shown in Figure 3-24 and Figure 3-25, respectively. In both, working fluid enters the turbine as vapor, expands, and is typically ejected on the backside as a high-quality mixture of vapor and liquid. Cooling is used to re-condense the working fluid. While the main condenser in a nuclear power plant dominates the water requirements, many other essential components produce heat and must also be cooled (Lochbaum, 2007). The energy balance for cooling water flowing through the condenser is given by:

$$m_1 c_p \Delta T = x m_2 h_{\mathrm{lg}} \qquad \text{Eq. (3-22)}$$

Here $\dot{m}_1$ is the cooling water flow rate [kg/sec], c_p [kJ/kg•C] is its heat capacity at constant pressure, ΔT [C] is its temperature change, x is the quality of the two-phase mixture as it leaves the turbine, $\dot{m}_2$ is the mass flow rate of working fluid through the turbine [kg/sec], and h_{lg} is the energy required to condense the working fluid at a particular temperature and pressure [kJ/kg].

Commercial reactors in the United States have capacities that vary from 478 MWe to 1280 MWe (INL, 2010), and efficiencies that are typically between 30% and 33%. This means that between 67% and 70% of a reactor's thermal output (1,300 to 3,990 MW_{th}) is ultimately rejected into the environment through its cooling systems. Table 3-3 gives a summary of the cooling methods used by U.S. reactors, the range of their power outputs, and their cooling water needs.

Pumps, air-conditioning chillers, lubricant coolers, and other heat exchangers are cooled by a dedicated closed coolant loop called the component cooling water system (Lochbaum, 2007; NRC, 2000). Many of these systems function whether the plant is operating or in cold shutdown (Lochbaum, 2007). Heat collected by the component cooling water system is transferred through a heat exchanger to the service water system where it is often discharged to the environment (see Figure 3-26). As with all thermoelectric plants, intake water used for cooling must flow freely and be clear of debris. To achieve this, trash racks and traveling screens filter out material of different sizes (Jarrell et al., 1992).

Table 3-3. Nuclear power plant cooling Methods and Water sources. Nuclear power plants in the United States utilize either a boiling water reactor core or a pressurized water reactor core. Three basic cooling methods provide water to the condenser from one of four different water sources (INL, 2010; Union of Concerned Scientists, 2012).

	Boiling Water Reactors	Pressurized Water Reactors	Total Reactors
Number of Reactors	35	69	104
Cooling System Type			
Once-Through	13	35	48
Recirculating	17	23	40
Cooling Pond	5	11	16
Water Source			
Lake	12	32	44
River	21	23	44
Ocean	2	14	16
Wastewater	0	3	3
Range [low/high]			
Thermal Output [MWth]	1,593/3,898	1,300/3,990	1,300/3,990
Summer Capacity [MWe]	572/1,266	478/1,280	478/1,280
Condenser Flow Rate [kg/min]	946,100/ 2,838,200	1,115,600/ 4,545,110	946,100/ 4,545,100

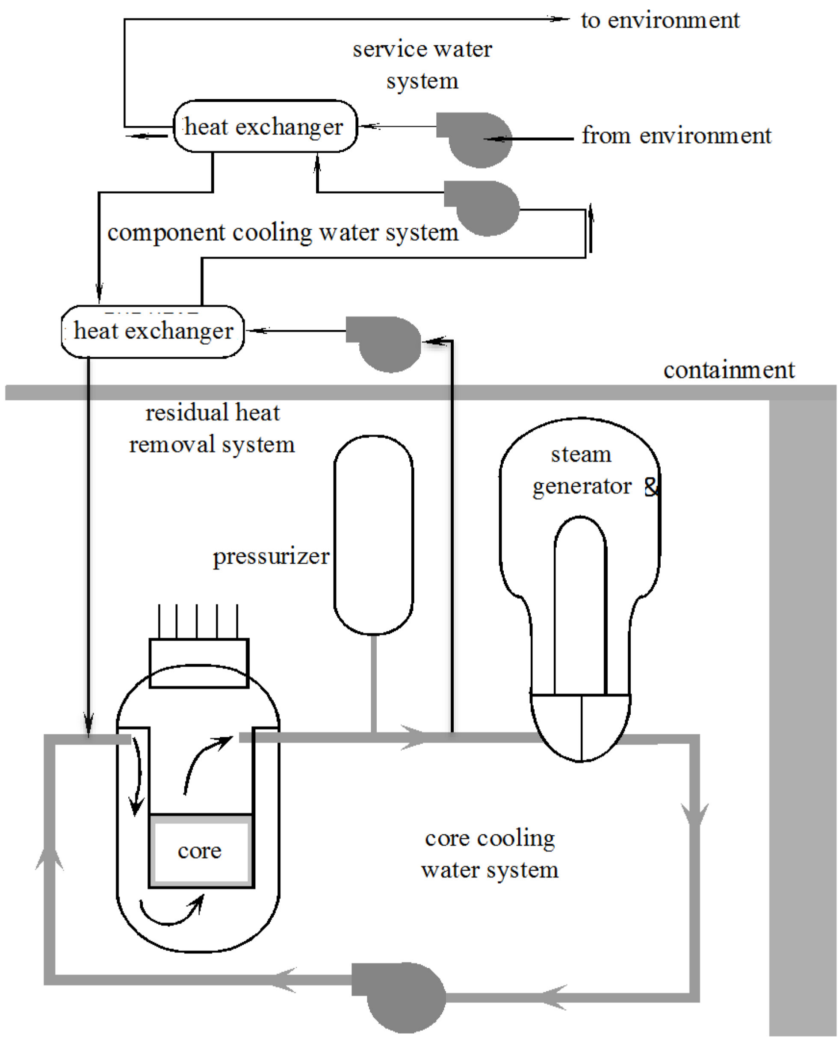

Figure 3-26. Auxiliary cooling systems in pressurized water reactor. Just as in a boiling water reactor, the necessary components required whether a reactor is operating, in shutdown mode, or during an emergency are cooled by the component cooling water system. Waste heat collected by the component system is discharged to the environment after passing through a heat exchanger to the service water system. In an emergency situation, decay heat from the reactor is passed to the component cooling water system by the residual heat removal system, and this series of pumps acts as the emergency service water. [Adapted from: U.S. Nuclear Regulatory Commission].

3.5.3 Handling of Spent Reactor Fuel

Special consideration is given to the spent fuel pool, Figure 3-27, where discharged fuel is placed until its radioactivity has decreased sufficiently for it to bundled into casks for dry storage, Figure 3-28. Because of its radioactivity, spent fuel continues to release energy, and this radioactive decay causes the fuel to be physically hot (Lamarsh, 1983), Figure 3-29. Thermal output into a spent fuel storage pool depends on the amount of spent fuel in storage as well as its properties (being highest for fuel that has recently been discharged).

Fuel for light water reactors, such as those run in the United States, is contained in a Zircaloy sleeve called “cladding.” This alloy has a thermal limit of ~1100 C (NRC, 2000), above which it will react exothermally with the oxygen in air, water, or steam to produce zirconium dioxide and hydrogen gas. Because of this, spent fuel cooling pools are typically equipped with two cooling systems on separate pumps (Weech and Lee, 1981). Generally, only one pump runs at a time unless fuel has been freshly added. In the absence of cooling and makeup water, it is possible for the water in spent fuel pools to evaporate, exposing the cladding and the fuel contained within it. It was initially thought that the inability to provide cooling for the spent fuel storage pools led to the hydrogen explosions at Fukushima, though subsequent reports have called this into question (The American Nuclear Society Special Committee on Fukushima, 2012).

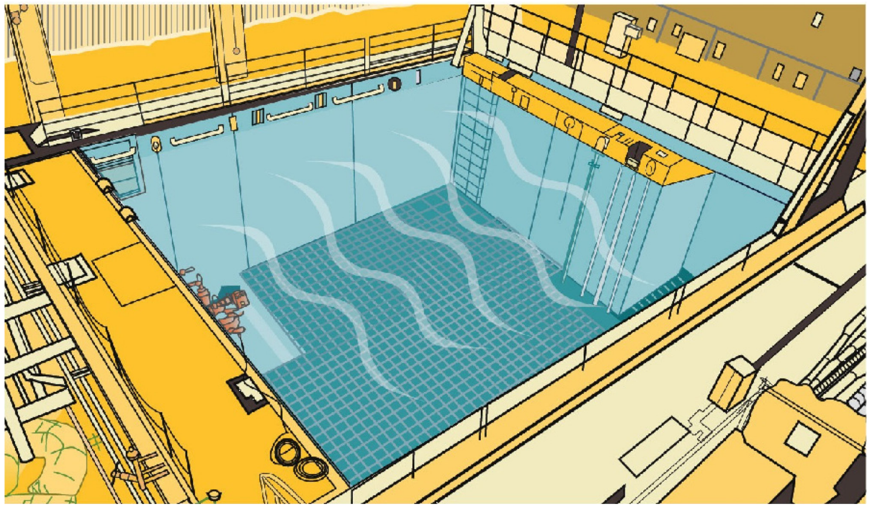

Figure 3-27. Spent fuel pool. Spent fuel pools provide continuous circulating water to remove decay heat from the used fuel rods. Without circulation, the pool would boil and evaporate leading to damage to the fuel cladding [Source: U.S. Nuclear Regulatory Commission].

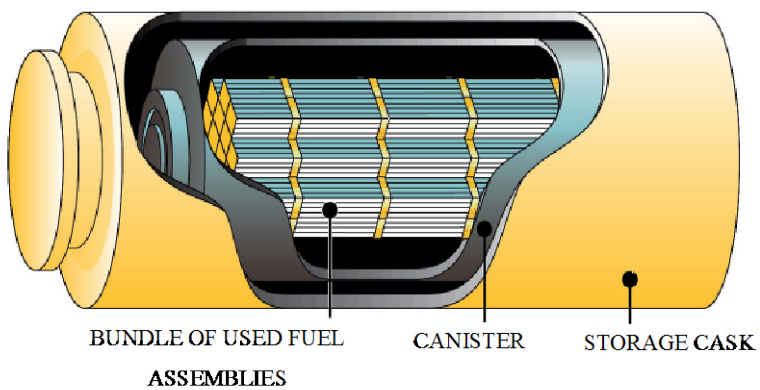

Figure 3-28. Spent fuel storage container. After several years of wet storage, fuel rod assemblies are packed into airtight containers where they will be put into dry storage [Adapted from: U.S. Nuclear Regulatory Commission].

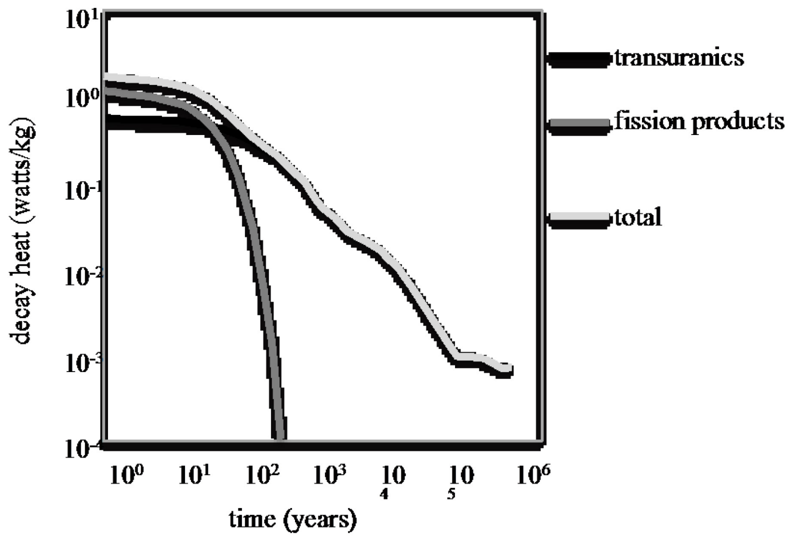

Figure 3-29. Spent fuel decay heat as a function of time. Spent nuclear fuel mostly comprises uranium, but the decay heat that it produces comes mainly from fission products (isotopes of cesium, strontium, xenon, etc.) and from transuranic elements that have been produced in the fuel (plutonium, americium, curium, neptunium). The graph shows how each of these change as a function of time, per kg of spent nuclear fuel (which does not include the mass of cladding or structural materials in the fuel assemblies). Data were generated using Origen 2.2 (Bowman and Leal, 2000).

3.5.4 Discharge of Cooling Water

The cladding that surrounds nuclear fuel is designed to keep the uranium dioxide fuel dry and radioactive material out of the coolant. However, the neutron field inside a reactor interacts with the coolant to produce small amounts of both tritium and radioactive nitrogen. The latter has a half-life of only 7 seconds and poses little environmental risk. While tritium has a half-life of slightly more than 12 years, it too is produced in negligibly small amounts. A reactor's neutron field will also interact with core structural materials that can become radioactive in the process (NRC, 2000). Coolant flowing through a reactor core will pick up small amounts of the irradiated structural materials, and this is typically removed from the cooling water using resin towers or electrostatic separation techniques before discharge. If the radioactivity of cooling water falls below established limits and it is otherwise contaminant free, it will at times be discharged to the environment if needed (Lochbaum, 2007).

If a river, lake, or ocean is used as the heat sink for a nuclear power facility, there will be environmental issues associated with thermal discharge to these bodies, just as with conventional power systems. Discharge temperature limits are typically set at the state level and vary from facility to facility. Notably, the discharge temperature limit can affect the power at which the reactor can operate. If the temperature of intake water increases sufficiently, the power level at which the reactor can operate (and still stay below discharge temperature limits) might have to be reduced. In addition, the licenses under which some nuclear power plants operate set an upper limit on the allowed temperature of intake water. Should this intake water temperature limit be exceeded, the plant will actually have to shut down, unless the license is amended (NRC, 1975; NRC, 1989; Wald, 2012).

3.5.5 Cooling After Shutdown and During Emergencies

The decay of radioisotopes produces heat in nuclear fuel even after the fission process has been brought to a halt. Computational methods are needed to accurately predict the evolution of the thermal output. However, a reasonable estimate for the decay heat can be made using (Etherington, 1958):

$$\frac{P(t)}{P_0} = 6.2 \times 10^{-2}\left[t^{-0.2} - \left(t + t_0\right)^{-0.2}\right] \qquad \text{Eq. (3-23)}$$

Here $P(t)$ is the decay power [MW_{th}], P_0 is the steady state reactor power before shutdown [MW_{th}], t is the time since shutdown [sec], and t_0 is the time that the reactor was in steady state operation at P_0 [sec].

Equation Eq. (3-23) predicts that one second after plant shutdown, a nuclear reactor generates approximately 6% of the steady state power at which it had been operating (Ragheb, 2012). A full day after shutdown, this falls to ~ 0.44%, **Figure 3-30**. Considering that the thermal output of nuclear power plants in the United States range from about 1,300 to 3,990 MW_{th}, the thermal output of a nuclear plant drops to 91 to 279 MW_{th} immediately after shutdown. One day after shutdown, a plant would still output between 6 and 18 MW_{th} (INL, 2010). Equation Eq. (3-23) is only approximately correct, and the time varying error associated with it is seen in Table 3-4. In reality, the decay power one second after shutdown is closer to ~7% of a reactor's steady state operating power (Etherington, 1958).

Table 3-4. **Substantial uncertainty associated decay heat estimation (Todreas and Kazimi, 1990).** Equation Eq. **(3-23)** is most accurate when the time after shutdown is between 10^3 and 10^7 seconds, from about 16 minutes after shutdown to about 116 days. Before or after this time window, error is significantly increased.

Time, t (sec.)	Uncertainty
$t < 10^3$	+ 20%, - 40%
$10^3 < t < 10^7$	+ 10%, - 20%
$10^7 < t$	+ 25%, - 50%

Nuclear power plants are designed to shut down automatically when their safe operating conditions are compromised. A general emergency cooling system is composed of three main features: the ultimate heat sink, a system of pumps (emergency water system), and emergency power (Lochbaum, 2007). In shutdown mode, cooling systems continue to remove decay heat from the core, the spent fuel in storage pools, and related equipment. Water requirements during shutdown are comparable for both boiling water reactor and pressurized water reactor systems.

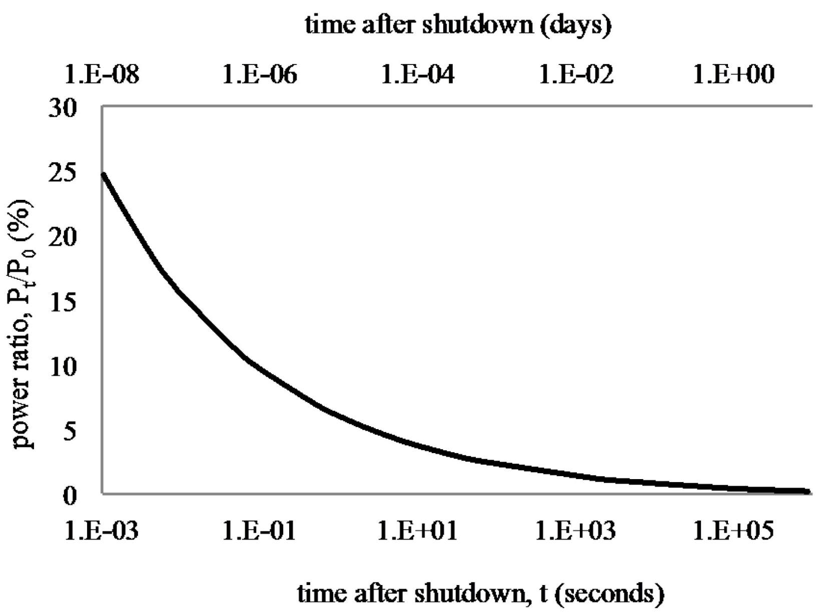

Figure 3-30. Nuclear reactor power after shutdown. Decay heat released after shutdown for a reactor operating for a span of one year. Data were generated using Equation Eq. (3-23).

The *ultimate heat sink* is a water source generally separate from the primary cooling system. It is often a large pond or reservoir reserved for emergency scenarios, though plants cooled by lakes or marine water may use these for this purpose as well. Emergency requirements for water depend on the reactor power, as well as the time since shutdown, and can range between 25,000 and 80,000 kg/min (Lochbaum, 2007). The ultimate heat sink is sized, or chosen, to provide this flow rate (and all makeup water) for a minimum time period determined in the facility design (Lochbaum, 2007).

The *emergency water system* uses at least two redundant pumps to draw water from the ultimate heat sink. This system often utilizes the pumps from the service water systems (see Figure 3-26) that are responsible for removing all non-condenser heat while the plant is active or in cold shutdown. The water is circulated through the residual heat removal heat exchangers and keeps the cores at a manageable temperature. The emergency water system pumps also provide service water to any emergency components required for maintaining a reactor in cold shutdown. Components such as the condensers for the control air-conditioning systems are integral and must be cooled during an emergency scenario. Without proper heat removal, temperature sensitive systems in the control room can malfunction.

Backup *emergency power* is another major component of the emergency cooling systems. Certain types of accident scenarios, for example the large seismic event at Fukushima and subsequent tsunami, can sever a facility from external power. Modern nuclear power facilities are required to maintain emergency generators and large-scale batteries onsite (NRC, 1975, NRC, 1989). If these systems also fail, as happened at Fukushima, external power or water must be provided within a very short time frame. Without adequate cooling, core water will begin to vaporize. Left unchecked, pressure will increase and the reactor vessel will eventually fail, causing the release of steam into the reactor's containment dome and the exposure and damage of the fuel (The American Nuclear Society Special Committee on Fukushima, 2012). If adequate cooling is still absent, decay heat will cause water to vaporize in the containment dome as well. This will again cause pressure to rise, possibly leading to failure of the containment dome.

Because of the rapid decrease in core decay heat, the most critical cooling period for a nuclear reactor is in the first few days after shutdown. Nuclear power plants are designed with multiple redundancies to ensure adequate cooling under even abnormal operation. As a result, not all of the service water pumps are in operation at any one time, and at least one will remain on standby in case another fails (Jarrell et al., 1992).

3.5.6 Advanced Light Water Reactor Designs

Reactors are now designed to have passive cooling capabilities during emergencies. Complex safety systems have been simplified to work without active components such as pumps, fans, motors, or the need for operator intervention. Instead, passive safety systems are driven by natural forces such as gravity, air circulation, and pressurized gas (IAEA, 2004). These designs also provide cooling without the requirement of power to operate or external cooling water to remove heat. The AP 600 and AP 1000 are examples of reactors with these types of passive safety systems, and both have been licensed for use in the United States (NRC, 1998; NRC, 2004).

A basic containment and reactor layout for the AP1000 can be seen in Figure 3-31. In the event of an emergency, the passive cooling system provides gravity-fed water to the reactor core from the in-containment refueling water storage tank, Figure 3-31. The storage tank acts as a heat sink for the first hour of an emergency (IAEA, 2004). After this, excess heat is dissipated through vaporization of the stored water. Natural air circulation causes the vapor to rise and condense on the inside of the steel containment dome, where it drains back down into the refueling water storage tank.

While passive cooling of the core occurs inside the reactor containment dome, the passive containment cooling system cools the exterior of the dome itself, Figure 3-31. Gravity draws water from storage tanks that are located at the top of the reactor containment dome. Water released from these reservoirs forms a thin sheet over the steel exterior, cooling the dome through evaporation. The rejection of excess heat through evaporation is supported by natural air circulation. Air is drawn in through an inlet and baffle and runs across the containment exterior. The air carries away vapor and heat as it is ejected by natural drafting out the top of the structure. The storage tanks provide a seven-day supply of water (NRC, 1998). Beyond this time, air cooling alone is sufficient to cool the containment.

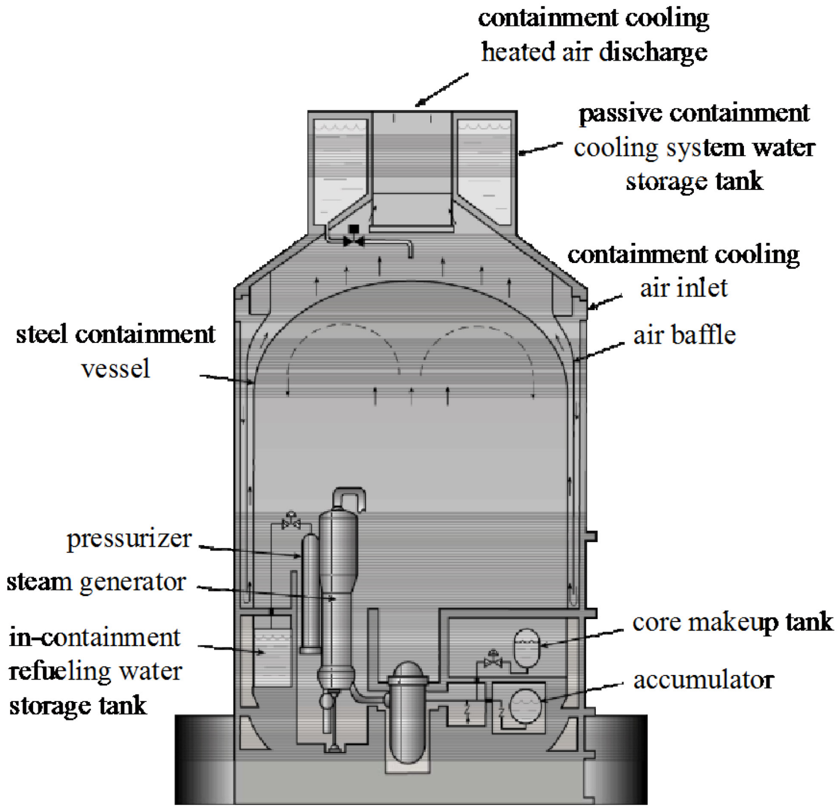

Figure 3-31. Advanced light water reactors. Reactors such as the AP600 and AP1000 utilize numerous passive systems that operate in accident conditions without outside power or water. Within the containment dome, the in-containment refueling water storage tank provides gravity-fed water to the reactor and water vapor via natural drafts. The exterior of the containment dome is cooled by water from the passive containment cooling system water storage tank and by naturally circulating air [Adapted from: U.S. Nuclear Regulatory Commission].

3.5.7 Summary

Modern nuclear power plants have many of the same cooling needs that are encountered in conventional vapor power systems. However, there are unique cooling requirements not encountered in other thermoelectric facilities: removal of decay heat from the reactor core during shutdown and spent fuel pools at all times. Failure to provide emergency cooling during accident situations can lead to the failure of the reactor vessel and possibly a reactor's containment dome. Inadequate cooling to spent fuel storage pools and a lack of makeup water can result in the loss of cooling water. If freshly discharged fuel becomes exposed, cladding temperatures can rise to a point where the cladding will react with water to produce hydrogen gas. This hydrogen gas must be properly vented to prevent risk of explosion. The same is true for inadequately cooled cladding in a reactor's core.

Because of safety concerns, modern nuclear reactor facilities are designed with multiple redundancies to ensure adequate cooling after shutdown. Nuclear reactors are now being designed to provide cooling in a passive, rather than active, manner that can run autonomously in accident situations over limited time horizons.

3.6 USGS Estimation of Water Consumption and Withdrawal—Including Forced Evaporation

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Diehl, T.H. (2012) Estimating Forced Evaporation From Surface Water. In *Third Thermal Ecology and Regulation Workshop*. EPRI, Palo Alto, CA,. 1025382. pp. 23-1–23-10.

In 2009 the Government Accountability Office (GAO) published *Improvements to Federal Water Use Data Would Increase Understanding of Trends in Power Plant Water Use*, recommending specific actions by the U.S. Geological Survey (USGS) and the U.S. Energy Information Administration (EIA) (GAO, 2009). In response, EIA and USGS established a joint technical committee including outside experts and stakeholders to discuss thermoelectric water use. EIA and USGS are also collaborating on improved reporting of the use of alternative water sources for fresh water, such as treated effluent, pumped mine water, and deep saline aquifers.

As part of its effort to improve water use data, the USGS is broadening the scope of its report on *Estimated Use of Water in the United States* for 2010 to include water consumption at thermoelectric power plants as well as withdrawal. In addition, the USGS reviewed and updated the locations reported to EIA of selected water-using power plants, and assigned these plants to river reaches and watersheds.

USGS developed a hierarchical approach to estimate water consumption and withdrawal at the power plant level. Operator-reported water use was accepted by USGS at plants where it was thermodynamically realistic. Estimates of water use based on linked heat and water budgets were used at most other plants, and average ratios of water use to electric production were applied at plants with insufficient data for constructing heat and water budgets. Estimated consumption included increased evaporation from surface waters heated by power plants with once-through cooling systems; this forced evaporation is not reported to EIA, but as GAO (2009) noted: "water consumption in these systems occurs via evaporation downstream of the plant."

USGS identified about 1,300 thermoelectric power plants with significant water use. In 2010, only power plants with 100 MW or more of installed thermoelectric capacity reported water use to EIA, and these included about 800 of the selected water-using plants.

Linked heat and water budgets were constructed for all thermoelectric plants that provided enough information on plant characteristics and operations. These budgets included estimates for water withdrawal and consumption, and estimated upper and lower limits beyond which the reported water use is inconsistent with the model's assumptions and the conservation of energy. USGS tried to frame these limits conservatively so that water use numbers outside them would indicate questionable reported numbers for water use, plant characteristics, or operations.

Many plants had reported water withdrawal and consumption numbers inside the USGS "realistic" range. For these plants, the reported water use was generally accepted. Except for forced evaporation due to once-through cooling, thermoelectric water use can be measured directly; power plants required to report water use can provide accurate figures for water use given appropriate instrumentation and reporting.

Numerous plants reported inconsistent or unrealistic water-use numbers, or did not report water use. For some of these plants, realistic water use figures were acquired from non-EIA sources. For the rest, USGS used budget-based water use estimates. Such estimates are less precise than directly measured values. In the case of some power plants, there is insufficient data on plant characteristics and operations such that it is not possible to calculate a usable heat and water budget. Average ratios of water use to electric production were calculated based on plants with good budgets or realistic reported water use, categorized on prime mover (steam or combined cycle), fuel type, and cooling system type. At plants with sparse data, technologically appropriate coefficients were used to estimate water use. These coefficient-based estimates are less precise than estimates based on linked heat and water budgets.

3.6.1 Introduction

Although water consumption by once-through cooling of thermoelectric power plants is important (Amit Kohli and Frenken, 2011; Macknick et al., 2011; Morton, 2010), there is no consensus on its magnitude or an optimal method of estimation. Published coefficients (Dziegielewski et al., 2006; EPRI, 2002b; Gleick, 1993; King et al., 2008; Macknick et al., 2011; Macknick et al., 2012; NETL, 2006a; Sledge et al., 2003; Young and Thompson, 1973) for average forced evaporation in the U.S. range from 0.015 to 4.5 liters per kilowatt-hour (L/kWh) for cooling ponds and 0.45 to 12 L/kWh for once-through cooling in lakes and rivers [0.004 to 1.2 gallons per kilowatt-hour (gal/kWh) and 0.12 to 3.1 gal/kWh, respectively]. The lack of consensus among these estimates reflects the variety of estimation methods used and suggests that some of them must be in error. Most published coefficients are presented as average or "typical" nationwide values for broad technological categories of power plants and do not reflect climatic and seasonal differences in the rate of forced evaporation or the effects of variability in plant efficiency within each technological category. There is a need for a transparent, verifiable method to estimate forced evaporation based on environmental conditions and physical constraints. Section 3.6 summarizes some of the issues surrounding forced evaporation and presents modifications to a previously published method to overcome known deficiencies.

3.6.2 Background

Forced evaporation from surface water occurs when heat is added by human activities, such as the cooling of thermoelectric power plants, and can be a substantial consumption of water in the sense of making water unavailable for other human uses. Thermoelectric water consumption, including forced evaporation and evaporation from cooling towers, was estimated in 1995 to be about 3%of human water consumption in the U.S. (Solley et al., 1998). Forced evaporation in natural surface-water bodies occurs outside the plant boundary and cannot be directly measured by the plant operator, but it is an unavoidable result of using lakes and rivers as components of cooling systems. In some cases, forced evaporation has been deemed insignificant on the scale of the stream it occurs in (EPRI, 2002a), but in river basins where water allocation has become a legal and political issue, thermoelectric forced evaporation may substantially affect the overall water budget (Kohli and Frenken, 2011).

Forced evaporation is constrained by the characteristics of individual power plants. The heat available to drive evaporation in the environment is the heat extracted from the steam by the condenser ("condenser duty"). Condenser duty excludes the heat transformed into electricity, discharged in flue gases, or conducted to the atmosphere from plant equipment. High thermal efficiency, which is limited by thermodynamic constraints and the high capital cost of high-efficiency plants, tends to produce low ratios of forced evaporation to condenser duty; low efficiency, which is constrained more loosely by the high operating costs of low-efficiency plants, tends to produce high ratios of forced evaporation to condenser duty.

Published national averages of forced evaporation have been presented using either of two types of consumption coefficients:

1. The ratio of water evaporated to net electric generation, a water-balance approach at the level of the power plant.
2. The percentage of the condenser duty that is lost to the atmosphere as evaporation, a thermodynamic approach at the level of the cooling system.

Because all such national-average coefficients are presented as constants for a given combination of fuel and cooling system type, they cannot be used to address plant-to-plant differences in efficiency and environmental conditions. Published regional and national constant percentages of condenser duty driving evaporation [such as 75 (Young and Thompson, 1973), 60 (Sledge et al., 2003; Steiner and Hogan, 1986), or 40 percent (Morton, 2010)] also fail to express the variability due to environmental conditions.

Models in which forced evaporation varies with environmental conditions date from Harbeck's (G. Earl Harbeck, 1953) pioneering study applying heat transfer theory to Lake Colorado, a cooling pond in Texas. For once-through or pond cooling in general, Harbeck (Harbeck, Jr., 1964) demonstrated that from 20% to 75%of the added heat may be lost by evaporation, depending only on water temperature and wind speed. Harbeck suggested that air temperature is an adequate surrogate for water temperature where water temperature data are not available. He presented his results as a chart, and did not suggest that the heat transfer equations be solved for each case. Huston (Huston, 1975) used Harbeck's method to estimate annual averages of forced evaporation from 37% to 54% of condenser duty over 18 major continental-U.S. river basins (Majewski and Miller, 1979). Majewski and Miller (1979) discussed heat loss and evaporation in detail, presenting nine wind functions for comparison. They adopted the same approach as Harbeck, though entirely in SI units and using a different wind function, and developed a chart similar to his. Ward developed linear approximations of Harbeck's heat transfer formulae, proposed the optional substitution of other wind speed functions, and analyzed the errors in forced evaporation that would result from the linear approximation and from errors in the estimated temperature of the heated water (Ward, Jr., 1980; Ward, Jr., 1986).

Harbeck's use of air temperature as a surrogate for water temperature has been identified as his model's main deficiency. Boyer commented that the use of air temperatures as a surrogate for lake temperatures would lead to considerable errors in forced evaporation for some lakes (Boyer, 1965). Brady and others used the same underlying equations as Harbeck to estimate percent forced evaporation (Brady et al., 1969a; Brady et al., 1969b), improving the treatment of the equilibrium water temperature and the wind function, and estimated 64%forced evaporation for a wind speed of 4 meters per second [m/s; 9 miles per hour (mph)] and a water temperature of 27^{o}C (80^{o}F) under summer conditions in Chesapeake Bay. Hu and others determined that predictions based on the method of Brady and others gave a higher and more accurate estimate of water consumption than Harbeck's method (Hu et al., 1978; Hu et al., 1981).

Williams and Tomasko applied the same underlying physics as Harbeck, Brady, Majewski, and others to the problem of forced evaporation in Chesapeake Bay and the Potomac River (Williams and Tomasko, 2009). Williams and Tomasko assumed that forced evaporation is directly proportional to the increase in plume temperature above ambient water temperature, implicitly treating the heat transfer equations as linear with respect to water temperature. Their estimates are based on the assumed area and heated water temperature of the plume, and condenser duty is not used to constrain forced evaporation. As a result of the difficulty in estimating plume characteristics, their two example calculations yield thermodynamically unrealistic results of 2% forced evaporation in one case and 200% in the other.

3.6.3 Forced-Evaporation Model

The method proposed here for estimating forced evaporation is based on that of Ward (Ward, Jr., 1980), with a few key revisions:

1. A natural water temperature is estimated based on available water-temperature data rather than air-temperature data. Typical water-temperature data sources include previously measured river temperature upstream from the plant, or in nearby lakes and streams.

2. A heat loading (i.e., condenser duty per area) is estimated or measured and used to solve the relevant equations iteratively to estimate a heated water temperature.

3. The percent forced evaporation is given by the ratio of the difference in evaporation at the two temperatures to the difference in the sum of evaporation, conduction, and radiation at the two temperatures.

Equations for heat loss can be solved for both the natural and heated water temperatures, with the estimated heated-water temperature adjusted iteratively until the difference in heat loss at the two temperatures is equal to the added heat from the power plant. Monthly average values are used for environmental variables and monthly estimates of the percent of condenser duty that drives evaporation are produced, tracking seasonal changes in water consumption. In the following equations, the units used by Ward are preserved to facilitate comparison to his and Harbeck's publications.

The total heat loss from a water surface is the sum of heat loss through evaporation, conduction, and radiation expressed in terms of energy flux per unit area.

$$H(T) = E(T) + C(T) + R(T) \qquad \text{Eq. (3-24)}$$

where *H(T)* is heat loss from the water surface, *E(T)* is heat loss through evaporation, *C(T)* is conduction, and *R(T)* is radiation, all in calories (cal) per square centimeter per day.

Evaporation is given by:

$$E(T) = \rho Lf(W)\left[e(T) - e_a\right] \tag{Eq. (3-25)}$$

Where ρ is water density in g/cm^3, L is the latent heat of vaporization in cal/g, $e(T)$ is the saturation vapor pressure in millibars at water-surface temperature T, and e_a is the vaporpressure of the overlying atmosphere in millibars, and

$$f(W) = 7.0 \times 10^{-8}(W) \tag{Eq. (3-26)}$$

where W is wind speed in miles per hour. Conduction is given by:

$$C(T) = f(W)\frac{\rho p c_p}{\varepsilon}\left(T - T_a\right) \tag{Eq. (3-27)}$$

where p is atmospheric pressure in millibars, c_p is the specific heat of air at a constant pressure, 0.24 cal/(g ^{o}K), ε is the molecular weight ratio of water vapor to dry air, and T_a is air temperature in ^{o}C. Radiation is given by:

$$R(T) = \varepsilon_r \sigma\left(T + 273\right)^4 \tag{Eq. (3-28)}$$

where σ is the Stefan-Boltzman constant [$1.17*10^{-7}$ cal/(cm^2 ^{o}K^4 day)] and ε_r is the emissivity of the water surface, 0.97. The difference between heat loss at the natural water temperature and at the heated water temperature is:

$$H(T_H) - H(T_N) = \left[E(T_H) + C(T_H) + R(T_H)\right] - \left[E(T_N) + C(T_N) + R(T_N)\right] \tag{Eq. (3-29)}$$

where T_H is the heated water temperature and T_N is the natural water temperature, both in ^{o}C.

The difference in the heat loss at the two temperatures $[H(T_H) - H(T_N)]$ is set equal to the added heat from the power plant (condenser duty) by iteratively adjusting the heated water temperature (T_H). The ratio of forced evaporation to condenser duty is given by:

$$FE = \frac{E(T_H) - E(T_N)}{H(T_H) - H(T_N)} \qquad \text{Eq. (3-30)}$$

Ward (Ward, Jr., 1980) demonstrates that additional heat losses through evaporation, conduction, and radiation are approximately linear functions of an imposed increase in water temperature, and based on this approximation the ratio of increased evaporation to the total increase in heat loss is a function of only water temperature and wind speed. These linear approximations are not needed if the equations for evaporation, conduction, and radiation are evaluated at the natural water temperature and the heated water temperature. If the imposed heat load is distributed over an assumed area, the heated temperature can be solved for iteratively, and the share of evaporation in the increased heat dissipation can be calculated directly.

Solution of these equations over a range of environmental conditions demonstrates that *forced* evaporation is insensitive to air temperature and humidity, although these variables strongly affect the *overall* evaporation rate. Plotted results approximately reproduce Harbeck's (Harbeck, Jr., 1964) chart (Figure 3-32). Errors in either the natural water temperature or the estimated heat loading produce an error in the heated water temperature, and, as discussed by Ward (Ward, Jr., 1980), each degree Celsius error in heated water temperature produces an error of about 1% of condenser duty in forced evaporation.

Because all three forms of heat loss increase about linearly with increasing water temperature, the change in water temperature because of added heat and the corresponding increase in forced evaporation are proportional to the heat added per unit area. For water starting near 0^{o}C, forced evaporation increases about 15% for each megawatt (thermal) added per hectare; for water starting near 30^{o}C, it increases about 4% for each megawatt (thermal) added per hectare (Figure 3-33). Selection of a different wind function can shift the relation of forced evaporation to water temperature by several percent at a given wind speed (Figure 3-34). Therefore, the selection of the appropriate wind speed function for once-through cooling remains an important open question.

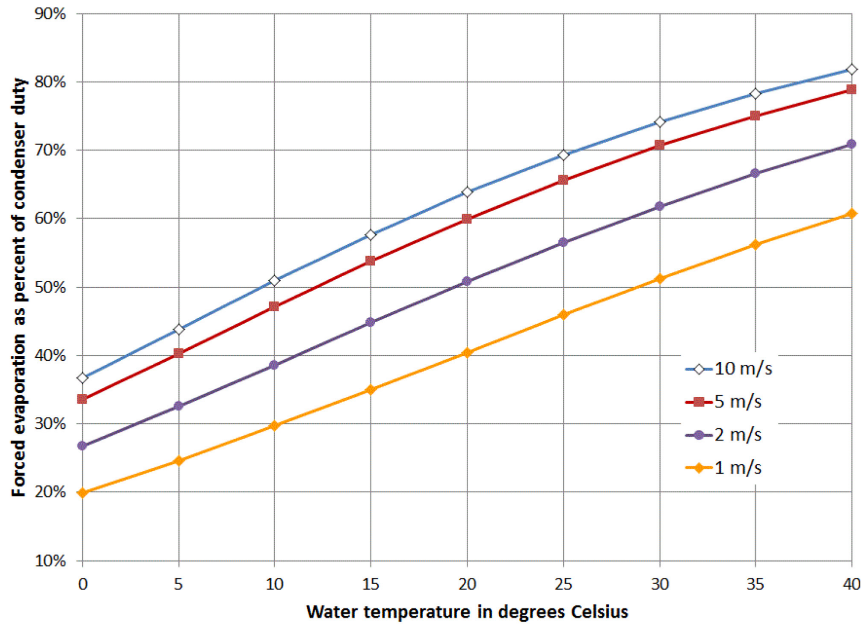

Figure 3-32. Forced evaporation as percent of condenser duty as a function of heated-water temperature and wind speed.

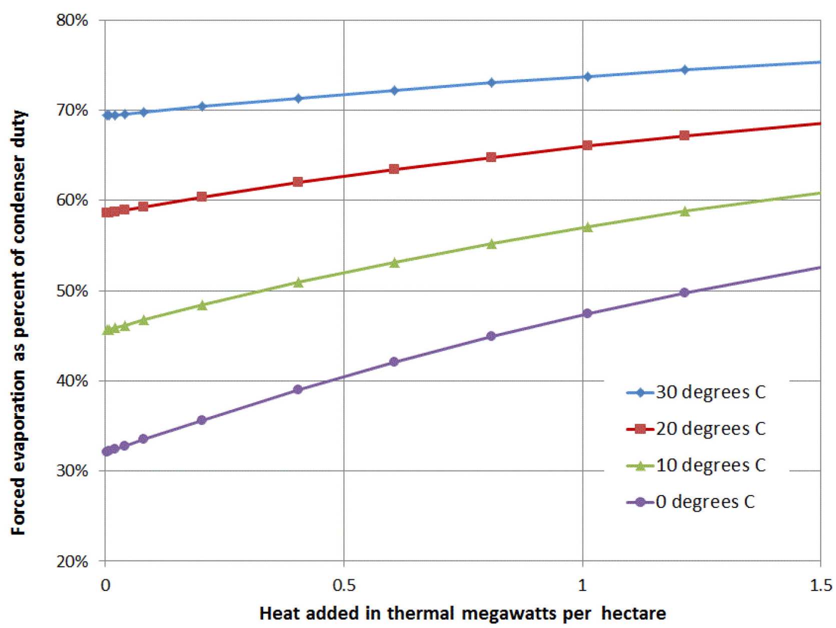

Figure 3-33. Effects of heat loading on forced evaporation at 4 m/s (9 mph) wind speed and four natural water temperatures representative of the continental U.S.

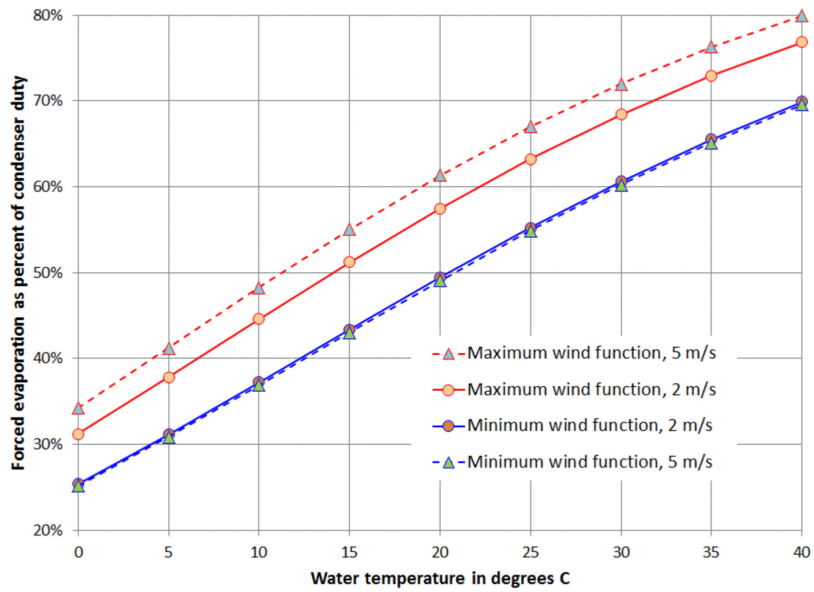

Figure 3-34. Relation of forced evaporation to water temperature for the largest and smallest values of wind functions reviewed by Majewski and others (1979) at wind speeds of 2 and 5 m/s.

The ratio of forced evaporation, a thermodynamic consumption coefficient, can be used to produce a corresponding water-balance forced-evaporation coefficient by combining it with estimated characteristics of the power plant heat budget: the thermal efficiency of net electric generation, the boiler efficiency, and the (small) percentage of fuel heat lost directly to the air by plant equipment.

The dimensionless ratio of condenser duty to the energy embodied in net electrical generation is given by:

$$\frac{CD}{NG} = {(BE - TE - AL)}/{TE} \qquad \text{Eq. (3-31)}$$

where CD is condenser duty, NG is net electrical generation, BE is boiler efficiency, TE is the thermal efficiency of net electrical generation, and AL is heat lost to the air from plant equipment.

The water-balance forced-evaporation coefficient (FEC), in L/kWh, is given by:

$$FEC = \left[\frac{CD}{NG} \cdot FE\right] \Big/ H_{vap} \qquad \text{Eq. (3-32)}$$

where H_{vap} is the heat of vaporization of water at the natural water temperature, in kWh/L.

3.6.4 Discussion

The proposed method can be applied at scales from the individual plant to the nation. For individual plants where the necessary environmental variables and plant heat-budget characteristics can be estimated, it provides a “first cut” estimate of forced evaporation that can be refined using more detailed modeling and locally collected data. Huston[16] provides an example of a regional model that might be updated. The application of this model at the national scale, using average values of environmental variables and plant characteristics, can provide a first-approximation thermodynamic test of the published water-balance coefficients of forced evaporation that identifies those that are thermodynamically implausible.

For example, assume the typical value of annual average wind speed over the eastern U.S.—the geographic area in which cooling ponds are relatively common—to lie between 3m/s and 5 m/s, and the average cooling pond temperature to lie somewhere between 15°C and 20°C. Reasonable assumptions for average plant characteristics are 33%net thermal efficiency for both nuclear and fossil-fueled plants, 89% boiler efficiency and 3% heat loss outside the cooling system for fossil-fueled plants, and 100% nominal boiler efficiency and 1% heat loss outside the cooling system for nuclear plants. Condenser duty under these assumptions would be about 5,700 kilojoule per kilowatt-hour [kJ/kWh; 5,400 British thermal units per kilowatt-hour (Btu/kWh)] for fossil-fueled plants and 7,100 kJ/kWh (6,700 Btu/kWh) for nuclear plants. Forced evaporation from cooling ponds under these environmental conditions would be 50% to 60%of condenser duty, or from 1.2 to 1.4 L/kWh (0.31 to 0.37 gal/kWh) for fossil-fueled plants and from 1.5 to 1.8 L/kWh (0.39 to 0.46 gal/kWh) for nuclear plants.

Coefficients for consumption at plants with cooling ponds that have been used as the basis for estimates of present and future thermoelectric water needs include some statistically estimated coefficients (Dziegielewski et al., 2006; NETL, 2006a) that fall outside these ranges. These departures from thermodynamic plausibility suggest that the assumptions of the statistical analysis need to be reassessed.

The method proposed in this article has three major sources of uncertainty:

1. The estimation of a natural water temperature in the absence of added heat.
2. The estimation of heat loading in a lake or river plume.
3. The selection of a wind function.

Increased collection of water temperature data and thermal models that accurately estimate natural temperatures in lakes and streams could be used to reduce errors in the assumed baseline water temperature. Plumes could be modeled to better estimate thermal loading. The differences among published wind functions suggest potential for improvement, and perhaps wind functions that depend on the characteristics of the water body could be developed. Existing wind speed functions were developed from studies of lakes and ponds, not rivers, and it may be difficult to define a wind speed function for rivers on the basis of empirical water-balance studies. Case studies of water and heat budgets for thermal plumes and cooling ponds may help reduce all three types of uncertainty. Applications of this model should include evaluation of the choice of a wind speed function and the level of uncertainty in the input wind speed and water temperature; results should be presented with an explicit discussion of their precision.

3.6.5 Conclusion

As noted previously, published national-average forced-evaporation coefficients cover a range so broad that they cannot all be accurate. Unreliable estimates of forced evaporation at individual plants may lead to flawed assessments of the plant's environmental effects; application of invalid coefficients of forced evaporation can distort regional and national assessments of choices among cooling technologies. This paper shows that thermodynamic constraints on forced evaporation can be quantified. Such constraints should be considered in future estimation of forced evaporation and used to evaluate the plausibility of existing forced-evaporation coefficients.

3.7 Evaporation Suppression From Reservoirs

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Once-through cooling of power plants requires access to a body of water such as a lake, reservoir, cooling pond or river. These water resources are becoming more and more oversubscribed as population growth and economic development make greater demands on finite supplies of freshwater. Droughts of growing severity also reduce the amount of water that can be accessed, particularly in critical summer months when peak electrical demand can occur during periods where water resources are at their lowest. Electrical power production is threatened when water levels approach water intake heights, requiring a shutdown or reduction in power plant operation. Such shutdowns or reductions might be due to government regulations on effluent temperatures, agreements with other water users, or environmental restrictions such as for in-stream flows. Ensuring that water levels do not reach such critical states is extremely important. When a power plant shares a reservoir that is also used for municipal water supply, there are other avenues for reduced water use, such as conservation. However, only so much can be expected from this approach and, especially during drought years, water levels might fall to dangerous heights regardless of the actions of other stakeholders.

Evaporation represents a large component of lost water from a reservoir. As one example, in the northwestern portion of South Carolina, 51.7 inches (131 cm) is lost per year (averaged from 1950 to 1992, South Carolina Department of Natural Resources). In the Southwestern U.S., such losses are even larger. For example, near Lake Mead yearly evaporation is 76.0 inches (193 cm) (averaged from 1953 to 1995) (Westenburg et al., 2006). Such losses might represent a small fraction of the overall volume of a reservoir during typical operating conditions. However, when reservoir levels approach cooling intakes, such losses may make the difference between continued operation and shutdown. A potential method for preventing such a situation is to suppress evaporation. Of course such approaches also increase reservoir temperatures since evaporative cooling is also lost when evaporation is suppressed. Nevertheless, under certain circumstances the suppression of evaporation may be desirable when the increase in temperature caused by evaporative suppression is more than compensated for by maintenance of a water level that permits continued plant operation.

Surfactant monolayers are one approach for the reduction of evaporation. This method, though well studied, has not been employed in any significant way in the power industry at the present time. However, further restrictions on oversubscribed water resources may make this method, which perhaps was not economically viable in the past, more lucrative in the future.

Surfactant monolayers are single molecule layers of organic molecules that form at the interface between a gas and liquid. The word surfactant is a contraction of "surface active agent" and refers to molecules that change the surface tension of the interface. Surfactant monolayers are ubiquitous on water surfaces and can be indigenous or introduced artificially. In addition to reducing surface tension, and of primary interest here, surfactants also impart the property of elasticity to a water surface, causing it to behave in a way that resists compression and re-expands after being compressed. This property restricts the motion of water near the interface, causing surface velocities to be lower than would otherwise be the case.

It has long been known that certain types of surfactants can impede evaporation (Jones, 1992; Katsaros and Garrett, 1982; Krmoyan et al., 1966; La Mer, 1962; Sebba and Briscoe, 1940). This reduction in evaporation is due to two effects, either or both of which may play a role (Bower and Saylor, 2013). The first, which many surfactants do, is reduce the temperature of the water surface (Jarvis, 1962; Jarvis and Kagarise, 1962; Jarvis et al., 1962). This is achieved by the elasticity that restricts lateral motion, keeping surface water in place and allowing it to be cooled to a lower temperature by evaporation than would otherwise be the case. The elasticity of a monolayer also reduces subsurface convective transport, which also serves to reduce the surface temperature (Bower and Saylor, 2011; Navon and Fenn, 1971). The usual parameterization of evaporation takes the form:

$$\dot{m}'' = f(u)(p_s - p_a) \qquad \text{Eq. (3-33)}$$

where $\dot{m}''$ is the evaporation rate per unit area, p_s is the water vapor pressure at the air/water interface, p_a is the water vapor pressure in the bulk air, and $f(u)$ is the wind speed function that accounts for the sensitivity of the evaporation rate to wind, evaluated at the average wind speed u (Brutsaert, 1982; Jones, 1992) Equation Eq. (3-33) shows the sensitivity of the evaporation rate to water surface temperature via the term p_s. This is the saturation vapor pressure for water, at the temperature of the water surface. Thus, all other quantities held constant, increasing the water surface temperature increases the evaporation rate. Hence, by reducing surface temperature via the mechanism described above, p_s is reduced, resulting in a reduced evaporation rate, $\dot{m}''$.

The second, and most important, way in which surfactants reduce evaporation is when the monolayer provides an actual physical barrier to the underlying water molecules. The exact mechanism by which this occurs is not entirely clear and several theories have been proposed (Archer and La Mer, 1955; Barnes, 1997; Barnes and Quickenden, 1971; Barnes et al., 1970; Blank, 1964; Blank and La Mer, 1962; Dickinson, 1978; Langmuir and Schaefer, 1943), but it is generally understood that the monolayer molecules are organized in close enough proximity to each other to restrict the diffusion of water molecules across the film, thereby reducing the evaporation rate. This type of evaporation suppression is quantified by a resistance defined as:

$$r = A(c_w - c_b)\left(\frac{1}{\dot{m}_f} - \frac{1}{\dot{m}_w}\right) \qquad \text{Eq. (3-34)}$$

where A is the area exposed to evaporation, c_w and c_b are the water vapor concentrations at the liquid water surface and in the bulk air, respectively, and $\dot{m}_f$ and $\dot{m}_w$ are the evaporation rates of the film-covered water surface and the clean water surface, respectively (Barnes and La Mer, 1962a). Many surfactants have been investigated in the lab. Some commonly studied monolayers are octadecanol, hexadecanol, stearic acid and methyl stearate. Many factors affect the evaporation resistance r, including the degree of compression of the monolayer, the temperature, and the presence of impurities. However, in laboratory environments significant reductions in evaporation can be obtained with values of r approaching 7 sec/cm (Barnes and La Mer, 1962a). The literature has in general shown some degree of variability in evaporation suppression for a given monolayer under nominally identical laboratory conditions, much of which is attributed to impurities (Barnes and La Mer, 1962b). Of course the addition of a chemical to a reservoir raises concerns, particularly when the reservoir is used for irrigation or by a water provider for human consumption. Nevertheless, it should be noted that monolayers are literally a single molecule thick and hence the total mass used is quite small. And, while some surfactants may present toxicity issues, others, such as stearic acid occur naturally in animal and vegetable fats.

In laboratory environments, evaporation can generally be suppressed significantly and for long periods of time. The utilization of surfactant monolayers to reduce evaporation on actual reservoirs and impoundments has also shown success, but the duration of evaporation suppression has been a challenge that restricts its utility. For example, Vines (Vines, 1962) showed a 50% reduction in evaporation from reservoirs using cetyl alcohol, but this reduction decayed significantly in the presence of wind, a result observed by other researchers (La Mer and Healy, 1965). In addition to this wind effect, monolayers are also known to degrade due to bacterial decomposition (Chang et al., 1959) and dissolution into the water (Mansfield, 1959). Methods for overcoming these issues have never been addressed in a manner that has made the use of these monolayers cost-effective, or has made them appear cost-effective. Much of the research in this area occurred in the 1950s and 1960s and was not embraced by water resources stakeholders. However, recent droughts in both Australia and the U.S. have spawned new interest in this method. Recent research on evaporation suppression in field environments conducted in Australia have taken a more pragmatic approach (Brink et al., 2009a; Brink et al., 2009b), where researchers have recognized the finite lifetime of monolayers and have sought methods to manage their distribution in a cost-effective manner. It is likely that as droughts become more severe, research like this will become more common, and actual application of monolayers to mitigate evaporative loss in the field will come to fruition.

3.8 Considerations for Water Quality and Treatment for Power Plant Cooling Water

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CDM Smith

Water withdrawal for thermal cooling represents a significant percentage of total water withdrawal, ranging from 81% to 15%depending on the geographic region in the United States (EPA, 2012). Reclaimed water offers some significant advantages to help meet cooling water demands in the electric power industry, allowing the existing source waters to be used for other purposes, including potable water use. The quality of reclaimed water is dependent on the background water quality used to transport sanitary waste to a wastewater treatment plant (WWTP) and on the processes used at the WWTP to remove contaminants from the wastewater. In the United States, perceptions of the water quality required for cooling purposes varies from the East Coast to the West Coast. Demands for low total dissolved solids (TDS) and low hardness water are typical on the East Coast, with facilities on the West Coast, typically in more water-constrained areas, treating available water to meet their process requirements.

As a general rule, water used for power plant cooling operations on the U.S. East Coast is soft with low TDS, while water further west tends to be harder and have higher TDS levels. Initial designs for thermoelectric cooling operations typically account for the existing water quality, and the choices of materials of construction for facilities, piping, and equipment are based on the anticipated beginning water quality as well as the calculated water quality when blowdown is necessary. Reclaimed water can add between 250 and 500 milligrams per liter (mg/l) of TDS to the TDS level existing in the potable water system. This increase in TDS and hardness has a more significant impact on the ability to use reclaimed water in place of low TDS water, or soft water, as the reclaimed water quality could potentially already be at the intended concentration of cooling tower blowdown water. Examples of selected TDS and hardness criteria [expressed in milligrams/liter (mg/l)] available in the reclaimed water source are shown in Table 3-5. Based on the criteria shown in Table 3-5, the DCO Marina Thermal Facility would not be able to use potable water from San Antonio, TX, with a TDS of 297 mg/l and hardness of 263 mg/l (Vandertulip, 2013).

If an East Coast utility has designed for a feed water quality based on a maximum TDS of 100 mg/l, an alternate reclaimed water supply with 500 mg/l may impact the number of cycles of concentration for which the water can be used in a cooling tower. Also, this high TDS reclaimed water supply could potentially affect equipment sensitive to higher TDS concentrations. In contrast, reclaimed water supplied to the Palo Verde Nuclear Generating Station in Arizona has 1,200 mg/l of TDS, and Arizona Power provides onsite treatment to soften the water to obtain 23 to 25 cycles of use, whereas most facilities operate at five cycles (Day and Lotts, 2008). The impact of increasing a cooling water source TDS by 400 mg/l is more pronounced when starting from a datum of 100 mg/l compared to starting at a TDS concentration of 1,200 mg/l. Scale-forming potential is another significant water quality parameter to determine and monitor in selecting alternate waters and maintaining a balance in number of cycles of operation, chemical cost, and water cost.

Table 3-5. TDS and hardness criteria/quality for select reclaimed water sources used in wet-cooling towers.

Energy Facility/Utility	TDS (mg/l)	Hardness (mg/l)
DCO Energy Marina Thermal Facility, Atlantic City, NJ	< 100	< 30
JEA, Jacksonville, FL	500	
West County Energy Center (FP&L), West Palm Beach, FL	< 750	< 210
Town of Zebulon Little River WWTP, Raleigh, NC Utilities	325	47
San Antonio Water System (SAWS), San Antonio, TX	720	280
Palo Verde Nuclear Generating Station Tonopah, AZ	1200	300

Reclaimed water imported to the Palo Verde Nuclear Generating Station has high TDS and hardness as mentioned above. The reclaimed water also has significant scale-forming potential that requires an onsite lime softening water treatment plant to reduce the scale-forming constituents as shown in Table 3-6.

Table 3-6. Influent/effluent data at Palo Verde Water Reclamation Plant (Day and Lotts, 2008).

Scale Forming Constituents	Influent Quality (mg/l)	Effluent Quality (mg/l)
Alkalinity (as $CaCO_3$)	189	27
Calcium (as $CaCO_3$)	183	73
Magnesium (as $CaCO_3$)	123	15
Silica	19	3.5
Phosphate	10	<0.1

In the U.S., state-issued discharge permits control the quantity and quality of wastewater discharges, and the quality required to meet stream quality standards has continued to increase in recent years. Therefore, the quality of water available for reuse has continued to improve and, in some states, certain discharge permits require near potable quality water. For most cooling and industrial process water purposes, having an adequate quantity of water at a consistent quality allows the industrial user (power plant) to provide any incremental treatment to deliver the quality of water it deems appropriate for its intended use. Reusing this highly treated water for an additional purpose allows other source water to be used first for a domestic use. This integrated approach is more sustainable and cost-effective than a single use of a water source.

By using reclaimed water instead of either community potable water or the same source water (untreated) used for the community potable water supply, a power plant allows the community to defer cost of expanding the potable water system to meet increased demands from both higher domestic use and the power industry. By reusing water for cooling, the power company can reduce the water footprint and energy footprint for the entire community. Reusing reclaimed water might also allow a community to delay improvements to wastewater plants if the community were to continue discharge into a stream at the same or higher wastewater flows. This happens because new, more stringent discharge standards are typically applied to an existing permit when a community seeks modification for increased discharge volume. This delay can also occur when an existing permit is near the expiration date and new discharge limits are being applied to meet downstream receiving water quality. When reclaimed water is reused instead of discharged as effluent, there are fewer nutrients and contaminants entering the stream, which has the same net effect of reducing loading on the stream.

The two offsets to potable water and wastewater expansion cost that can be anticipated by a community are two of the reasons that reclaimed water is typically priced lower than the local potable water supply. This lower price and the ability to contract for the supply over an extended service period make reclaimed water attractive for thermal power plant cooling because the power plant operator can define his future cost for cooling water as a component of the service cost. While use of reclaimed water may reduce the number of cycles of operation, there is still value in this approach. For instance, if the cycles of operation are reduced from five to four cycles (20% reduction), but the cost of reclaimed water is one-half the cost of the current water supply, the cost of reclaimed water for cooling is approximately 60% that of the current water supply. Chemical treatment cost may be slightly more, less, or nearly equal to chemical cost for the existing water supply, depending on the choice of treatment chemicals. The cost of water, chemicals, and components of construction are better controlled for new facilities but need not limit use of reclaimed water for cooling water in power production when converting to reclaimed water as a new supply source.

3.9 Nomenclature

CCM	Condensate collection manifold
PPWD	Parallel path wet-dry (cooling system)
PCS	Parallel condensing system
SDM	Steam distribution manifold
TED	Turbine exhaust duct

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4 Economic Considerations and Drivers

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4.1 Introduction

The cooling systems at steam-electric power plants represent an important element of the total plant cost of electricity due to capital costs, operating costs, and environmental compliance. The choice of cooling system has a significant effect on plant economics because of the effect on plant efficiency and capacity, and this choice can be affected by climate and hydrology. For example, in some cases a cooling tower can operate more efficiently than a once-through system if water intake temperatures are high, and in other cases the opposite can be true.

Different cooling systems affect the ability of plant operators to meet environmental regulations intended to minimize harm from thermal discharge and from entrainment and impingement of aquatic organisms. In addition, cooling systems are usually the power plant system that uses the most water. As the availability of fresh water becomes a more critical issue in many parts of the country, minimization of water consumption for power plant cooling has become an important objective.

While water-conserving cooling alternatives are available, they often come at a high price in the form of increased capital and operating cost and a significant reduction in plant efficiency and output. Therefore, it is important both to select an optimized design for each alternative system and to conduct a thorough, consistent comparison of the cost and performance of the alternatives.

4.2 Cooling System Alternatives

Detailed descriptions of the relevant cooling systems are presented in Section 3.1. In the context of cost/performance comparisons several points are noteworthy.

4.2.1 Once-Through Cooling

Once-through cooling systems condense the turbine exhaust steam in a water-cooled surface condenser. The cold cooling water is withdrawn from a natural source water body and passes once through the condenser, where it is warmed by absorbing heat from the condensing steam. The warmed cooling water is then discharged into the receiving water body. In the United States, once-through cooling was the cooling system of choice up to the 1980s (see Figure 1-4). Over 1,200 generating units at about 500 plants currently operate on once-through cooling, using approximately 817 cooling systems (as shown in Figure 1-4).[21] It is the least costly cooling system, has the lowest operating power requirement, and has the least effect on plant efficiency and output. However, it requires the withdrawal and discharge of the largest quantities of water. Since the implementation of Phase I of the 316(b) regulations (see Chapter 2), new plants will be rarely constructed with once-through cooling systems.

4.2.2 Closed-Cycle Wet Cooling

Closed-cycle wet cooling is similar to once-through cooling in that steam is condensed in a water-cooled surface condenser. However, rather than being returned to the source, the heated condenser cooling water is sent to a cooling element, typically a mechanical-draft wet-cooling tower (or cooling pond, lake, or canal), and then returned to the condenser inlet. It is currently the most common system of choice for new plants in the U.S. (see Figure 1-4), primarily on the basis that it satisfies the environmental regulatory requirements of Sections 316(a) and 316(b) of the Clean Water Act (EPA, 2002a; EPA, 2002b).

While closed-cycle cooling is more costly, has higher operating power requirements, and reduces plant efficiency more than once-through cooling, it has lower costs and penalties than alternative, water-conserving (e.g. “dry” or “hybrid”) systems. While the water withdrawal rate for closed-cycle wet cooling is far less than that for once-through cooling (typically 2% to 10%), it should be noted that the water consumption rate, as a result of the evaporative cooling process, is higher (see Chapters 1 to 3).

4.2.3 Dry Cooling

Dry cooling, in which the heat of condensation is rejected directly into the atmosphere, can be one of two types. *Direct dry cooling,* in which steam from the turbine is ducted directly to an air-cooled condenser (ACC); and *indirect dry cooling,* in which the steam is

[21] Due to power plant configurations and the manner in which data are submitted (see Section 2.4), it is generally not possible to directly correlate power plant capacity or generation to each cooling system at a power plant that can have multiple generators and cooling systems, as well as types of generators and cooling systems.

condensed in a conventional, water-cooled surface condenser and the heated cooling water is cooled in an air-cooled heat exchanger (ACHE). Direct dry cooling use has increased in the U.S. during the past 30 years, with approximately 25 GW installed since 1980. It is typically the most costly system with the highest operating power requirement and the greatest impact on plant efficiency and output. However, it uses no water for cooling, hence reducing the overall plant water requirement by as much as 90% or more.

There are currently no indirect dry systems in use in the U.S., but they may be selected at some future nuclear plants where cooling water is unavailable and the use of direct dry cooling may be problematic on safety grounds (EPRI, 2012b).

4.2.4 Hybrid Cooling

Hybrid cooling, or wet/dry cooling, uses substantially less water than closed-cycle wet cooling, is less limiting of plant performance than dry cooling, and usually costs less than dry cooling. Hybrid systems typically are configured with a direct dry section, consisting of an air-cooled condenser operating in parallel with a wet section, consisting of a steam surface condenser paired with a wet-cooling tower, to cool the recirculating condenser cooling water. Hybrid systems to date have been used in the U.S. on coal-fired steam plants, gas-fired combined-cycle plants, and waste-to-energy plants (EPRI, 2012a).

Hybrid systems are typically sized to consume from 30% to 70% less water than a closed-cycle wet-cooling system. Those designed for 50% water conservation in hot, dry areas can be expected to cost from approximately 75% to 90% of an all-dry system with an ACC.

The application of hybrid cooling to nuclear plants is uncertain. At the present time, a hybrid system at a nuclear plant would likely be designed with an indirect dry section using an ACHE in series or parallel with the wet section. Hybrid systems with indirect dry-cooling sections are typically more costly and more limiting of plant performance than hybrid systems with direct dry-cooling sections.

4.3 Cooling System Selection Methodology and Trade-offs

A realistic comparison between the cost and performance of alternative cooling systems must meet the following criteria:

1. The comparison must be made between optimized systems. An optimized system is one that minimizes all the cooling system related costs over the life of the plant.
2. The optimization (or cost minimization) must include all costs affected by the choice and performance of the selected cooling system.

The choice, design, and subsequent operation of a cooling system affect many elements of plant and power generation costs. The cost factors included in this analysis are:

- Costs specific to cooling system
  - Capital cost of cooling system components
  - Operating and maintenance costs of cooling system
- Plant costs affected by cooling system choice
  - Cost of water used by the plant
  - Water related costs of delivery, treatment, and wastewater discharge or disposal
- Costs of other plant equipment
- Cooling system related "penalty" costs
  - "Heat rate" penalty from influence on plant efficiency throughout the year
  - "Capacity" penalty from potential limitation of full-load output during the hot periods of the year when the demand typically peaks

As discussed in Chapter 2 on environmental context and impacts, "all costs" might also include environmental and other externalities which occur outside the boundary of the physical power plant infrastructure. Including such costs quantitatively into an economic analysis is not always straightforward or possible, however, and some people believe that not all of these externalities can be adequately factored into a cost-benefit analysis. However, there can be substantial, useful insight derived from a cost comparison of all of the major factors that relate to the engineering design of the power plant. This section presents such an analysis.

4.3.1 *Costs Specific to Cooling System*

Capital costs of the cooling system, in addition to the equipment costs for each of the system components, include delivery to the site, erection/installation costs, and interconnection to the plant systems.

Operating and maintenance costs consist of the main components. The operating costs primarily include those for running fans and pumps. These are closely related to the initial design choice. Maintenance costs include not only the routine inspection and general maintenance activities associated with heat transfer and rotating equipment, but also water quality control for wet systems, periodic component and structural repair and replacement (mainly for wet systems), and periodic major surface cleaning for dry systems.

4.3.2 *Plant Costs Affected by Cooling System Choice*

Water-related costs for thermal power plant cooling, cleaning, or other operations, include multiple aspects:

- The cost of obtaining ownership rights to an adequate supply (for diverting water from the environment).
- The cost of transporting the (diverted) water to the site.
- The cost of appropriate treatment of diverted or withdrawn water for the intended application.
- The cost of disposing of any residual water or treatment brine that may or may not be discharged to the environment.

These water costs are highly variable. The separate cost components are discussed in an EPRI report (EPRI, 2011b) and summarized in Table 4-1. The water costs at any particular plant can influence the choice of cooling system, with very high costs encouraging the use of more water-conserving cooling options. A probable range of water costs from $1 to $4 per thousand gallons ($/kgal) of water is reasonable for most estimating purposes.

Table 4-1. Range of cost of various elements of water use.

Cost element	Minimum	Low	Medium	High
	$/kgal	$/kgal	$/kgal	$/kgal
Acquisition	Nil	$0.50	$1.25	$3.00
Delivery	Nil	$0.13	$0.57	$1.20
Treatment/Disposal	$0.10	$0.22	$1.00	$4.28
Total	$0.10	$0.85	$2.82	$8.48

Power plant water costs are greater for wet-cooled plants, but they are neither zero nor necessarily negligible for plants equipped with dry cooling. First, there are numerous uses of water at plants in addition to main plant cooling. Depending on the type of plant these can range from 2% to nearly 10% of total plant water requirements. Also, several elements of the water-related equipment have fixed costs of equipment and installation plus those variable costs that are proportional to flow rate. Therefore, even the modest water use (diversion, withdrawal, or consumption) of a dry or hybrid cooled plant can incur water-related costs that are a larger fraction of those incurred at wet cooled plants than their relative water use quantities would suggest.

4.3.3 Other Plant Equipment

Other plant design features and their associated costs can be influenced by the choice of cooling system. For example, a plant designed for dry cooling would probably choose a turbine with the capability of tolerating higher backpressure. Additional discussion of this point is given in (EPRI, 2011b).

4.3.4 Cooling System Related "Penalty" Costs

A most important element of the comparative economics of alternative cooling systems is the influence that the cooling system has on plant efficiency and capacity. If, under the same ambient conditions, one cooling system results in a higher steam turbine backpressure than another, that system imposes economic penalties on plant operation. These penalties are categorized as either "heat rate" or "capacity" penalties.

Heat rate penalty costs are the result of degraded plant efficiency at higher turbine backpressures. These penalties can be incurred as higher fuel requirements (and cost) to maintain the same output by over-firing if the capability exists in the plant or in reduced output at the same firing rate.

Capacity penalty costs refer specifically to reductions in plant output necessary to keep the turbine backpressure below levels at which the turbine warranty is voided. These reductions occur only during the highest temperature hours of the year, but thus can coincide with the time when power system demand is the greatest and, in an unregulated market, the price for electricity is the highest. Therefore, the penalties can be severe, particularly at sites where temperatures are well above the annual average for many hours each year.

4.3.5 System Optimization

The basic steps in the procedure to optimize, compare, and select the preferred cooling system are the following:

- Specification of design point
- Cooling system design
- Determination of annual operating profile for competing designs
- Calculation of operating costs and penalties
- Aggregation of total annual cost (annualized capital + operating + penalty)
- Ranking of alternative cooling systems

4.4 Cost and Performance Comparisons of Cooling Systems for New Thermal Power Plants

Example comparisons[22] of annualized cost, annual plant output, and annual water use are presented for three plant types at five different sites, listed in Table 4-2, representing a range of climates across the U.S. Alternative cooling systems are configured and optimized for each site. Table 4-3 tabulates the results of the analyses as annualized cooling system cost, annual plant energy production, and annual water consumed through evaporation in the cooling systems. The same results are displayed visually in Figure 4-1 (coal-fired steam plants), Figure 4-2 (nuclear steam plants), and Figure 4-3 (gas-fired, combined-cycle plants).

[22] All of the costs categories defined above are highly site-, plant-, and company-specific. "Typical" values for fuel cost, power price, amortization rate, O&M practices, and other relevant factors are assumed consistently across all cases.

Table 4-2. Climate characteristics of selected sites.

Case No.	1	2	3	4	5
Climate Type	Arid, hot	Humid, hot	Arid, extreme	Moderate, cool	Moderate, warm
Location	Yuma, AZ	Jacksonville, FL	Bismarck, ND	Burlington, VT	St. Louis, MO
Elevation (feet)	207	30	1,660	341	564
Ambient Dry Bulb (^{o}F)					
Annual average	75	67.7	42.3	45.6	56.1
Summer average	80.2	78.5	65.4	65.5	69
Ambient Wet Bulb (^{o}F)					
Annual average	57.2	62.6	36.8	40.9	50.1
Summer average	59.3	70.6	55.3	56.9	60.6

Table 4-3. Summary of cooling system comparisons (annualized cost in millions; annual output; annual water consumption).

COAL-FIRED STEAM PLANT

Cooling	Yuma			Jacksonville			Bismarck			Burlington			St. Louis		
System	$	MWh	kgal	$	MWh	kgal	$	MWh	kgal	$	MWh	kgal	$	MWh	kgal
Wet	3.66	4.40	2.18	3.59	4.40	1.91	3.39	4.40	1.67	3.41	4.40	1.72	3.56	4.40	1.79
Dry direct	18.10	4.10	0	15.	4.19	0	11.6	4.21	0	11.7	4.20	0	13.6	4.20	0
Dry indirect	31.00	4.10	0	25	4.17	0	18.3	4.27	0	18.5	4.23	0	21.2	4.20	0
Hybrid	13.50	4.27	1.32	12.4	4.29	0.87	10.30	4.32	0.46	9.90	4.32	0.47	11.30	4.30	0.72

NUCLEAR STEAM PLANT

Cooling	Yuma			Jacksonville			Bismarck			Burlington			St. Louis		
System	$	MWh	kgal	$	MWh	kgal	$	MWh	kgal	$	MWh	kgal	$	MWh	kgal
Wet	4.66	5.21	3.49	4.7	5.19	3.05	4.39	5.23	2.64	4.42	5.23	2.74	4.62	5.22	2.66
Dry indirect	39.70	4.86	0	28.5	5.03	0	24.60	5.06	0	24.60	5.06	0	28.80	5.00	0
Hybrid	30.60	5.03	2.42	30.7	5.03	1.68	26.00	5.08	0.96	26.50	5.08	0.98	28.00	5.06	1.46

GAS-FIRED, COMBINED-CYCLE PLANT

Cooling	Yuma			Jacksonville			Bismarck			Burlington			St. Louis		
System	$	MWh	kgal	$	MWh	kgal	$	MWh	kgal	$	MWh	kgal	$	MWh	kgal
Wet	1.70	4.56	1.17	1.7	4.56	0.98	1.64	4.56	0.82	1.63	4.56	0.83	1.67	4.56	0.92
Dry direct	8.77	4.55	0	7.1	4.55	0	6.60	4.55	0	6.40	4.55	0	7.90	4.55	0
Hybrid	6.90	4.64	0.95	6.3	4.56	0.54	5.00	4.56	0.23	5.00	4.56	0.22	5.70	4.56	0.36

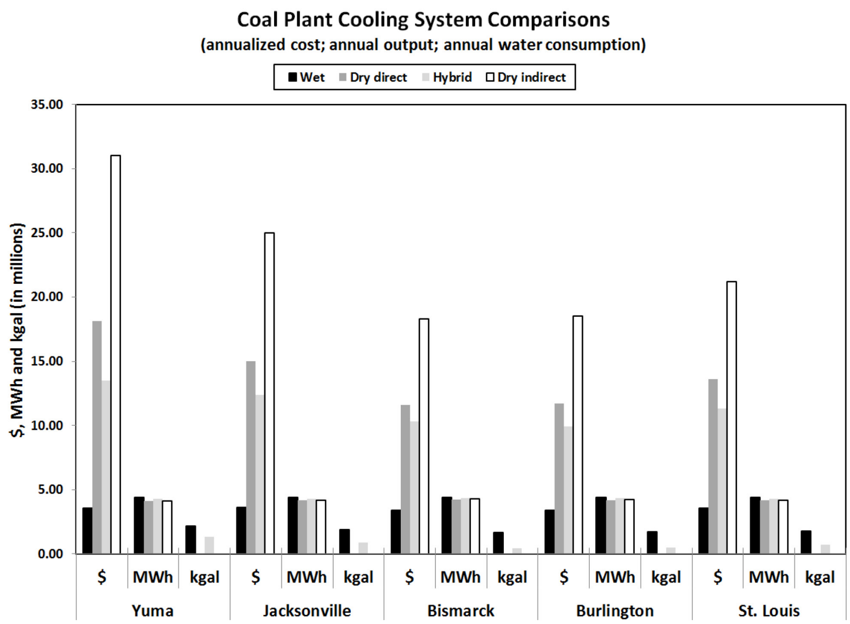

Figure 4-1. Cooling system comparisons for 500 MW coal plants.

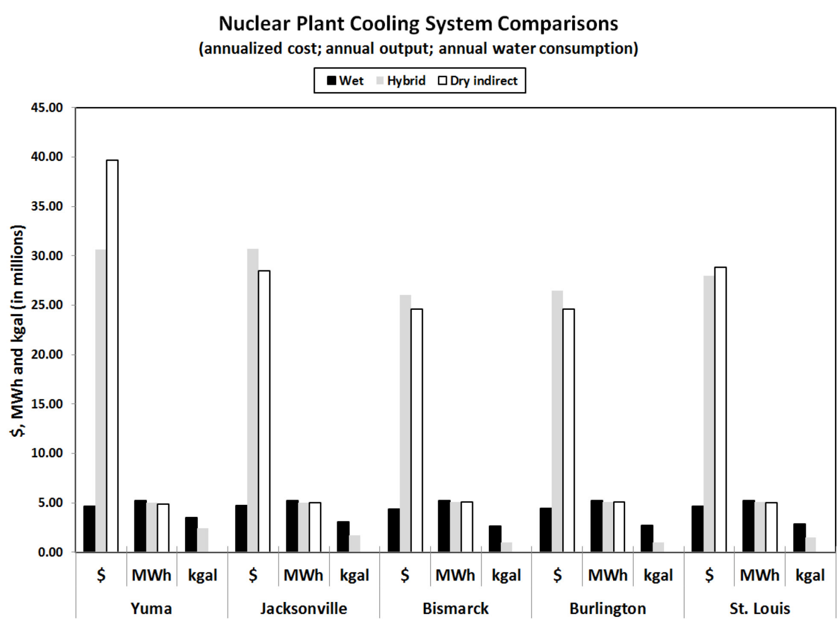

Figure 4-2. Cooling system comparisons for 600 MW nuclear plants.

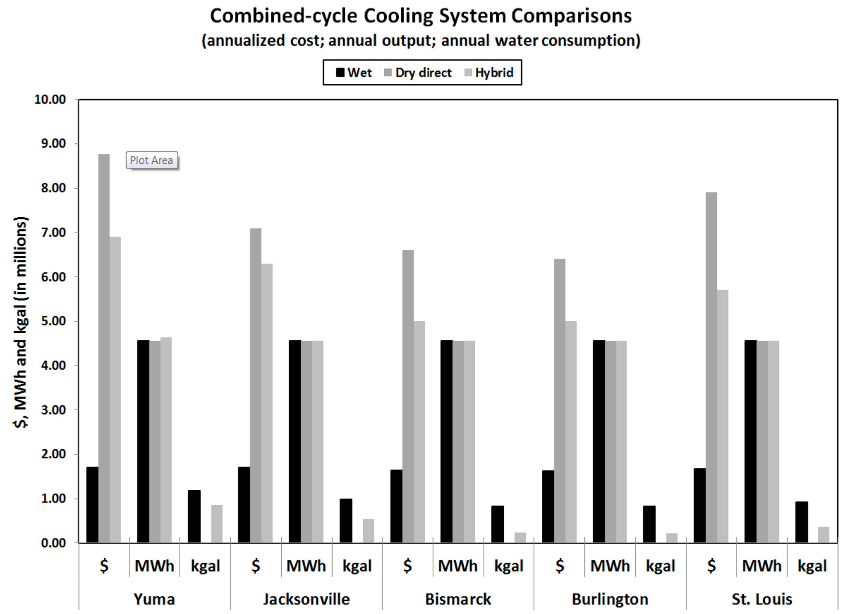

Figure 4-3. Cooling system comparisons for 525 MW gas-fired, combined-cycle plants.

4.4.1 Cost of Water Conservation

The use of either dry or hybrid cooling can result in a large reduction in the amount of water consumed by a plant. Depending on the plant design and the water required for uses other than cooling, the dry-cooled plant will save from 95% to 75% of the total water used by a wet-cooled plant. For the cooling alone, recirculating wet cooling at a 500 MW coal-fired steam plant consumes approximately 5,000 to 7,000 acre-feet per year. Dry cooling eliminates the need for cooling water and thus reduces plant water consumption by 5,000 to 7,000 acre-feet per year. The savings come at a cost of approximately $7 to $10 million per year depending on the meteorology at the site, which represents a cost of $1,000 to $2,000 per acre-foot of water saved, implying a breakeven water cost of $3 to $6 per thousand gallons. As a comparison, this cost of water is relatively high and comparable to that for municipal water (Walton, 2010).

4.5 System Economic Studies of Cooling System Retrofits

The issue of retrofitting existing cooling systems has received current attention because of regulatory activity at both state and national levels, which may require the retrofit of once-through cooling systems to reduce withdrawals from natural water bodies (EPA, 2002b).

The Electric Power Research Institute (EPRI) conducted five integrated studies (EPRI, 2011a; EPRI, 2011c; EPRI, 2011d; EPRI, 2011e; EPRI, 2012b)[23] in the context of the 316(b) Phase II Rulemaking on cooling system intake environmental effects. EPRI estimated that there were 428 facilities subject to retrofit requirements based on their use of greater than 50 million gallons per day (MGD) of once-through cooling water. These facilities represent approximately 312,000 MW of generating capacity, including 80,000 MW from 39 nuclear facilities and 252,000 MW from 389 fossil plants. While closed-cycle cooling significantly reduces impingement mortality of fish and shellfish on cooling water intake structure screens as well as entrainment mortality of the early life stages of fish and other aquatic organisms from passage through the condenser cooling water system, these systems can produce a variety of potentially adverse related effects. Some of these potentially adverse effects are fine particulate emissions, visible plumes of water vapor, salt deposition, icing (due to water vapor plumes falling onto roads and freezing during winter), and noise. Further, because the heat rates slightly increase for power plants with closed-cycle retrofits, a marginal analysis will indicate higher flue gas air emissions (e.g., NOx, SOx, CO_2, Hg) per MWh of output. The EPRI studies, in addition to estimating the national cost of closed-cycle retrofit on all potentially eligible facilities, address the external costs and benefits, the effect on the overall power network, and some issues specific to nuclear plants.

The EPRI studies estimated impacts on human health, terrestrial and aquatic resources, solid waste and public safety, security and quality of life, as well as the permitting issues associated with these impacts. Evaluations were made at 24 sites. The impacts were quantified and monetized to the extent possible. The effects were found to be site-specific and a function of the water body type, adjacent land use, fuel type, and nearby population density. Potential effects on human health, terrestrial and social resources, noise, viewshed degradation, and safety were dominant in urban and suburban areas; terrestrial, ecological, and agricultural impacts were dominant in rural or undeveloped areas. Excluding the effects of increased greenhouse gas emissions and effects on human health at most of the 24 sites, the monetized impacts of closed-cycle cooing retrofits were found to exceed the benefits of reduced fish mortality from impingement and entrainment (EPRI, 2011a; EPRI,

[23] These EPRI reports are available online at no charge by inserting the report number into the search field of the EPRI website: www.epri.com.

2011b). However, the monetization of both the impacts and benefits has considerable uncertainty and methods for monetization of some of the impacts and benefits are unavailable.

Two complementary studies dealt with the financial impacts (EPRI, 2011c) and the transmission system impacts (EPRI, 2011d) of closed-cycle retrofits on the larger electric power system. The financial impact study addressed the specific question of which plants would choose retirement as a result of the increased costs imposed by a cooling system retrofit. Information on unit-specific capacity utilization over a five-year period was combined with unit-specific capital cost estimates and unit-specific reductions in efficiency and capacity from the retrofit costs study (EPRI, 2011a) in a model which simulates the economic factors that underlie the wholesale electricity markets. The combination of the imposed capital and operating costs made retrofitting economically infeasible in the case of some plants with low capacity factors and short remaining life. Approximately 26,000 MW of fossil plant capacity was deemed to be at risk of premature retirement.

Results from the study were examined in five NERC regions (PJM, ERCOT, ISO New England, NYISO, and Midwest ISO). The potential capacity reductions from retirement and capacity reduction penalties were coupled with forecasts of new generation in each of these five regions to assess power system adequacy in light of target reserve margins in the regions. Also, security-constrained optimal power flow simulation methodologies were used to identify thermal overloads and voltage violations. Potential generation and transmission system enhancements were identified.

The analyses estimated that premature retirements resulting from system retrofits posed little risk to generation adequacy in the PJM and Midwest Independent System Operator (ISO) regions, but, in the ERCOT, ISO New England and NYISO regions an estimated $7 billion of 8.7 GW[24] of new capacity would be required to maintain adequate reserve margins. This amount of money was estimated to be the lesser of (i) the amount required to offset all the regulation induced capacity loss; or (ii) the amount required to reach the projected 2016 target capacity margins for each of the three ISO regions.

[24] The cost of capacity was estimated based on the fixed cost of replacement generation in the form of combustion turbines at approximately $800/kW.

In all regions, some transmission system enhancements would be required to avoid some local thermal overloads and voltage violations.

4.5.1 Retrofit Cost Methodology

While the problems and associated costs are highly site-specific, some general conclusions can be stated. A methodology was developed and applied to estimate the aggregated national cost if all units currently using once-through cooling were retrofitted with closed-cycle wet cooling using mechanical-draft wet-cooling towers (EPRI, 2011a). Retrofitting once-through or wet-cooling systems to dry or hybrid cooling can be shown to be technically and economically infeasible in nearly all cases and will not be discussed further here (EPRI, 2011b; EPRI, 2012b).

Dry cooling of either type was not considered in the EPRI studies for several reasons. First, given that closed-cycle wet cooling typically reduces the water withdrawn for cooling by 93% to 98 % of that required for once-through cooling, the use of dry cooling would represent only a small, incremental further reduction in water intake rates. However, dry systems, in essentially all situations, are far more costly, require significantly more operating power, and impose significantly higher efficiency/capacity penalties on the plants than is the case for wet systems. An engineering study of a California coastal plant (Sargent and Lundy, 2005) showed a doubling of the capital cost and a tripling of the operating/energy penalty costs for dry cooling in comparison to wet cooling. In addition, the physical size of air-cooled equipment occupies four to six times the land area and is two to three times higher than a corresponding mechanical-draft, wet-cooling tower, exacerbating the siting problem at existing plant sites.

Finally, the output limitation on hot days, which normally coincide with days of highest demand for power, would be unacceptable with turbines originally designed for use with once-through cooling with a typical backpressure limitation of 5 inches Hga[25]. The use of dry cooling for retrofit in many situations would require turbine replacement with turbines capable of operation at higher backpressure as are used on new plants designed for dry cooling. The additional cost and the duration of plant downtime for such an extensive re-optimization and retrofit are unknown, but would clearly significantly exceed the costs and duration of the more usual retrofit from once-through to wet-cooling towers. The

[25] inches Hga = inches of mercury absolute pressure

disadvantages are particularly significant for nuclear plants that suffer higher penalties with increased turbine exhaust pressure and are typically base-loaded.

The conclusion to exclude dry cooling from further consideration and discussion for thermal plant cooling system retrofit is consistent with those of other studies on the subject, including the TetraTech study (TetraTech Inc., 2008) for the California Ocean Protection Council and the work of EPA in the development of the original Phase II rule (EPA, 2004).

The methodology for estimating once-through to wet-cooling towers consists of three steps:

1. Step 1 establishes a likely range of capital costs for a plant as a function of the circulating water flow rate in the original once-through cooling system. Separate correlating equations describe fossil and nuclear plants.
2. Step 2 places an individual plant cost within the likely range of costs on the basis of the perceived degree of difficulty of a retrofit at that plant. The degree of difficulty is based on site-specific information obtained from a cost-estimating worksheet survey of over 185 facilities. Estimates are made for approximately 125 facilities to create a cost distribution for the family of Clean Water Act 316(b) Phase II facilities[26] (see Chapter 2) over a range of degrees of difficulty from "Easy" to "More Difficult" (for fossil plants) and "Less Difficult" to "More Difficult" (for nuclear plants). For those sites judged to be intermediate between any two of the four degrees of difficulty the average of the two bounding categories was used.
3. Step 3 estimates the national costs by applying the cost vs. flow rate correlations for fossil and nuclear plants to the full family of Phase II plants listed in Table 4-5. The full family of plants was assumed to be distributed across the range of degrees of difficulty in the same proportion as was determined for the 125 plants analyzed in Step 2.

[26] Phase II facilities are cooling water intake structures at existing steam electric power plants that commenced construction on or before January 17, 2002, and that withdraw more than 50 million gallons per day (MGD) from waters of the United States

In addition, estimates were made of three other significant cost elements. They were the cost of energy replacement during the time a plant is down for retrofitting, the annual cost of additional operating power, and the annual cost of the heat rate penalty resulting from thermal limitations of the closed-cycle cooling system. Estimates of the downtime duration for nuclear and fossil plants were based on a limited number of independent engineering studies for nuclear plants and information from a few actual retrofits at fossil plants.

4.5.2 Degrees of Difficulty of Once-Through to Wet-Cooling Tower Retrofits

After observing the wide variation in cost for retrofitting plants of comparable size, it was concluded that the low, mid-range, and high costs corresponded, in a general way, to the degree-of-difficulty categories of "Easy," "Average," and "Difficult" discussed above.

Based on discussions with plant personnel and architect-engineering firms, as well as application of professional judgment, the list of 11 factors given in Table 4-4 was compiled; these factors were believed to be the important influences that determine the site-specific degree of difficulty. Note that these factors influence the difficulty and complexity, and hence the cost, of retrofitting closed-cycle cooling onto a plant designed for, built with, and operating on once-through cooling at a given site. The factors are not meant to relate to a change in either the withdrawal or consumption of cooling water.

Table 4-4. Factors influencing degree of difficulty of once-through to wet-cooling tower retrofits.

Factor	Description
1	The availability of a suitable on-site location for a tower
2	The separation distance between the existing turbine/condenser location and the selected location for the new cooling tower
3	Site geological conditions, which may result in unusually high site preparation or system installation costs
4	Existing underground infrastructure, which may present significant interferences to the installation of circulating water lines
5	The need to reinforce existing condenser and water tunnels
6	The need for plume abatement
7	The presence of on- or off-site drift deposition constraints
8	The need for noise reduction measures
9	The need to bring in alternate sources of makeup water, such as treated municipal discharge, if the once-through cooling source water is unsuitable for use in cooling towers.
10	Any related modifications to balance of plant equipment, particularly the auxiliary cooling systems, that may be necessitated by the retrofit
11	Re-optimization of the cooling water system or extensive modification or reinforcement of the existing condenser and circulating water tunnels

Table 4-5. Capacity and water flow rates at Phase II facilities.

Plant Type	Number of Plants	Total Capacity	Total Circulating Water Flow
		MW	gpm*
Fossil	389	252,391	139,506,944
Nuclear	39	59,931	42,788,889
Total	428	312,322	182,295,833

* gpm = gallons per minute

4.5.3 Cost Ranges for Cooling System Retrofits

Independent information on actual and estimated retrofit costs at over 80 plants yielded likely ranges of costs for individual plant retrofits as a function of cooling water flow rate. Separate equations in the form of Equation Eq. (4-1) were developed for fossil and nuclear plants and are tabulated in Table 4-6.

$$C_{rf} = K_{dd} \cdot W_{circ} \qquad \text{Eq. (4-1)}$$

where C_{rf} is capital cost of retrofit, \$, K_{dd} is retrofit cost coefficient (see Table 4-6), and W_{circ} is circulating water flow, gpm (gallons per minute). Table 4-7 shows the U.S.-wide aggregated results for Phase II cooling system retrofits.

Table 4-6. Normalized cost coefficients for cooling system retrofit cost estimates.

Degree of Difficulty	Retrofit Cost Coefficient ($/gpm)*
Fossil Plants	
Easy	181
Average	275
Difficult	405
Most Difficult	570
Nuclear Plants	
Less Difficult	274
More Difficult	644

*gpm = gallons per minute

Table 4-7. National costs for all Phase II plants categorized by source water type (units in millions 2010 U.S. dollars).

Plant Type	Source Water	Capacity	Once-Through Water Flow Rate	Costs ($2010 millions)					
		Capacity	Once-Through Water Flow Rate	Capital **	Operating Power*	Heat Rate Penalty*	Downtime **	Annualized*	Net Present Value**
		MW	MGD						
Nuclear	Fresh River	11,797	10,575	$3,371	$28	$30	$1,808	$420	$5,898
Nuclear	Lake/Reservoir	19,917	20,145	$6,421	$47	$51	$3,053	$761	$10,688
Nuclear	Great Lakes	6,177	5,530	$1,763	$14	$16	$947	$220	$3,086
Nuclear	Ocean, Estuary, Tidal River	22,040	25,366	$8,085	$52	$57	$3,379	$991	$12,808
Nuclear	Other	0	0	$0	$0	$0	$0	$0	$0
Nuclear	Total Nuclear	59,931	61,616	$19,640	$141	$154	$9,187	$2,312	$32,480
Fossil	Fresh River	93,952	72,640	$16,116	$172	$127	$5,51	$1,813	$25,341
Fossil	Lake/Reservoir	61,470	47,276	$10,489	$113	$83	$3,605	$1,182	$16,524
Fossil	Great Lakes	26,853	20,509	$4,550	$49	$36	$1,575	$514	$7,187
Fossil	Ocean, Estuary, Tidal River	70,020	60,369	$13,394	$128	$95	$4,106	$1,448	$20,269
Fossil	Other	96	96	$21	$0.2	$0.1	$5.6	$2	$31
Fossil	Total Fossil	252,391	200,890	$44,570	$463	$341	$14,802	$4,960	$69,352
	Total Phase II	312,322	262,506	$64,210	$604	$495	$23,989	$7,273	$101,833

*Annualized in millions 2010 U.S. dollars per year

**Net Present Value in millions 2010 U.S. dollars

4.5.4 *Nuclear-Specific Issues*

One study considered characteristics of nuclear plants and their cooling requirements that had particular relevance to retrofits that differ from those at typical fossil plants (EPRI, 2012b). In general, the normalized capital costs of retrofit (expressed in $/gpm of cooling water flow) were consistently higher for nuclear plants than for fossil plants. This result stems primarily from space constraints, which are typically more severe at nuclear plants due to safety and security considerations. Also, for nuclear turbines with lower turbine inlet pressure and temperature, there are larger efficiency and capacity reductions resulting from increases in cooling water temperature and turbine exhaust pressure. Additionally, there are a number of safety-related cooling requirements at a nuclear plant (see Section 3.5), such as emergency core cooling, ultimate heat sink capacity, spent fuel pool cooling, and control room conditioning that dictate a maximum allowable cooling water source temperature below some level determined at the time of plant design, construction, and permitting. If the retrofitted closed-cycle cooling system cannot deliver these cold water temperatures during some periods, plant shutdown may be required.

4.5.5 *Examples of Thermal Power Plants That Have Retrofitted Once-Through Cooling Systems*

There are very few examples of once-through cooled plants retrofitting to closed-cycle cooling. Seven, for which some information is available (TetraTech Inc., 2008), are:

1. Canadys (South Caroline E&G)
2. Jeffries (Santee Cooper)
3. McDonough (Southern/Georgia Power)
4. Palisades Nuclear Generating Station (Entergy)
5. Pittsburg Unit 7 (Pacific Gas & Electric)
6. Wateree (South Caroline E&G)
7. Yates (Southern/Georgia Power)

Of these seven plants, six are fossil plants; one, Palisades, is a nuclear plant. Palisades was commissioned in 1971 and operated on once-through cooling for the first year or so and switched over to cooling towers in 1973. The reason for converting from once-through to closed-cycle cooling is reported to be local environmental concern over thermal discharges and potential “radioactive releases from the radwaste system” and unrelated to intake issues (TetraTech Inc., 2008). Anecdotal information suggests that the decision to go to closed-cycle cooling was made during the last phases of construction, but operation was allowed to begin on once-through cooling while the closed-cycle capability was being installed. The cost, in 1971 dollars, is reported to be $18.8 million.

At the six fossil plants, to our knowledge, none of the retrofits was motivated by intake issues but either by thermal discharge or water supply considerations. Brief discussions of all the plants with the exception of Wateree are available (TetraTech Inc., 2008). Brief summary information on McDonough and Yates follows.

Plant McDonough is a two-unit, coal-fired plant. Both units are 270 MW for which the cooling withdrawal rate prior to retrofit was 135,000 gpm for each unit. Each unit was retrofitted with a 10-cell, counterflow, mechanical draft cooling tower. The towers were in-line towers of the plume-abatement type. The total retrofit project lasted approximately 3 years; 1 to 1½ years in design; 1½ to 2 years in demolition, construction, tie-in, and startup. Most of the construction was accomplished with the plant online. The tie-in outages took 8 weeks for Unit 1 and 10 weeks for Unit 2. The additional pump and fan power was about 3 to 5 MW. While the annual average turbine backpressure was expected to be slightly higher than it had been on once-through cooling, the hot summer performance was actually expected to be slightly better due to the high river temperatures in the summer.

Plant Yates is a five-unit, coal-fired plant (Units 1, 2, and 3—100 MW; Units 4 and 5—125 MW). A single, 40-cell, counterflow, mechanical-draft tower in a back-to-back arrangement was installed to handle all five units (segmented so there are 8 cells per unit). The tower was designed to deliver 86°F cold water at a design wet-bulb temperature of 80°F. This would actually provide a slight improvement over once-through cooling on the hot days due to the high river water temperature in the summer. The tie-in was done in two outages of 9 weeks for Units 1 and 2 and 5 weeks for Units 3, 4, and 5. The project cost was estimated at under $100 million.

4.6 Economic Benefits of Alternative Cooling Technologies

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Technology alternatives to open-loop cooling can present economic benefits to power plants despite the associated additional costs (see previous section of this chapter). The lower water withdrawal requirements of such cooling technologies leave power plants less vulnerable to the risk of water supply disruption constraints from natural phenomena (e.g., droughts and heat waves) and policy measures (e.g., thermal pollution limits; see Sections 2.2 and 2.3). Below is an overview of a methodology for quantifying the economic benefits associated with low-water cooling technologies; see (Stillwell and Webber, 2013) for further details and an application of the methodology.

4.6.1 Value of Resiliency Against Water Constraints

While recirculating, hybrid wet-dry, and dry-cooling systems typically cost more than comparably sized open-loop cooling systems, these technologies require less water withdrawal (but increased water consumption). The decreased water withdrawal requirements mean alternative cooling technologies have the added benefit of resiliency against water constraints. That is, since cooling towers, cooling reservoirs, hybrid wet-dry, and dry-cooling systems withdraw less water, those power plants are less likely to suffer curtailment or shutdown as a result of lack of water.

Being able to generate electricity when open-loop power plants might curtail or shut down operations has value that can be quantified economically. The annual benefit (A_b in \$/yr) associated with the value of resiliency against water constraints is:

$$A_b = \theta \sum_{\text{all n}} p_{f,n} C_n r G \qquad \text{Eq. (4-2)}$$

where θ is the risk aversion factor ($\theta = 1$ as risk neutral, $\theta < 1$ as risk averse, and $\theta > 1$ as risk seeking), p_f is the probability of a specific water constraint event n, C is the power generation curtailment [%] associated with an event n, r is the electricity sales rate [\$/MWh], and

G is the annual plant generation [MWh/yr] [adapted from (Stillwell and Webber, 2013)]. The factor $\sum_{\mathbf{all\ n}} p_{f,n} C_n$ represents the expected value of the given water constraint event occurring in any given year (expected value calculations are common in statistical practice). For example, if the value of $\sum_{\mathbf{all\ n}} p_{f,n} C_n$ was 0.08 for drought-related power generation curtailment, the expected value of curtailment in any given year is 8%. The actual value of drought-related curtailment might be higher or lower in various years, but the expected value represents the level of occurrence on average.

Different power plants have different physical and natural conditions, making p_f and the associated C unique to each individual plant. To determine susceptibility to drought, a power plant might use historical drought records or drought indices [such as the Palmer Drought Severity Index, PDSI; see (NCDC, 2011)] to estimate the probability of drought conditions. Then the level of operational curtailment associated with a given drought condition (of probability p_f) could be estimated from historical records such that a power plant could estimate the expected value of drought-related curtailment in any given year, $\sum_{\mathbf{all\ n}} p_{f,n} C_n$.

Similarly, the risk aversion factor θ might be unique to an individual power plant. Public relations, economic conditions, and business management approaches might allow different amounts of risk in power generation operations, changing the value of θ. For example, a nuclear power plant might set $\theta < 1$ for safety reasons, while a natural gas combined-cycle or peaking unit might set $\theta > 1$ to maximize profits. Application of Equation Eq. (4-2) to a given power plant allows flexibility for such site-specific nuances.

4.6.2 Insurance Against Water Constraints

The benefits of alternative cooling technologies can be considered a form of insurance against water constraints such as droughts and heat waves. As described in Sections 4.1–4.5, alternate cooling technologies can incur parasitic losses in the form of heat rate and capacity penalty costs. Yet these penalty costs represent a trade-off in terms of vulnerability to water supply constraints. While there is a low probability of a drought completely shutting down a wet-cooled power plant, lost electricity sales are extremely high if the circumstances arise. Use of alternative cooling mitigates the likelihood of extreme curtailment or shutdown, but at the expense of lower near-constant parasitic losses.

This concept is similar to fire insurance for homeowners. There is a low probability of a house being completely destroyed by fire, incurring significant expenses; however, fire insurance covers the damage associated with the event in exchange for an annual premium. In the case of dry cooling, a power plant pays an annual premium of heat rate and capacity penalty costs in exchange for being able to produce electricity during a drought or heat wave when other wet-cooled power plants might be legally (e.g., see Section 2.2 regarding *CWA §316*) or technologically forced to shut down.

4.6.3 Applicability to Retrofit and New Construction

Assigning economic benefits to alternative cooling technologies is applicable to both retrofit of existing power plants and new construction. Limited data exist regarding retrofit of alternative cooling technologies, especially regarding installation of dry cooling. The additional flexibility of the annual benefits in Equation Eq. (4-2) is that the calculation is suitable for both circumstances. While a new construction facility would not have historical data on curtailment associated with water constraint events, these data could be predicted based on temperature and/or lake-level models and the effect of water conditions on power plant operations. Since predicted circumstances for a new construction power plant include a certain level of uncertainty, a facility might be slightly more risk averse (i.e., higher value of $\boldsymbol{\theta}$) to account for possible errors.

The method highlighted here allows a power plant to assign monetary benefits to water withdrawal reductions associated with operation of alternative cooling technologies. Depending on plant-specific circumstances, the possible benefits associated with resiliency against water constraints might (or might not) exceed the additional cost of heat rate and capacity penalties.

4.7 Nomenclature

ACC	Air-cooled condenser
ACHE	Air-cooled heat exchanger
CWA	Clean Water Act
gpm	Gallons per minute

inches Hga	Inches of mercury, absolute
kgal	Thousand gallons
MGD	Million gallons per day
MW	Megawatt
MWh	Megawatt-hour
PDSI	Palmer Drought Severity Index

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5 Cooling System Case Studies

5.1 Various Case Studies

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Alstom Power

Thermal power plants using a water steam cycle require water for many purposes: preparation (commissioning); operation, during which makeup water is needed to compensate for the cycle losses; and potentially also cooling, in case of open circuit (river water direct cooling) or wet-cooling towers (either natural or forced draft).

In most cases, thermal power plant design is directly impacted by availability of water, or rather, unavailability. For the cooling needs of a significant number of power plants, “zero water consumption systems” (i.e., Air Cooled Condensers, or ACCs) are selected because there is no other viable cooling alternative on site. In such context, there is no optimization or cooling system comparison to be made: only one cooling process applies and all other water consumption, such as for boiler water cycle makeup, represent a challenge, and at the end of each day, a cost. These necessary deployments of ACCs represent the most extreme context in terms of designs for low water availability.

5.1.1 Argentina—ACC Instead of Once-Through Sea Water to Avoid Disturbed Habitat for Coastal Tourism

Usually there is water “within reach” for power plant use but, however, not used for plant cooling. Alstom built, for instance, two combined cycle power plants for the Aluar aluminum-producing company in Argentina. The plant is located north of Puerto Madryn harbor in Chubut province, with easy nearby access to the deep-blue Golfo Nuevo and Atlantic Ocean, which represent an abundant source of cold water likely to enable a high-performance once-through cooling cycle. In spite of this thermodynamically favorable context, it was specified from the early stages of both projects that no access to this large and stable cold end would ever be allowed—ACC was mandatory. The reason is that a significant part of the income of Puerto Madryn city rises from tourism, and large whales taking shelter in Golfo Nuevo six month per year might dislike the warmer water that would be discharged from a once-through design. Open circuit (or once-through) cooling, in spite of thermodynamic and economic advantages, is therefore a clear no-go, and large groups of tourist still enjoy the vision of the largest living animals on this planet.

5.1.2 ACC to Avoid Visible Plumes

In many other power plant locations, sea or even fresh water is available, but nevertheless dry-cooling systems were selected for the cooling systems.

There was a time some decades ago when the impact of power plants on surrounding areas, not to mention the environment more globally was more or less ignored. Coal-firing plants were emitting a dark and thick plume, distributing particulates miles around the stack, and this was more or less admitted. Nowadays, and this is a worldwide trend, laws restrict emissions of NOx, SOx, CO, particulates, etc. This was an initial effort to push manufacturers toward environmental-friendly solutions. A further step was taken more recently including requests to reduce visual impact of power plants on the environment.

The modern regulatory situation is significantly different and nowadays, permits are released based upon real commitments from both operators and EPC (engineering, procurement, and construction) contractors in all kind of environmental concerns. In many power plant project public presentations a complete folder informs about the future appearance of the plant even prior to construction, with some visible effort in virtual imagery integrated with current site real photography. As an example, for the Carrington Power plant site the discretion of the plant was a concern[27]:

> "Carrington Power has been designed to minimize the visual impact on its surroundings. Physically, the plant comprises two elements: the main power station buildings and two chimney stacks. There will be no visible plumes from the plant's chimney stacks under normal operations. Particular attention will be paid to the visual appearance of all buildings and discreet colour schemes will be chosen to blend in with the surroundings. Tasteful landscaping will further reduce any visual impact."

[27] See http://www.carringtonpower.co.uk/location/

Focusing on power plant plumes more specifically, there are two main categories of visible plume:

- Combustion products: Visible plumes can be soot, particulates, and, depending on the fuel, a non-negligible amount of water rising from combination of "-C_xH_y" chains with O_2 from combustion air. It is to be noted that flue gas from gas turbines firing natural gas is highly visible—and white—in freezing conditions. Visible combustion products do not occur only in the case of coal or heavy fuel fired plants, as in some conditions, gas turbines also might generate colored flue gas.

- Water mist plume coming from cooling towers: Either natural (frequently installed on nuclear power stations or large steam plants) or forced draft cooling towers (that are often used on combined cycle plants) cool the thermal power plant steam cycle by partial evaporation of water steam. In many cases, the exhaust air at the outlet of the cooling towers is very close to saturation and once in atmosphere generates highly visible plume.

It is worth mentioning that some recent coal or lignite-fired power plants—for instance, Belchatow in Poland—are designed in such a way that the boiler exhaust duct (i.e., downstream flue gas treatment plant) is located in the middle of the natural draft cooling tower. Besides the slight draught advantage, the design visually departs from the traditional high chimneys that are no longer welcomed in some countrysides.

The Baudour/Saint Ghislain natural gas combined cycle in Belgium, owned by Tractebel, is one example of a power plant that uses dry cooling to avoid visible plumes. There is water available in a nearby channel, located about 100 meters away from the machine room, and a previous plant on the site used a large natural draft wet-cooling tower. However, an ACC was selected in order to improve the visual impact of the power plant on the area: instead of the previous large tower with large visible plume, a lower-level ACC was installed, carefully hidden behind a row of trees.

5.1.3 North Africa—ACC Instead of Nearby Brackish or Sea Water

ACCs may also be selected due to a risk analysis outcome. In the specific case of a project near a large laguna in northern Africa, an ACC was selected in spite of access to brackish water, as well as access to open sea water within a few kilometers range. The primary reason for using an ACC was environmental: to prevent the use of laguna water for wildlife protection purposes. Further, in considering sea water cooling, the civil engineering assessment concluded that there were higher risks and costs associated with constructing and operating two long ducts for the large flow of cooling water than when using a standalone ACC on site. The concerned parties agreed the proposition is wise and appropriate; further steps now depend on the decision to be taken at the time of this writing.

5.2 Drought and Water for Energy in Australia

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Australia, like the United States, is substantially dependent on fossil fuel–powered thermal generators for its electricity supplies: 77% of the nation's electricity is generated from coal (NWC, 2012). Major portions of Australia are water scarce. Nearly 90% of water diverted from the nation's rivers and aquifers is for irrigated agriculture, but there is enough water nationally to support wet-cooled thermal power generation. However many thermal power plants are either in dry regions or are concentrated in particular river basins where water is limited, such as in the Hunter Valley region of New South Wales and the Latrobe Valley region of Victoria (NWC, 2012; Smart and Aspinall, 2009).

A mandatory renewable energy target is driving increased supply from intermittent solar and wind generators. The Australian carbon tax, commenced in July 2012, is scheduled to evolve into an emission-trading scheme from 2015 for a 5% emission reduction target by 2020 (Australian Government, 2011). Early reports indicate that these policies are reducing the share of coal-fired electricity generation on the eastern Australian grid (Hannam, 2013).

Together with increased supplies of natural gas, an equal increase in energy generation is likely to come from gas fired peaking power stations. While circumstances have changed in many respects, a 2008 assessment suggested that to meet demand plus a 10% carbon emission reduction target by 2020 there could be 1,304 MW more coal or gas-fired steam turbine capacity, plus 6,520 MW capacity from natural gas combined cycle systems (NWC, 2012; Smart and Aspinall, 2009). Aspirational proposals for large, concentrated solar, or geothermal energy generation in arid areas of Australia may place further demands on water resources (BZE, 2010; RPS Aquaterra and Hot Dry Rocks, 2012).

Governance of minerals, water, and electricity are primarily the responsibility of state governments in Australia, although electricity and water laws have been largely harmonized under policy agreements between the federal and all state governments. Under the 2004 Australian National Water Initiative, the federal and all state governments agreed that the volume of water allocated from each aquifer or river basin would be capped (Commonwealth of Australia et al., 2004). If this plan were fully implemented, all major water users would be required to hold tradable water rights that are a share of the available water resource. Thus, each year state government water authorities would determine that overall share of available water, and then for each water right holder, the share of their water entitlement they can take that season depending on the level of security afforded to their water right (the security levels are usually categorized as "high" or "general"). This system contrasts with the prior appropriation and riparian doctrines of water laws in the U.S. (Grafton et al., 2011). This market was designed to enable water entitlements to be readily sold by low value users to high value users permanently or as short-term trades for adaptation to drought. While substantially implemented in the agricultural sector with positive socio-economic outcomes, in a number of instances power producers remain outside the cap and trade water market system (NWC, 2011).

During the severe drought afflicting southern Australia from 2002 to 2010, water shortages in dry regions (e.g., Hunter Valley of New South Wales, Latrobe Valley region of Victoria) threatened security of power supply and resulted in requests from generators to state governments for diversion of environmental water for power plant cooling (Marsh, 2009). Environmental water is "to protect and restore the environmental assets" and environmental water requirements are defined as: "descriptions of flow regimes (for example, volume, timing, seasonality, duration) that are needed to sustain the ecological values of aquatic ecosystems, including their processes and biological diversity, and that are designed to provide environmental outcomes" (NWC, 2011)[28]. While the breaking of this drought pre-empted a decision on diverting environmental water flows for power plants, changes in the electricity sector in Australia mean that water use for power plant cooling remains an issue of concern (Newell et

[28] (NWC, 2011, p. 38, 348)

al., 2011). The choice to use technology that limits water withdrawal and consumption at the Kogan Creek Power Station sets a key precedent in this context.

5.2.1 Air-Cooling Kogan Creek Power Station

The Kogan Creek Power Station is situated near the town of Chinchilla, 280 km northwest of Brisbane in the state of Queensland. Owned by CS Energy (a state-owned enterprise), Kogan Creek is a 750 MW supercritical coal-fired station operated to provide base load power. Built from components supplied by Siemens and Babcock Hitachi, its construction began in 2004 and the AUD $1.2 billion[29] station was commissioned in 2007 (CS Energy, 2008; Siemens, 2008; Siemens, 2010).

The Queensland Government approved the power station based on the choice of dry-cooling technology to reduce water consumption by 90% compared to wet-cooling systems, to around 1,500 million liters per year, or 250 to 300 L/MWh (66 to 79 gal/MWh) (Blackaby, 2006). Chinchilla has an average annual rainfall of 670 mm. Droughts are frequent in Australia and are anticipated to occur more often with climate change (Pittock, 2009). At the Tarong coal-fired power station, a hundred kilometers from Kogan Creek, three of the four units had to be shut down in March 2007 due to water shortages (Marsh, 2008; Siemens, 2008).

The Kogan Creek power station is located in a dry region close to coal deposits and draws on aquifers for cooling water. This water is sourced from the Lagoon Gully Bores located 26 kilometers south of the station and the Kogan Bore near the power station (CS Energy, 2008). The Kogan Creek cooling system uses an air-cooled condenser (only the second power plant using the technology in Queensland) consisting of 48 fans, each with a diameter of 9 meters, supplied by the GEA Group of Germany (CS Energy, 2008; Harten, 2008). Water can also be sprayed beneath the condenser surfaces for additional cooling so that the plant can operate at full capacity even at temperatures over 40°C (Siemens, 2008; Siemens, 2010).

The plant is designed for an efficiency rating of 45% (lower heating value, LHV)—comparable to water-cooled facilities—that Siemens claims is one of the highest in the world for a dry-cooled plant. Siemens

[29] AUD $1.00 = ~ USD $1.03

describes Kogan Creek as the most efficient coal-fired power plant in Australia (Siemens, 2008). An estimate of real-world operational efficiency of Kogan Creek is 37.5% (at higher heating value, HHV) (ACIL Tasman, 2009).

5.2.2 Kogan Creek Solar Boost Project

In 2011 construction started at Kogan Creek on an additional project to integrate solar energy with the coal-fired power station, touted as the largest such integrated generator in the world when it becomes operational in 2013 (CS Energy, 2011). The project involves the installation of a 44 MW solar thermal addition to the plant using AREVA Solar's compact linear Fresnel reflector technology to supply additional steam to the turbine, supplementing the coal-fired steam generation process.

Funding for the project includes $70 million from CS Energy but also relies on grants of $34.9 million from the Australian Government's Clean Energy Initiative and $35.4 million from the Queensland Government. The integration of the solar technology at the power station will save 35,000 tons of greenhouse gas emissions per year (CS Energy, 2011).

5.2.3 Conclusion: Australia Case Study

Kogan Creek demonstrates that it is viable to use dry-cooling technology in a major power station to conserve water in regions subject to scarcity. This may be a technology that enables greater deployment of thermal power stations in arid areas.

5.3 Regulatory Frameworks and Incentives for Australian Power Plants to Adopt Water Efficiency Measures

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Despite structural and institutional barriers, water security—in relation to both availability of supply and quality—has begun to be regarded as a business risk by some energy sector managers in Australia. During the 2002–10 Australian drought, reductions in the availability of Australia's hydroelectric capacity resulted in higher wholesale electricity prices, as more expensive gas-fired generation was required to replace hydroelectricity's usual backstop generator role. While critical levels were never reached, availability of cooling water reserves for thermal generators became a material risk in some regions (Smart and Aspinall, 2009). Thus, as access to water becomes more challenging and as variability in water availability increases, technologies and practices to use less water are seen as a means to manage water-related business risks in the energy sector. An Australian National Water Commission *Waterlines* report found that some coal-fired power stations have reduced their water use per megawatt hour generated by up to 15% (Smart and Aspinall, 2009). The cost of disruption to energy production, such as electricity generation, far outweighs the direct costs to the energy sector for this water. Even without disruption, the marginal product of water consumed in the electricity industry exceeds what is usually paid for it, and is far above that of many competing users (Smart and Aspinall, 2009). Water security risk can encourage greater water conservation in the energy sector, though it is the cost of energy supply disruption rather than the cost of water that provides the conservation incentive.

The onus also lies with governments to set appropriate regulatory and institutional frameworks to provide opportunities for generators and other water users in the energy sector to flexibly manage risks and minimize costs through the efficient pricing of water inputs. Using Australia as an example, these opportunities can (and most likely will) be provided through participation in Australia's water markets. The marginal value of water in electricity generation ranges between $14,000 and $18,000 per megaliter. During the 2002–10 Australian drought, the price of water traded between irrigators peaked at $1200 per megaliter for volumes delivered in a given season. In 2011, however, the market price for water was less than $100 per megaliter. Given these differences, the electricity industry is well placed to compete for the water it needs within existing water markets (DRET, 2011).

For the electricity sector to fully benefit from water markets—and indeed for greater water efficiency to be realized in the energy sector generally—the Australian Government has developed a range of measures that should provide the following for all water users, including electricity generators and gas providers:

- coverage in water access entitlement and water planning frameworks, with power plant use included in the consumptive pool and based on clearly specified water access entitlements that are compliant with the National Water Initiative;
- settled entitlement arrangements for new sources of water (such as groundwater resulting from coal seam gas extraction);
- access to participatory and transparent water planning processes that allow for consideration of supply reliability requirements;
- requirements for the quality of water returned to surface and groundwater systems;
- pricing for supplied water that reflects the full costs of supply and management;
- unrestricted and equitable access to water markets in order to manage the risk associated with water access entitlements and contracts for supply; and
- statutory requirements that demand water availability and reliability be taken into account when planning the location of major developments, including energy generation assets, that require access to water (DRET, 2011).

As is evident, in Australia, the primary drivers to account for interactions between the electricity and water sectors have been the market- and regulatory-based reforms undertaken in the water sector, which in turn have been driven by the significant economic, social, and environmental consequences of the Millennium drought.

5.4 Municipal Water Reuse for Power Plant Cooling

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5.4.1 Introduction

The 2011 drought conditions in Texas and elsewhere highlighted the issue of water supply for power plant use. Competing demands for a dwindling natural resource, long periods of drought, changing precipitation patterns, and increasing environmental and regulatory constraints have electrical generators looking for alternatives to ensure a stable supply of water for cooling and generation requirements. The Department of Energy (DOE) National Energy Test Laboratory has been studying non-traditional water sources for application to power plant uses, and reclaimed water, which is treated sewage effluent discharged from wastewater treatment plants, is increasingly being touted as a reliable alternative to lessen the impact of power plant use on freshwater supply (Veil, 2007).

For more than 40 years, since the mid 1960s, the City of San Antonio has been using reclaimed water for power plant cooling. In fact, the city was one of the early pioneers in the use of reclaimed water for power generation. Following the 10 years of drought from 1947 to 1957, considered the driest period on record for Texas, leaders of City Public Service Board (later named CPS Energy) began to look for ways to conserve Edwards Aquifer water, which until 2002 was the sole source of drinking water for the City of San Antonio and surrounding counties. To meet the increasing energy demand of the growing city and to conserve water from the Edwards Aquifer for potable use, Victor Braunig, then the general manager of CPS Energy, San Antonio's gas and electric utility, envisioned the use of treated effluent discharged from the city's wastewater treatment plants into the San Antonio River as a source for cooling the city's future power plants. Because an adequate amount of storage is needed to stabilize the variability of flow discharged from the wastewater treatment plants and to ensure a consistent supply of water, in the late 1960s Braunig and Calaveras Lakes were built on the southeast side of San Antonio to serve as cooling lakes for CPS Energy's newest generating units. The highly treated effluent is conveyed using the beds and banks of the San Antonio River to diversion pumps located directly downstream of the city's wastewater treatment plants. This indirect use of reclaimed water conserves approximately 40,000 acre-feet of Edwards Aquifer water each year for potable use. Since the initial operations in 1966, approximately 308 billion gallons of Edwards Aquifer water have been saved.

This section provides a description of CPS Energy's experience with use of treated sewage effluent for power plant cooling and a discussion of challenges and emerging regulatory and political issues with use of reclaimed water.

5.4.2 CPS Energy

CPS Energy is San Antonio's gas and electric utility, serving approximately 728,000 electric customers and 328,000 natural gas customers, making it the nation's largest municipally owned gas and electric utility. Its net generating capacity is 6,565 MW, derived from a diverse mix of coal, natural gas, and nuclear; additionally, it has a renewable nameplate capacity of 1,113 MW from long-term purchase power agreements for wind, solar, and landfill gas.

San Antonio is home to 1.3 million people and currently the United States' seventh largest city. It is located in the south central region of Texas, between the Edwards Plateau to the northwest and Gulf Coastal Plains to the southeast. Situated at the western edge of the sub-humid tropical region of Texas, it experiences subtropical climate, with mild to cool winters and long, hot summers. Although the Gulf of Mexico to the south provides a moderating effect and prevents temperatures from rising to extremes, average summer daily maximum temperature is above 90 degrees or higher 80% of the time. Yearly average precipitation is 29 inches; however, there is extreme variability, and can swing from year to year, ranging from 10 inches to 52 inches (NOAA, 2012).

5.4.3 History of Braunig and Calaveras Lake Power Stations

The 10-year period from 1947-57 was the driest one in Texas history. In the San Antonio area, stream flows were reduced to a trickle and, before the end of the drought, major springs in the area (Comal) ceased to flow, something that had never happened in recorded history. The drought reinforced how important and necessary a clean water supply was and just how variable and tenuous that supply was in South Texas.

For almost 35 years, from just after the end of World War II until the early 1970s, CPS Energy experienced a growth rate of 11% per year.

This meant that energy demand, and thus water demand, was doubling every 6.7 years. Over the 20-year period from 1945 to 1965, CPS Energy's annual consumption of aquifer water for electric generation needs increased eightfold from about 1,000 acre-feet per year to about 8,000 acre-feet per year. If continued unabated, the next 20-year period would bring another eightfold increase in aquifer use to 64,000 acre-feet per year (Fulton, 2012).

Accordingly, in 1957 Victor Braunig instructed his staff to find an alternative to the use of pristine Edwards Aquifer water for future power plants. Specifically, he wanted to use wastewater from the city's sewage treatment plants, which presented a problem. The wastewater discharged from the sewage plants had great flow variability—both seasonally and diurnally. While the average flow was more than adequate to meet future cooling water needs, there would be times when the wastewater flow would be insufficient to meet the power plant water demand. This suggested a storage facility would be needed to equalize flow and demand cycles. Additionally, there were biological and chemical uncertainties involved—identifying the best way to store the water and determining how the various components—pumps, condensers, pipes, etc., react when operating on wastewater.

Braunig decided that the best approach would be to use a cooling lake, which would provide the necessary storage as well as some dilution and residence time to minimize the chemical and biological problems that could arise from the use of treated wastewater. In 1960 a large parcel of land was purchased in southeastern Bexar County for a 1,350-acre cooling lake. By 1961 construction began on the project, then known as East Lake. CPS Energy could have built a 10-mile pipeline to transport the treated sewage effluent from the sewage treatment plant but it was decided to obtain a normal state water rights permit and use the river as a means of conveyance. This saved the considerable expense of a pipeline but also allowed for some dilution of the wastewater. (It should be noted, however, that although wastewater constituted more than 50% of the flow of the river under normal hydrological conditions, it would constitute greater than 90% of the river flow during summers and dry periods when most of the water would be pumped; therefore, dilution is negligible during low flow periods.)

The river pump station site was selected downstream from the confluence of the San Antonio River (flowing from the north) and the Medina River joining from the west. This location allowed access to the combined river and treatment plant flows from San Antonio and other smaller communities along the Medina River.

Filling of the lake began in 1963 and immediately a problem was encountered. As soon as the pumps were turned on and water pumped from the river was forcefully expelled from the discharge pipe to fill the reservoir, suds collected into great billowing balls as large as a house and blew across the landscape (Fulton, 2012). In those days householdcleaning products contained lots of phosphates and synthetic detergents that ultimately ended up in the rivers. With air entrained during the pumping process, filling of the lake became an ideal environment for suds production. Fortunately, it was a self-correcting problem because as soon as enough water had been pumped to cover the discharge pipe with about 6 to 8 feet of water, the problem abated. By 1964, the lake was completely filled and rechristened Braunig Lake after CPS Energy's then visionary general manager. The first generating unit, Braunig Unit 1, came on line in 1966, and with its 225 MW capacity, it was the largest and most efficient gas steam unit in CPS Energy's fleet at the time.

In 1968, following the success of the Braunig Lake, a second lake project was begun. This one, Calaveras Lake, would be more than 2.5 times the size of Braunig Lake. Together the two lakes totaled 4,900 acres and contained about 90,000 acre-feet of water. These lakes would accommodate all new electric generating units needed between 1966 and 2010 (with the exception of 200 MW of peaking units installed at Leon Creek). All totaled, more than 4,500 MW of electrical capacity (about 60% of CPS Energy's current total generation portfolio) has been installed at these lakes from 1966 to 2012. This is a considerable amount of generation, especially considering that in 1966, when the first lake unit came on line, the entire electrical capacity of CPS Energy was only 780 MW.

In 1987, with the construction of the city's 125 MGD Dos Rios Wastewater Plant, CPS Energy secured the water supply to the lakes by contracting with the Alamo Conservation and Reuse District (predecessor to San Antonio Water Systems' (SAWS), CPS Energy's sister utility) to provide 40,000 acre-feet of treated sewage effluent per year with two options to add increments of 5,000 acre-feet/yr each. In fact, proceeds from this contract were used as seed money to establish the now very successful SAWS 35,000 acre-feet/year direct recycled water delivery system. Although the average surface water withdrawal in the last 12 years (2001-2012) was 30,000 acre-ft/year, this contract was amended in 2011 to 50,000 acre-feet/year to ensure that there is enough water under contract to supply future plant expansion and to meet water needs during a period of prolonged drought. This proved useful during the drought in 2011, with Calaveras requiring more than 43,000 acre-ft to meet the high rate of natural evaporation and the plants' cooling demands (natural evaporation for 2011 was almost 50% of diversion).

Today, after more than 40 years, Braunig and Calaveras Lakes not only help the utility meet 60% of San Antonio's electrical needs, they also provide a valuable recreational resource for residents of Bexar County and surrounding areas. Both lakes are stocked with a variety of fish and are very popular with sport fishermen. In addition to water-based recreation, Braunig and Calaveras Lakes offer productive aquatic habitats, wetlands, and nesting areas for migratory and wading birds, and a diverse natural environment for wildlife that inhabit the surrounding undeveloped area.

5.4.4 Braunig and Calaveras Power Stations

CPS Energy owns and operates both the Braunig and Calaveras power stations, which are located on the southeast side of Bexar County downstream of four SAWS wastewater plants (Figure 5-1). The stations provide approximately 60% of CPS Energy's generation portfolio (Table 5-1). The circulating cooling system at both Braunig and Calaveras power stations use the cooling lakes as a heat sink. On an annual average basis, about half the evaporation from the lake is natural evaporation of the surface water; the remainder is forced evaporation, which is the result of discharging warm condenser cooling water from the units. Cooling water is withdrawn from the lake, passed through the condensers, and then returned to the lake for recirculation (technically, the use of the reservoirs makes this system closed-loop cooling since the water is eventually returned back to the lake). Lake makeup water is pumped from the San Antonio River as needed.

Table 5-1. **Generation Capacity at Braunig and Calaveras Lakes.**

Lake	Plant Units	Type	Net Generating Capacity
Braunig	Braunig 1, 2, &3	Gas/Oil	867
	Arthur von Rosenberg	Combined Gas Cycle	490
	VHB Peakers CT-5, 6, 7, &8	Simple Cycle Combustion Turbines (Gas/Oil)	184
Calaveras	OW Sommers 1 & 2	Gas/Oil	830
	JT Deely 1 & 2	Coal	840
	JK Spruce 1 & 2	Coal	1,350

Both lakes are off-channel reservoirs; Braunig Lake was constructed by impounding Arroyo Seco, and Calaveras Lake by impounding Calaveras and Chupaderas Creeks, all minor tributaries of the San Antonio River. These are wet weather creeks and because of insufficient inflow from the watershed to maintain lake levels, makeup water is primarily comprised of highly treated wastewater discharged from San Antonio's wastewater treatment plants delivered through the beds and banks of the San Antonio River. Withdrawal from the San Antonio River is permitted under two surface water rights, and the supply is secured by a 50,000 acre-ft/year recycled water contract with the San Antonio Water System. The river water, including the highly treated effluent is pumped from the banks of the San Antonio River 4.3 miles uphill to Calaveras, and 0.25 miles uphill to Braunig Lake.

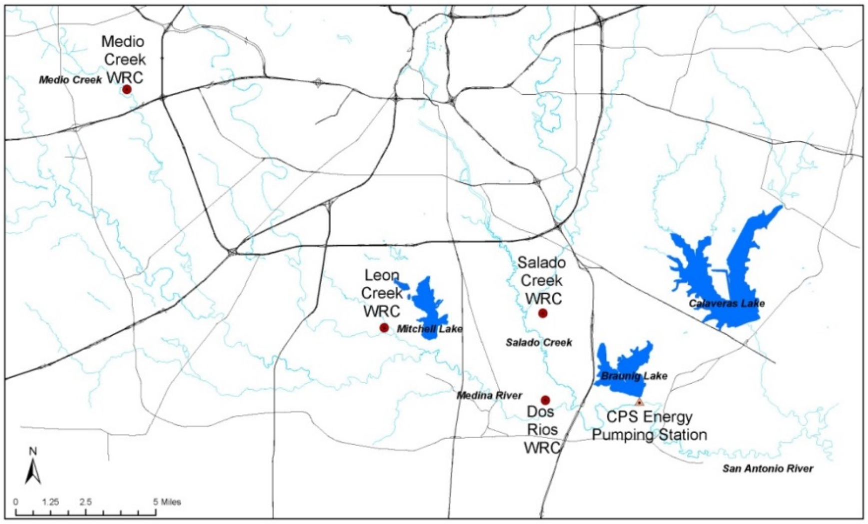

Figure 5-1. Location of San Antonio Wastewater Treatment Plants and CPS Energy Braunig and Calaveras Lakes.

Braunig Lake is a 1,350 acre-feet cooling reservoir, with an average depth of 18 feet and a maximum depth of 45 ft. The lake is operated at a constant level (varies 1 to 2 ft annually), with an operating level of 507 ft MSL. Cooling water is withdrawn from the rear of a half-mile-long intake canal located in the northeast arm of the lake, passed through the condenser tubes in a single pass, discharged into a canal located in the southwest arm of the lake, and then recirculated back into the reservoir (Figure 5-2). The average residence time from the point of discharge to the intake is approximately three days (Fulton, J. E., personal communication, August 24, 2012).

Figure 5-2. Braunig Lake Power Station. Intake at the northeast arm of the lake and discharge at the southern and western areas of the lake.

Calaveras Lake is a 3,450 acre lake, with an average depth of 18 ft and a maximum depth of 45 ft. Operating lake level is maintained between 484 and 485 ft MSL. Cooling water is withdrawn at the rear of a 1.8-mile intake canal. An inverted weir located at the entrance of the canal allows water to be drawn from the main and deeper part of the reservoir below 26 feet deep. The cooling water is discharged into two discharge canals—the Sommers and Deely plants discharge at the northwestern arm of the lake and the Spruce plants discharge on the northeastern region of the lake (Figure 5-3). Average residence time for recirculation is approximately eight days from the discharge points (Fulton, J.E, personal communication, August 24, 2012).

Figure 5-3. Calaveras Lake Power Station. The cooling water intake is from the rear of the 1.8-mile-long intake canal. Spruce plants discharge at the northeastern arm of the lake and Sommers/Deely plants discharge at the northwestern arm of the lake.

5.4.5 Water Chemistry

The Braunig and Calaveras Lakes are used as heat sinks for the cooling water to help condense steam into water in the Rankine steam cycle. Cooling is achieved by passing water through the condensers in a single pass and discharging it back into the water body a few degrees warmer. At Calaveras, the discharge of the condenser is usually 10^{o}F to 15^{o}F higher than the intake temperature.

Due to the nutrient-rich source water and the high nutrient loading from the large population of water fowls the lake supports, algae is a consistent problem for operations at both reservoirs. High phytoplankton productivity and the high mineral content of the Edwards Aquifer water, which is the ultimate source of the treated effluent, keep the pH value of the lakes above 9. In order to prevent scaling and biological growth in the condenser tubes, which would reduce heat transfer efficiency or even block the tubes, the cooling water is treated continuously with a scale-inhibiting chemical and, for up to two hours per day, with an anti-biological treatment.

For many years after the lakes were built, no anti-scalant chemicals were used and chlorine gas was used until the mid-1990s to control biological growth. But for the past 15 years, CPS Energy has been using a chemical scale inhibitor that is a combination of phosphobutane tricarboxylic acid (PBTC), polymaleic acid (PMA), and polyacrylic acid (PAA). This is fed at varying rates depending on the lake conditions. The anti-biological chemicals used are a combination of sodium hypochlorite and sodium bromide. The sodium bromide is necessary due to the limited effectiveness of sodium hypochlorite at the lake pH range of 8.6 to 9.2. The objective of the treatments is to prevent scaling and biological growth during the 8 to 10 seconds that the water passes through the condenser tubes. Without treatment, the tubes would rapidly foul and limit flow. The loss of heat transfer would rapidly reduce unit efficiency and require unit shutdown as the temperature increased.

Discharge of the condenser cooling water into the lakes is monitored under a State of Texas wastewater discharge permit, the Texas Pollutant Discharge Elimination System (TPDES). The State of Texas, through the Texas Commission on Environmental Quality (TCEQ), is delegated by the U.S. Environmental Protection Agency (USEPA) to administer the National Pollutant Discharge Elimination System (NPDES) permits. Cooling water and other low-volume wastewater discharged into the lakes are closely monitored to ensure that the categorical standards for steam electric power generation (40 CFR Part 423) are met. To prevent acute toxicity to aquatic species, the USEPA established the limit for Total Residual Chlorine under Part 423 to a daily maximum of 0.2 mg/L; chlorination is limited to two hours per day. Although the State of Texas has not established numerical temperature criteria for industrial cooling lake impoundments,[30] the Calaveras plant has site-specific TPDES thermal limits; the Braunig plant does not.

Even with the additional heat load of the new 785 MW JK Spruce 2 in 2010, the cooling water discharge temperatures at Calaveras Lake never reached maximum permit levels during the abnormally hot, dry summer of 2011. Because the lake is normally operated at a constant level and because the circulating intake water is drawn from the deeper,

[30] See 30 Texas Administrative Code (TAC) §307.4, Texas Surface Water Quality Standards, 2010. Retrieved on February 4, 2013, at http://info.sos.state.tx.us/pls/pub/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=30&pt=1&ch=307&rl=4

cooler part of the lake, overall discharge temperature remained at the designed range of temperature discharge points. However, the additional heat load and increased natural evaporation at Calaveras Lake raised the reservoir makeup water requirement by roughly 30% during the 2011 Texas drought, although overall diversion was still well below CPS Energy's surface water rights and reuse water contract.

5.4.6 Challenges of Reclaimed Water Use

CPS Energy has successfully employed the indirect use of wastewater for power plant cooling for more than 40 years; however, it is not without several challenges and problems. Power plants considering indirect use of treated effluent should be prepared to address technical, regulatory, and political constraints. Challenges include reservoir water quality, effluent and thermal discharge limits, new environmental regulations, and competing interests for reclaimed water.

While the municipal effluent is treated to secondary treatment standards and disinfection before discharge to the San Antonio River, CPS Energy provides no additional treatment of the wastewater delivered to the lakes. The high nutrient content of the source water has produced algal blooms in the reservoirs, creating oxygen depletion in some areas of the lakes that could result in fish kills. This is less an issue for Calaveras Lake because the use of the inverted weir, which draws water from the deeper region of the lake, allows for a much better circulation of the water in the reservoir and prevents oxygen stratification. Ironically, it is the high nutrient water that makes Calaveras and Braunig Lakes very productive reservoirs and popular with sports fishermen. The high nutrient content of the makeup water sustains high plankton densities in the lakes, which in turn supports high densities of forage fish. Studies conducted at Braunig and Calaveras Lakes indicate the standing crop of fish per acre produced in the reservoirs is in excess of 1,500 pounds per acre, with forage species accounting for the majority of fish by number and weight (PBS&J, 2009a; PBS&J, 2009b).

Both forced evaporation and the high rate of natural evaporation produce a "kettle boil" effect in the reservoirs, which concentrates lake water constituents. Although regular monitoring of lake water and sediments indicates insignificant concentrations of trace metals and other pollutants, the trend for total dissolved solids (TDS) is increasing (PBS&J, 2010). This trend is exacerbated by the voluntary practice of not allowing blowdown from the reservoirs to the San Antonio River to conserve water. Water is released from the reservoirs only during times of high precipitation, which is not a common event in the South Central Texas area. Additional chloride loading from the flue gas desulfurization system at Calaveras Spruce plant may also be contributing to the increasing TDS trend at Calaveras Lake. CPS Energy is currently evaluating its blowdown practice and potential technical solutions to the TDS issue at both reservoirs.

Additionally, regulatory constraints and political pressures on surface water withdrawal of reclaimed water are emerging. The U.S. EPA has recently proposed additional regulations to implement Phase II of Section 316(b) of the Clean Water Act (CWA), which requires water cooling intake structures to reflect the best technology available for minimizing adverse effects on aquatic ecosystems. Because of the potential for adverse effects on aquatic species and because of stricter requirements for intake structures, it is unlikely that new steam units with once-through cooling will be built in the future. Although both Braunig and Calaveras Lakes are man-made, closed-cooling recirculating lakes filled with treated wastewater, and are managed fisheries with continuous stocking of game and non-game fish, the lakes are considered waters of the U.S. by the EPA and therefore subject to the proposed Phase II 316(b) rules should they go into effect.[9]. These regulations will not only require costly retrofits for existing units, but also discourage use of once-through cooling for new units to be built on the lakes. Additionally, given the 40-year growth in generation capacity, the lakes, Calaveras in particular, may be closely approaching their design capacity in terms of thermal loading, thus restricting additional thermal steam units built on the lakes.

As with any water supply, competing demands for wastewater is increasing, and this increased competition puts pressures on the indirect reuse of wastewater. The indirect reuse of wastewater involves the discharge of municipal effluent from a wastewater treatment plant into a river or stream and then diverting it downstream for beneficial use. Since wastewater discharged into a river becomes state water in Texas, proposed environmental flow regulations will impact new surface water rights and beds and banks permits needed for the conveyance of the treated effluent in the state’s watercourse. In Texas, all surface water is state water, and a generator that desires to use effluent discharged to a watercourse must first obtain surface water rights and a beds and banks permit from the Texas Commission on Environmental Quality (TCEQ). If authorized by TCEQ, this diversion will be subject not only to carriage losses, but also to existing water right holders and to reservation for in-stream uses such as beneficial inflow to protect the bays and estuaries.

5.4.7 Water Supply Management Strategies

In view of the above constraints, CPS Energy and other power utilities are employing a variety of strategies to manage fleet-wide water requirements and their supply resources. These strategies include:

- Implementation of water efficiencies in plant operations to keep surface withdrawal and water consumption relatively low. For example, the majority of the plants' low-volume waste streams are used in other processes, treated, then discharged back into the lakes (under a TPDES permit), and recirculated as part of the condenser water.
- Cooperation with stakeholders to lessen impact of water diversion on downstream users.
- Shift to low water-intensive generating technology.
- Diversification of generation resources to include renewables, such as landfill gas, solar, and wind that do not require water use.
- Implementation of demand reduction programs to reduce electric consumption.

Water efficiencies and conservation achieved in plant operations have kept CPS Energy average annual withdrawal at 30,000 acre-ft and average annual combined forced evaporation at 17,000 acre-ft for Braunig and Calaveras plants in the last 12 years (2001-2012). This is well below the water rights and reuse contract, thus leaving several thousands of acre-feet of water available for river flow. In addition, CPS Energy works closely with SAWS, the San Antonio River Authority (SARA), the South Texas Watermaster, and downstream water users to time river pumping operations to lessen the impact of water diversion. It has informal agreements with SAWS and SARA to keep flow at the Falls City gage, located downstream of CPS Energy's diversion point, a minimum of 55,000 acre-ft/year. CPS Energy is deactivating older generation units and diversifying its generation capacity to include low water intensive technologies such as combined cycle gas units, simple cycle gas turbine units, landfill gas, solar, and wind. In fact, 12.8% of CPS Energy's generating capacity is now derived from renewable resources, with 1,059 MW of purchased power derived from wind-generated electricity (currently, the largest in municipally owned utilities), 44 MW of solar, and by 2017, an additional 400 MW of solar with the recent OCI solar power agreement. This shift to renewable electricity has saved an estimated 20,300 acre-ft of water from 2002 to 2011. Recognizing that energy saved is water saved, CPS Energy is also implementing a demand management reduction and conservation program for its customers through the Save for Tomorrow Energy Plan (STEP), with a goal of approximately 771 MW reductions by year 2020. So far, 567 acre-ft of water savings has been achieved from 2005 to 2011.

5.4.8 Conclusions

The use of reclaimed water for power generation is a reliable alternative to freshwater supply for power plant cooling. For more than 40 years, the City of San Antonio has successfully utilized treated wastewater effluent for power plant cooling. With the use of cooling reservoirs for storing and circulating reclaimed water diverted from the San Antonio River, water from the Edwards Aquifer is conserved for high-quality use.

Although the water quality level of treated effluent has greatly improved in the last 30 years, primarily due to the implementation of the Federal Clean Water Act, there are technical and water quality issues associated with the use of reclaimed water. High nutrient content, algal blooms, and increased TDS concentration pose reservoir water quality issues that must be addressed to meet regulatory limits and to support a sustainable ecosystem. New regulatory requirements and political issues associated with competing demands for reclaimed water are also emerging and must be addressed as part of the decision to use treated wastewater.

5.4.9 Acknowledgements

The authors wish to thank Joseph E. Fulton, retired Director of Environmental and Generation Planning of CPS Energy, who offered access to his unpublished manuscript and provided details and substantial contribution on the history of CPS Energy. Also our thanks to CPS Energy staff Melanie Green, John Kosub, and Doris Cooksey for their time and effort reviewing this paper. Their insight and institutional knowledge of CPS Energy provided an invaluable resource. We also want to acknowledge Clayton Hahn, also of CPS Energy, for providing the graphics and images used in this paper.

5.5 Case Study of Dry Cooling in South Africa

Johannes Pretorius, Francois du Preez
Eskom

5.5.1 Introduction

South Africa is a semi-arid country with an annual rainfall (~460–500 mm/yr), which is approximately half of the global average (~715–990 mm/yr). South Africa can be demarcated into 19 water management areas. Most of these catchments have a supply-demand balance or are in deficit. A number of management strategies are being implemented to "stretch" the water resources, such as demand management and reuse.

South Africa's state-owned utility, Eskom, is the main electricity generating institution in Southern Africa. Power Generation (and by implication Eskom) is recognized by South Africa's National Water Act (NWA) as a strategic water user and is granted water use at a 99.5% level of assurance. Notably, Eskom uses approximately 1.5% to 2% of the total amount of water consumed in the country, mainly by its fleet of wet-cooled, coal-fired power stations.

Eskom has implemented a dry-cooling policy since the 1980s that recognizes the water scarcity in South Africa and Eskom's responsibility in this regard as a major water user. South Africa's Department of Water Affairs (DWA) has also drafted legislation in terms of the NWA, which specifies the use of dry cooling as the default cooling technology for future power plants—these regulations were under review as of late 2012. A comprehensive water use license application to DWA is required for any new power station, and DWA decides whether or not to grant such a license. In this way, environmental role players within the government control the allowable water usage allocated for new power plants.

Eskom historically utilized wet-cooled power stations due to their high thermal efficiency and the need to use proven (mature) technologies. As cooling tower evaporation accounts for approximately 80% of total plant water usage, such wet systems require significant water quantities for operation. In light of the regulations discussed above, Eskom implemented dry-cooling systems at many of its power stations. The only driver behind this decision was water scarcity, especially in the regions where South Africa’s coalfields and coal-fired power plants are concentrated.

Eskom operates some of the largest dry-cooled power stations in the world. Within the Eskom fleet of 13 currently operating coal-fired power stations, four employ dry-cooling technology, while another two large dry-cooled, coal-fired power stations were =under construction as of 2012. Table 5-2 shows the various dry-cooled Eskom power station units.

Table 5-2. Dry-cooled power station units in the Eskom fleet.

Year commissioned	Power station name	Unit size [MW]	Cooling technology
1971, 1977	Grootvlei Unit 5-6	2 x 200	Indirect dry-cooled
1987	Matimba Unit 1-6	6 x 665	Direct dry-cooled
1988-1993	Kendal Unit 1-6	6 x 686	Indirect dry-cooled
1996-1998	Majuba Unit 1-3	3 x 657	Direct dry-cooled
Under construction	Medupi Unit 1-6	6 x 794	Direct dry-cooled
Under construction	Kusile Unit 1-6	6 x 798	Direct dry-cooled

5.5.2 History and Plant Configurations

In 1966 Eskom decided to extend Grootvlei power station, and the strategy was both to add generation capacity without increasing water consumption and to gain dry-cooling experience. Units 5 and 6 were subsequently added to the power station, where Unit 5 employs an indirect system with a spray condenser and natural draft dry-cooling tower, while Unit 6 uses an indirect system with a surface condenser and natural draft dry-cooling tower. At the time these two units were the largest dry-cooled units in the world (see Figure 5-4).

Eskom constructed additional dry-cooled, coal-fired power stations in the 1980s. The first, Matimba, consists of a so-called six-pack configuration— six units next to each other, all dry-cooled using air-cooled condensers (ACCs) (see Figure 5-5). (The six-pack configuration is typical of Eskom’s power station fleet, whether wet- or dry-cooled). At the time of construction, the Matimba ACC was 11 times larger than the largest ACC built elsewhere in the world.

The next dry-cooled power station constructed by Eskom, Kendal, employed an indirect dry-cooling system. Each unit's cooling system consists of a surface condenser and natural draft dry-cooling tower. A six-pack configuration was again used with three cooling towers on either side of the power block (see Figure 5-6).

Figure 5-4. Natural draft dry-cooling towers for Grootvlei PS Unit 5 & 6.


Figure 5-5. Matimba power station with its ACC.


Figure 5-6. Kendal power station with its indirect dry-cooling system.

Construction then started on Majuba power station in 1996. It was decided to build the power station with three dry-cooled (ACC) units and three wet-cooled units. Originally, all six units were supposed to be dry-cooled; however, a large dam was constructed in the area, which made sufficient water available for use by the wet-cooling systems of Units 4 to 6. Figure 5-7 shows Majuba power station with its ACC on Units 1 to 3.

Figure 5-7. Majuba power station with its ACC on Units 1 to 3.

Two large coal-fired power stations, Medupi and Kusile, are currently under construction. Both of these stations employ a six-pack configuration with ACCs as the main cooling system. Figure 5-8 and Figure 5-9, respectively, show construction photos for these stations.

Figure 5-8. Medupi power station with its ACC, currently under construction.

Figure 5-9. Kusile power station with its ACC, currently under construction.

5.5.3 General Operational Experience With Dry-Cooling Systems

Eskom's use of dry-cooling systems has undoubtedly succeeded in achieving its main objective: the conservation of water. Typically, a 4,800 MW dry-cooled power station consumes approximately 3.5 to 6 million m^3 water per annum, compared to 45 to 50 million m^3 water for a wet-cooled power station of similar capacity. In general, however, dry-cooling systems are less efficient than wet-cooling systems and more sensitive to ambient conditions. Also, their capital and operating costs are higher compared to those of wet systems.

In particular, ACCs can be sensitive to high wind conditions from certain directions (from the back of the boilers toward the ACC). When such wind conditions are combined with high ambient temperatures, the power station units may experience significant reductions in power output due to thermodynamic inefficiency (high turbine backpressure) resulting from decreased cooling system performance. These occurrences have prompted Eskom to implement a number of improvements in the design for its latest power stations with ACCs—Medupi and Kusile—including moving the ACC away from the turbine hall. In terms of indirect dry-cooling, the experience from Kendal has shown this system to be less sensitive to windy conditions.

In general, due to the larger number of moving parts for ACCs compared to natural draft indirect dry-cooling systems, ACCs have more maintenance requirements, while the capital cost of indirect systems are typically somewhat higher than for ACCs. In Eskom's experience, both direct and indirect dry-cooling systems can provide a good solution for power plant cooling in areas where water scarcity is a significant factor.

5.6 Power Plant Cooling Systems in Spain

Mónica Copete Montiel
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5.6.1 Introduction

A site evaluation for a power plant involves criteria such as health and safety, environmental and social impacts, engineering needs, and economics. These criteria encompass different aspects such as geology, seismology, weather conditions, flooding, and population. The selection of a cooling system depends on various parameters: process and operating requirements, legal constraints, gross electrical output, surface water and groundwater availability for water cooling system components, environmental and aesthetic concerns, social factors, water consumption and withdrawal, and others.

This case study describes some aspects of the Spanish climate and relationship to nuclear power plants and their cooling technologies and water sources.

5.6.2 Iberian Climate Atlas

During recent years, the occurrence of extreme phenomena and the change in observed average conditions provide evidence of increased climate variability and climate change. In Spain as well as throughout the globe, climate factors such as air temperature and precipitation have a significant impact on socioeconomic development and human well-being. The characterization of climate in Spain shows a country with several types of climate (see Figure 5-10).

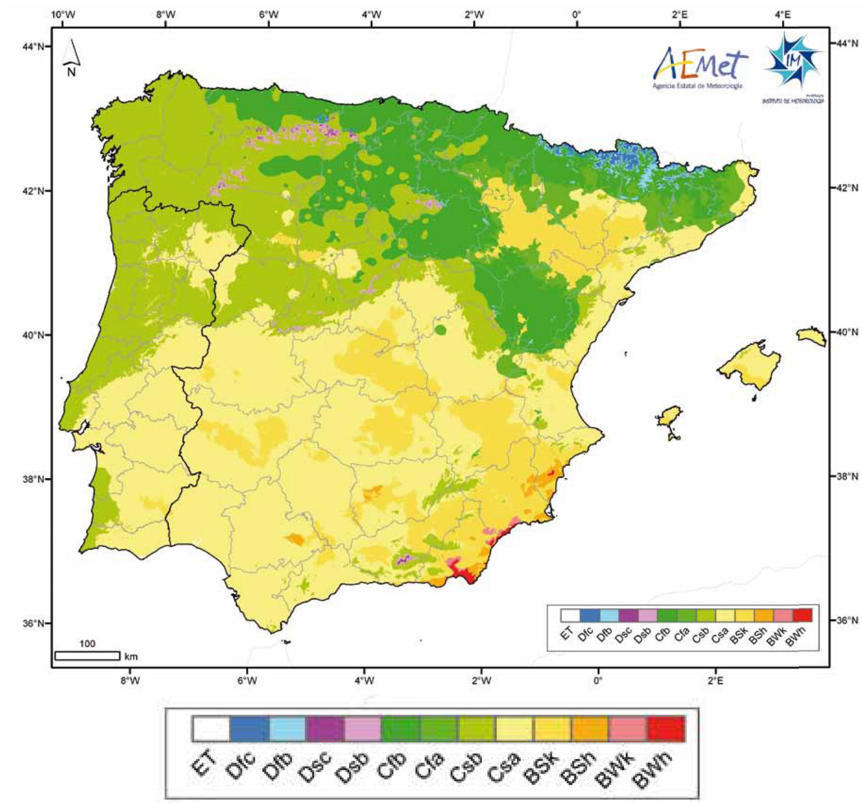

Figure 5-10. Köppen-Geiger Climate Classification for the Iberian Peninsula (Spain and Portugal) and the Balearic Islands. Agencia Estatal de Meteorología (http://www.aemet.es/).

5.6.2.1 Dry Climates—Type B

BWh (hot desert—above 18ºC) and BWk (cold desert—below 18ºC)

There are small areas in the southeast of Spain coinciding with minimum rainfall values for the Peninsula.

BSh (hot steppe—above 18ºC) and BSk (cold steppe—below 18ºC)

In Spain, this is widespread in the southeast of the Peninsula and the Ebro Valley in the northeast.

5.6.2.2 Temperate Climates—Type C

The average temperature in the coldest months in Type C climates is between 0°C and 18°C.

Csa (temperate with dry or hot summer)
This is the type of climate that covers most of Spain, approximately 40% of its surface: the southern central plateau region and the Mediterranean coastal regions, with the exception of the arid zones in the southeast.

Csb (temperate with dry or temperate summer)
This covers the majority of the northeast of the Peninsula and numerous mountainous regions.

Cfa (temperate with a dry season and hot summer)
This is mainly seen in the northeast of the Peninsula, within an area of medium altitude, which surrounds the Pyrenees and the Iberian mountains.

Cfb (temperate with a dry season and temperate summer)
These areas are located in the mountainous regions of the north of Spain, the northern central plateau region and a large part of the Pyrenees, with the exception of areas of high altitude.

5.6.2.3 Cold Climates—Type D

The average temperature for the coldest month is lower than 0°C, and the average temperature of the hottest month is higher than 10°C**.**

Dsb (cold with temperate and dry summer) and Dsc (cold with dry and fresh summer)
These are located in small areas of the mountainous regions at higher altitudes.

Dfb (cold without dry season and temperate summer) and Dfc (cold with a dry season and fresh summer)
These areas are located in higher altitudes in the Pyrenees and in some small areas at high altitude in the northern Mountain Ranges.

5.6.2.4 Polar Climates—Type E

ET (tundra*: *the average temperature for the hottest month is higher than 0°C)

This is seen only in small areas on the highest elevations of the Central Pyrenees.

5.6.3 Spanish Power Plants

Figure 5-11 and Figure 5-12 show the location of all Spanish Power plants and specifically the nuclear power plants, respectively. Looking at the location of the power plants and the climate of Spain in the previous section, one can see there might be difficulty in using water for cooling in the southern half of the country.

●	Coal Power	■	Hydro-electric Power > 100 MW
◆	Nuclear Power		Wind Power
⬟	Fuel and Gas Power		Solar Photovoltaic Power
▼	Combined Cycle Power		Solar Thermal Power

Figure 5-11. Map of power plants in Spain. Red Eléctrica de España (www.ree.es).

As mentioned in Section 2.1, in selecting a power plant cooling system, key indicators that relate to water security are water consumption and availability. As shown in Figure 1-5, nuclear power plants tend to have the highest quantities of operational water consumption. This case study includes information on the Spanish nuclear power plants' cooling systems. Table 5-3 shows the main characteristics of the eight nuclear power plants (NPPs) operating presently in Spain.

Table 5-3. Characteristics of Spanish nuclear power plants (Source: Consejo de Seguridad Nuclear, www.csn.es).

Operating Year	Power station name	Location	Design*	Unit size [MWe]	Cooling technology
1970	Sta. María de Garoña	Burgos	BWR	466	Ebro River
1980	Almaraz I	Caceres	PWR	1049	Arrocampo Reservoir
1983	Almaraz II	Caceres	PWR	1045	Arrocampo Reservoir
1982	Ascó I	Tarragona	PWR	1033	Once-through (Wet-cooling towers + Ebro River)
1985	Ascó II	Tarragona	PWR	1027	Once-through (Wet-cooling towers + Ebro River)
1984	Cofrentes	Valencia	BWR	109	Closed-cycle (Wet-cooling towers)
1987	Vandellós II	Tarragona	PWR	1087,1	Once-through (Mediterranea n Sea)
1987	Trillo	Guadalajara	PWR	1066	Closed-cycle (Wet-cooling towers)

* PWR = pressurized water reactor, BWR = boiling water reactor

5.6.4 *Cooling Tendency*

As indicated in Table 5-3, the conventional process of cooling of the most Spanish nuclear power plants is based on open-cycle (once-through) cooling systems in which circulating water is drawn from a sea, lake, or river, flows through tubes of a steam surface condenser, and is returned slightly warmer to the source. The use of lake and river water has been especially important in Spain for the last years because key indicators of the reduction of annual average rainfall as well as its distribution throughout the country.

Figure 5-12. Map of nuclear power plants in Spain (Source: www.csn.es).

Every river watershed authority manages the existing water sources in each hydrological demarcation in Spain providing concessional water flow rates to consumers according to current legal frameworks. Also, these laws set those priorities and compatibilities among river water consumers in times of water scarcity. The major water consumers of river water are the following:

- municipal water supply
- irrigation and agricultural uses
- industrial uses to generate energy power
- other industrial uses
- aquiculture
- recreational uses

Table 5-4 lists water concessions to the Spanish nuclear power plants. These quantities are for withdrawal, and practically most of each water quantity listed in Table 5-4 goes back to the corresponding river or reservoir. The quantity and percentage of concession returned to the source vary between a closed-cycle cooled by wet-cooling towers (e.g., Trillo NPP) and one cooled by a reservoir (e.g., Almaraz I & II NPPs). For instance, the return flow rates for these NPPs are 46% and 90%, respectively.

Table 5-4. Water concessions, for withdrawals, for the Spanish Nuclear Power Plants (Sources: www.chebro.es/www.chtajo.es/ http://www.chj.es/www.magrama.gob.es/www.cncofrentes.es)

NPP	Water Source	Concession (hm^3/year)	River Watershed Authority
Sta. María de Garoña	Ebro River	768	Confederación Hidrográfica del Ebro
Almaraz I & Almaraz II	Arrocampo Reservoir	437	Confederación Hidrográfica del Tajo
Ascó I & Ascó II	Ebro River	2,280	Confederación Hidrográfica del Ebro
Cofrentes	Cortes Reservoir	33.7	Confederación Hidrográfica del Júcar
Trillo	Tagus River	37.8	Confederación Hidrográfica del Tajo

For the last years, water availability restrictions and rigorous environmental laws are being imposed on water use as a consequence of extreme climatic conditions. This situation has led to the development of extensive feasibility studies about cooling alternatives to the conventional cooling system. These studies have yielded the following:

- Natural and mechanical draft wet- (evaporative) cooling towers are commonly used as cooling options to once-through cooling (see Chapter 3).

Currently, some Spanish nuclear power plants use wet-cooling towers (natural or mechanical draft) as a supplement once-through cooling system. Although, studies developed show a trend toward this type of cooling as a closed-through cooling system (as at Cofrentes and Trillo NPPs).

- Natural or mechanical draft dry-cooling towers uses air instead of water in order to evacuate heat to the atmosphere (see Chapter 3 for engineering, Chapter 4 for economics).

The dry-cooling technology is considered for those nuclear power plants located in places where there is insufficient availability of water (for instance, in the south of Spain). The main disadvantages of this type of cooling tower are that dry-cooling requires huge areas to be erected and the size of the structure creates a visual impact. Both these inconveniences have a relevant impact in Spain because of its topography and population distribution.

Due to this, other cooling system alternatives are contemplated, such as single circuits formed by:

- Serial natural dry- and mechanical wet-cooling towers
- Serial mechanical dry- and wet-cooling towers

Once the type of cooling system has been selected, an optimization is usually required. The degree of optimization is a function of several parameters from many different performance criteria such as:

- Economic Criteria (see Chapter 4)
- Engineering Criteria (see Chapter 3)
- Environmental Criteria (see Chapter 2)
- Sociological Criteria

In spite of studies and analyses performed to improve the existing cooling systems of Spanish nuclear power plants, the impact of the current global economic situation on the Spain´s growth has forced the postponement of most of the high-cost investment plans considered in the past years…for now.

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Glossary

air-cooled condenser	A type of power plant condenser that flows air, typically blown by fans, over condenser tubes to absorb the heat from the steam turbine exhaust steam.
bleed	Same as blowdown water.
blowdown water	Water discharged from wet-cooling towers in order to remove total dissolved solids (TDS) in the cooling water that must stay below design specification. The TDS of the cooling water increases during operation due to evaporation of cooling water while the solids are left in the cooling system.
condense	To undergo the act of condensation
condensation	The conversion of a substance (as water) from the vapor state to a denser liquid or solid state, usually initiated by a reduction in temperature of the vapor
condenser	A device that condenses exhaust steam from steam turbines in a thermal power plant. Power plant condensers typically use flowing cooling water to absorb the heat from the steam.
consumption (or consumptive use)	That part of water withdrawn that is evaporated, transpired, or incorporated into products or crops such that it is not returned (discharged). For power plants, consumption includes on-site consumption such as for dust control and flue gas desulfurization. See USGS Water Use Survey, EIA form 923, and Chapter 1 for diagrams and further discussion.
cooling tower	Structure used to dissipate heat from condenser cooling water to the environment.
dry cooling	A term used to describe cooling systems for thermoelectric (steam-electric) power plants that do not use water, but instead use air. Same as "air-

cooled."

direct dry cooling	The design of an air-cooling system for a thermal power plant in which steam from the steam cycle is ducted directly to an air-cooled condenser
discharge (or discharged flow)	The water returned to a water body, not necessarily the same water body as in the withdrawal. By definition, discharge is less than or equal to withdrawal. The specific point of discharge is not necessarily the same as the point of withdrawal. See USGS Water Use Survey, EIA form 923, and Chapter 1 for diagrams and further discussion.
diversion (or diverted flow)	The water moved from a watercourse without immediate beneficial use, for purposes such as filling a cooling pond or adding water to a lake from which thermoelectric power water withdrawals can occur. See EIA form 923 and Chapter 1 for diagrams and further discussion.
drift	Water that flows out of a wet-cooling tower as liquid water flowing with the forced or induced airflow. This water does not absorb an appreciable amount of heat from the power plant and is generally seen as a water loss.
entrainment	Process by which organisms are drawn into a facility. Once inside the facility, organisms are exposed to high pressures and temperatures which result in death
eutrophication	A reduction in the amount of oxygen dissolved in water. The symptoms of eutrophication include blooms of algae (both toxic and non-toxic), declines in the health of fish and shellfish, loss of seagrass beds and coral reefs, and ecological changes in food webs
forced draft (cooling tower)	A mechanical draft cooling tower that creates an upward flow of air through the cooling tower by placing fans at the intake of the cooling tower. This creates relatively high intake air velocities and low

exiting velocities.

forced evaporation Evaporation from surface water bodies that is *additional* to natural evaporation, due to the surface water being at an elevated temperature that results from hot water discharge from power plant condensing systems that are part of once-through or recirculating cooling designs

heat rate A measure of power plant efficiency that is the energy content of the fuel needed per unit of net electricity output (e.g., Btu/kWh, J/kWh).

impingement Process by which fish and other organisms are trapped against screens when water is drawn into a facility's cooling system. Young and small fish are the most susceptible and injuries often prove fatal

indirect dry cooling The design of an air-cooling system for a thermal power plant in which steam from the steam cycle is condensed in a conventional, water-cooled surface condenser and the heated cooling water is cooled in an air-cooled heat exchanger

induced draft (cooling tower) A mechanical draft cooling tower that creates an upward flow of air through the cooling tower by placing fans at the discharge of the cooling tower. This creates relatively low intake air velocities and high exiting velocities.

makeup water The water that needs to be added to wet-cooling tower systems in order to keep the cooling water flow rate constant and "makeup" for water that is lost due to evaporation, blowdown, and drift.

morbidity Rate of incidence of disease for living organisms

mortality The number of deaths in a population, or the death rate of living organisms

natural draft (cooling tower) A cooling tower that creates an upward flow of air through it by utilizing the natural buoyancy of warm and moist air within the cooling tower relative to the cooler and drier air outside it.

natural evaporation Evaporation from surface water bodies that occurs due to the natural ambient conditions (temperature, humidity, wind speed, etc.) of the local climate

non-contact cooling water Water used for cooling which does not come into direct contact with any raw material, product, by-product, or waste

nonpoint source (water pollution) Nonpoint source pollution generally results from land runoff, precipitation, atmospheric deposition, drainage, seepage, or hydrologic modification. In the United States, the term "nonpoint source" is defined to mean any source of water pollution that does not meet the legal definition of "point source" in Eection 502(14) of the Clean Water Act.

once-through A design for thermal power plant cooling where water is withdrawn, run through a surface condenser to absorb heat from the steam cycle, and then discharged back into the environment. The water withdrawal is equal to, or nearly equal to, the discharge rate, and most water consumption related to cooling is due to forced evaporation. See EIA form 923 and Chapter 1.

parallel condensing system Cooling technology that combines an air-cooled steam condenser in parallel with a surface condenser coupled to a cooling tower

point source (water pollution) This term means any discernible, confined, and discrete conveyance—including but not limited to any pipe, ditch, channel, tunnel, conduit, well, discrete fissure, container, rolling stock, concentrated animal feeding operation, or vessel or other floating craft—from which pollutants are or may be discharged. This term does not include agricultural storm water discharges and return flows from irrigated agriculture. See EPA: http://water.epa.gov/polwaste/nps/whatis.cfm.

recirculating Cooling systems in which a water molecule, if it does not evaporate, can be used directly or

cooling system indirectly to cool steam flowing in the condenser. This can be water that flows more than once within the cycle of a wet-cooling tower or water that is discharged into a cooling pond for later withdrawal into the condenser.

return (flow) Same as discharge.

steam-electric A term often used to describe power plants that generate electricity using a steam (e.g., Rankine) cycle.

thermal plume The spatial extent of the heated discharge water extending from once-through cooling systems, approximately indicated by the water existing at some threshold temperature above the natural (ambient) water body temperature.

thermoelectric A term often used to describe electric generation power plants that operate as a heat engine. This is not meant to be confused with thermoelectric materials that generate electromotive force in a thermocouple (e.g., Seebeck or Peltier effect).

vapor plume The visible plume of water vapor that can appear exiting the top of wet-cooling towers.

withdrawal The water removed from a water body for beneficial use such as cooling water, boiler makeup water, ash sluicing, and dust suppression. See USGS Water Use Survey, EIA form 923, and Chapter 1 for diagrams and further discussion.