ELECTRIC POWER RESEARCH INSTITUTE

Clean Water Act Section 316(b) Closed-Cycle Cooling Retrofit Research Program Results Summary

2011 TECHNICAL REPORT

Clean Water Act Section 316(b) Closed-Cycle Cooling Retrofit Research Program Results Summary

1023453

Final Report, August 2011

EPRI Project Manager
D. Bailey

ELECTRIC POWER RESEARCH INSTITUTE
3420 Hillview Avenue, Palo Alto, California 94304-1338 ▪ PO Box 10412, Palo Alto, California 94303-0813 ▪ USA
800.313.3774 ▪ 650.855.2121 ▪ askepri@epri.com ▪ www.epri.com

DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

THE FOLLOWING ORGANIZATION(S), UNDER CONTRACTO TO EPRI, PREPARED THIS REPORT:

Maulbetsch Consulting

Veritas Economic Consulting

PwrSolutions, Inc.

URS Corporation

Cardno ENTRIX, Inc.

ASA Analysis & Communication, Inc.

NOTE

For further information about EPRI, call the EPRI Customer Assistance Center at 800.313.3774 or e-mail askepri@epri.com.

ACKNOWLEDGMENTS

The following organizations, under contract to the Electric Power Research Institute (EPRI), prepared this report:

Maulbetsch Consulting
770 Menlo Ave.
Suite 211
Menlo Park, CA 94025

Principal Investigator
J. Maulbetsch

Veritas Economic Consulting
1851 Evans Rd.
Cary, NC 27513

Principal Investigators
M. Bingham, J. Kinnell, D. Santoianni,
A. Miedema, S. Johnston

PwrSolutions, Inc.
2777 Stemmons Freeway, Suite 1520
Dallas, TX 75207

Principal Investigators
M. Sahni, S. Talati, C. Gibune

URS Corporation
335 Commerce Drive, Suite 300
Fort Washington, PA 19034-2623

Principal Investigator
J. Tramontano

Cardno ENTRIX, Inc.
10 Corporate Circle, Suite 300
New Castle, DE 19720

Principal Investigator
J. Webber

ASA Analysis & Communication, Inc.
5 Fairlawn Drive, Suite 205
Washingtonville, NY 10992

Principal Investigators
W. P. Dey, E. Perry, T. McConnell

This report describes research sponsored by EPRI.

This publication is a corporate document that should be cited in the literature in the following manner:

Clean Water Act Section 316(b) Closed-Cycle Cooling Retrofit Research Program Results Summary. EPRI, Palo Alto, CA: 2011. 1023453.

EPRI would like to acknowledge the support of the following organizations that supported its initial Closed-Cycle Cooling Retrofit Research Program:

AES Corporation
Ameren
American Electric Power
Arkansas Electric Cooperative
Constellation Energy
Consumers Energy
Dairyland Power
Dominion Generation
DTE Energy
Duke Energy
Dynegy
Entergy
Exelon
FirstEnergy Services
Great River Energy
Hawaiian Electric Company
Hoosier Energy
Los Angeles Department of Water & Power
Midwest Generation
Minnesota Power
Mirant
National Grid
NYISO
NRG
Omaha Public Power District
PHI
PPL Corporation
Progress Energy
PSEG Services Corporation
SCANA Corporation
Southern California Edison
Southern Company
Tennessee Valley Authority
We Energies

EPRI would like also like to acknowledge the following organizations for funding support of the study to evaluate the benefits of closed-cycle cooling retrofits:

AES Corporation
American Electric Power
Constellation Energy
Dominion Generation
DTE Energy
Duke Energy
Entergy
Exelon
GenOn
Hawaiian Electric Company
Luminant
Midwest Generation
Minnesota Power
Nebraska Public Power District
NYISO
Northeast Utilities
Progress Energy
Pacific Gas and Electric
Southern Company
Tennessee Valley Authority
We Energies
Xcel Energy

PRODUCT DESCRIPTION

The Electric Power Research Institute (EPRI) has investigated the implications of a potential U.S. Environmental Protection Agency (EPA) Clean Water Act §316(b) rulemaking if it establishes closed-cycle cooling retrofits for facilities with once-through cooling as "best technology available" (BTA) for fish protection. This report provides a summary of the results of five studies that comprise EPRI's Closed-Cycle Cooling Retrofit Research Program. These studies evaluated the cost, both financial and economic; electric system reliability; and adverse environmental and social impacts of retrofits as well as the benefits of closed-cycle cooling retrofits.

Results and Findings

EPRI estimates that there are 428 facilities potentially subject to retrofit requirements, based on their use of greater than 50 million gallons per day (MGD) of once-through cooling water. These facilities are capable of generating approximately 312,000 MW of electricity—60,000 MW by 39 nuclear facilities and 252,000 MW by 389 fossil facilities. While closed-cycle cooling is commonly employed for new generating facilities, the cost of retrofitting existing facilities can be significantly higher, due to the need to relocate existing infrastructure, the requirement to locate cooling towers relatively long distances from the condensers, or other factors depending on the facility. EPRI estimated the capital cost, cost of lost revenue for extended downtime, cost of energy to operate cooling towers, and the cost of lost generation output due to the cooling inefficiency to be $95 billion. The cost and generation inefficiencies can make retrofitting economically impractical for many units. This is particularly the case for older units with low capacity utilization. The study determined this would not likely be the case for baseloaded nuclear facilities, but estimated that some 26,000 MW of fossil generation is potentially at risk of premature retirement due to economic considerations.

Based on an analysis of five electric system reliability regions, an estimated $7 billion in expenditures for replacement capacity would be required in order to maintain an adequate reserve margin in three of the five regions. Additional expenditures would be required to avoid localized thermal overloads or voltage violations. The willingness to pay to avoid adverse environmental and social impacts associated with retrofits is estimated to be $33 million annually, principally including the cost of increased greenhouse gas emissions, noise, view degradation, roadway fogging, and decrease in man-made debris removal, while the monetized economic benefit to commercial and recreational fisheries is estimated to be in the range of $14 million to $23 million annually.

Challenges and Objective(s)

Section 316(b) of the Clean Water Act establishes statutory requirements for fish protection at cooling water intake structures (CWISs). In 2004 the U.S. EPA established a rule for implementing §316(b) for existing CWISs using >50 MGD. The rule was withdrawn by the EPA following a legal challenge and subsequent Second Circuit Court ruling. The EPA proposed a revised rule for existing facilities in April 2011 that included consideration of three additional options, two of which were based on closed-cycle cooling as BTA. The EPA plans to issue a final rule in mid-2012, and potentially, any of the four options could be selected for the final rule.

Applications, Value, and Use

Information in this report is intended to provide the EPA with technical information for Clean Water Act §316(b) policy development and future rule compliance efforts by the power industry, regulatory agencies, and the public.

Data in this summary report provide regulators, the industry, and other stakeholders with information on the financial impacts of closed-cycle cooling as BTA. Additionally, this report provides information concerning the cost, adverse environmental and social impacts, and electric system impacts as well as the benefits of closed-cycle cooling as BTA.

Approach

EPRI used a variety of approaches in the course of this research program including industry surveys, questionnaires, literature reviews, and analytical models. A wide range of technical experts was used to cover the complex engineering, biological, economic, and environmental issues considered in this study. The detailed approaches and methods are provided in the five EPRI reports generated by the research program (1022491, 1022751, 1023174, 1022760, and 1023401).

Keywords

Clean Water Act §316(b)
Closed-cycle cooling
Cooling towers
Cooling water intake structure (CWIS)
EPA
Fish protection

ABSTRACT

This report summarizes the results of the Electric Power Research Institute's (EPRI's) Closed-Cycle Cooling Retrofit Research Program, which consists of five studies that evaluate the cost of retrofits, financial and economic impacts; impacts to electric system reliability; adverse environmental and social impacts of retrofits, and the benefits in reducing impingement and entrainment mortality if the Environmental Protection Agency (EPA) designates closed-cycle cooling as "best technology available" (BTA). This report provides a summary of the study's approach and important findings of each of the five studies. It also provides as estimate of potentially affected facilities as well as their flow and generation capacity (that is, MWs produced). The results of the research are discussed in context with both the proposed rule and other options being considered by the EPA. The study results estimate that the capital cost, lost revenue for extended outages, closed-cycle cooling energy inefficiencies, and new generation necessary to maintain system reliability would cost in excess of $100 billion. Some 26,000 MWs of fossil energy would be prematurely retired. The estimated willingness to pay to avoid closed-cycle cooling environmental and social impacts is approximately $33 million per year, while the estimated economic benefits to commercial and recreational fisheries are approximately $16 million per year.

EXECUTIVE SUMMARY

In 2007, after the remand of the §316(b) Phase II Rule, the Electric Power Research Institute (EPRI) initiated the Closed-cycle Cooling Retrofit Research Program to estimate the potential impacts to the steam electric power generation industry should closed-cycle cooling be designated as Best Technology Available (BTA) for facilities currently using once-through cooling. This research focused on considerations the Second Circuit Court identified in its January 2007 decision that could be used by EPA in making the BTA determination relative to closed-cycle cooling. These considerations included 1) whether the industry could bear the cost of closed-cycle cooling, 2) impacts to energy production and efficiency and 3) adverse impacts associated with the closed-cycle cooling technology. Subsequent to the Supreme Court decision in 2009 that EPA could consider the benefits relative to the cost, EPRI added an additional project to estimate the benefits. The EPA evaluated four options for the proposed rule issued in the Federal Register April 20, 2011[1]. While the preferred option is not based on closed-cycle cooling as BTA, for entrainment mortality reduction closed-cycle cooling could be required on a case-by-case basis. Two of the other three options EPA considered are based on closed-cycle cooling as BTA. The results of the EPRI research program can be summarized as follows:

- EPRI estimates that 39 nuclear and 389 fossil facilities have at least one unit using once-through cooling in excess of 50 MGD that are affected by the proposed Rule. These units have the potential to generate an estimated 312 GWs of electricity. This number does not include smaller facilities using more than 2 MGD that could be required to retrofit with closed-cycle cooling under Best Professional Judgment (BPJ) as proposed in Option 1 of the Rule. However, most of these low flow power generation facilities already use closed-cycle cooling. The number of impacted facilities in EPRI's facility list differs by only a few percent from that assumed by EPA in the proposed Rule.
- For Option 1, EPA's preferred option, EPRI's research results support that consideration of cost, feasibility, benefits, financial, electric system reliability and adverse social and environmental impacts of closed-cycle cooling are all potentially important technical issues to consider in making a case-by-case BTA determination.
- EPA Options 2 and 3 are based on closed-cycle cooling as BTA. The results of EPRI research on the national implications of closed-cycle cooling as BTA are directly relevant to those options. Key findings relative to these options include:
  - The cost of these options would be in excess of $100 billion or an annualized cost of $7.5 billion. EPRI identified ten categories of costs to be considered should closed-cycle cooling be designated as BTA; these were divided into three groups:

[1] Federal Register, Vol. 76, No. 76, p, 22174, April 20, 2011.

- Facility specific costs - Seven cost categories are associated with facility specific cost considerations. In terms of these costs, EPRI estimated a closed-cycle cooling retrofit cost of $95 billion that included the capital cost, heat rate penalty, cost of energy to operate the cooling towers and lost revenue for extended outages should all once-through facilities be required to retrofit with closed-cycle cooling. Two cost categories (permitting cost and labor, and chemical and maintenance cost to operate the cooling towers) are not considered significant in terms of affecting the national retrofit cost estimate. The cost of capital to finance the retrofits, while potentially significant, was not estimated.
- Cost to the industry – EPRI estimated a partial replacement power cost to maintain adequate reserve margins as a result of premature facility retirements and the energy loss associated with the operation of cooling towers. Based on an analysis of five reliability regions, EPRI estimated that a potential capacity replacement cost of just under $7 billion may be required to maintain an adequate reserve margin in three of the five regions evaluated. For the other two reliability regions, plans for new generation were sufficient to maintain adequate reserve margins. While potentially significant, EPRI did not estimate the cost of electric system upgrades that may be required to maintain system security by avoiding localized thermal overloads and/or voltage violations on transmission lines.
- Social costs – EPRI estimated the national willingness to pay (WTP) cost to avoid the adverse environmental and social impacts of closed-cycle cooling to be $33 million per year. However, this estimate does not include cost estimates for a number of impacts including, but not limited to, evaporative freshwater loss, noise impacts to threatened and endangered species, disposal of solid waste from cooling tower basins and visible plumes in the vicinity of airports.

– Infeasibility of retrofitting some facilities – The study estimates that approximately 5% of the facilities may not be able to retrofit due either to physical space constraints or environmental permitting issues.

– Premature unit retirements – The study estimates some 26,000 MW could potentially be prematurely retired due to the economic impracticality of retrofitting. It is also important to note that the analysis did not consider the potential cumulative impacts of other environmental regulations under consideration relative to air quality and waste handling. The combination of such regulations in addition to closed-cycle cooling as BTA could significantly increase the number of facilities at risk of premature retirement. It is important to note the analysis did not consider the impact of multiple environmental regulations not under consideration by EPA and multiple requirements such as requirements for Clean Air Act mercury controls and elimination of wet ash handling could significantly increase the number of MWs at risk of premature retirement.

– Adverse social and environmental impacts – In addition, to the WTP estimates to avoid impacts, the study provides quantitative estimates for the following impacts:

- Emission of 29,800 tons/yr of fine particulates
- Use of 25,000 metric tons/yr of chlorine for biofouling control

- Evaporative freshwater loss of 500 billion gallons/yr (i.e., more than sufficient to meet the 2009 population potable freshwater needs of the state of Illinois).
- 861 tons/yr of debris that will no longer be removed on intake structures. This debris poses a water navigation safety risk and risk to the health of marine mammals and aquatic birds.
- The equivalent of 163 million tons/yr of greenhouse gas emissions.

– Benefits of retrofits – EPRI estimated the annual benefit potentially associated with the impingement and entrainment (I&E) reductions associated with closed-cycle cooling to be approximately $16 million annually with a lower bound estimate of $13.8 million/year and an upper bound estimate of $22.7 million/year. Based on this annual benefit estimate range, the corresponding present value over 30 years at a 3% discount rate is $270.5 million, $313.5 million, and $444.9 million with annualized (present value divided by 30) values of $9.02, $10.45, and $14.83 for the lower, midpoint, and upper values. Approximately 40% of the benefit is associated with impingement mortality reduction while 60% is associated with entrainment reduction. EPRI identified three uncertainties where the benefit is underestimated, eight uncertainties that overestimate benefits and seven uncertainties that could either over or underestimate the benefits.

– Benefits of Retrofits relative to the Adverse Social and Environmental Impacts of Closed-cycle Cooling – The monetized benefits estimated to range between $13.8 and $22.7 million/yr appear to be on the same scale as the estimated WTP $33 million/yr to avoid those impacts. EPA is engaged in studies to determine WTP to avoid the non-use impacts of once-through cooling and similar studies could be employed to assess many of the closed-cycle cooling impacts not monetized in this study.

– Cost of Closed-cycle Cooling Relative to the Benefits – Using the mid-point between EPRI's upper and lower bound present value (PV) estimates (i.e., $ 313.5 million) and EPRI's estimated cost to be in excess of $100 billion (assume $100 billion), the cost of EPA Options 2 and 3 would be on the order of 183 times greater than the benefit. It is important to note that while the benefits have not been fully valued due to the associated uncertainties, neither have the adverse environmental and social impacts of retrofits been fully valued.

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1
INTRODUCTION AND BACKGROUND

Closed-cycle Cooling Retrofit Research Program Overview

After remanding §316(b) Phase II Regulations in 2007, the U.S. Environmental Protection Agency (EPA) proposed revised regulations to implement §316(b) of the Clean Water Act (CWA) in April 2011[2]. This proposal was in response to a remand of the prior Phase II Rule by the Second Circuit Court Decision (Decision) issued on January 25, 2007. The Second Circuit Court, in remanding the §316(b) Phase II Rule to EPA, specifically directed the agency to clarify its basis for not designating closed-cycle cooling as Best Technology Available (BTA). In the Decision, the Second Circuit said the EPA could not base the BTA determination on the cost of the technology relative to fish protection benefit provided, but the Court identified several factors that could be used to reject closed-cycle cooling as BTA. Specifically, these factors included:

1. The ability of industry to reasonably bear the cost of the technology
2. The impacts on energy efficiency and production
3. The adverse environmental impacts associated with the technology.

Based on the Second Circuit decision, EPRI initiated the Closed-cycle Cooling Research Program in 2001 to provide EPA with technical information relative to the three factors identified that could be considered by the Agency in making the BTA determination for 316(b).

Subsequently, the issue of whether or not EPA could consider cost relative to benefits was reviewed by the Supreme Court and on April 1, 2009 the Court ruled that EPA could consider cost relative to benefits for this rulemaking. As a result of that ruling, EPRI commenced a new study to estimate the national benefit of closed-cycle cooling as BTA.

The objective of EPRI's Closed-cycle Cooling Retrofit Research Program is to provide technical data and information for consideration by EPA in making the §316(b) BTA determination relative to the three factors identified by the Second Circuit Court as well as the cost relative to the benefits based on the Supreme Court Ruling.

§316(b) Legislative and Regulatory Background

Section 316(b) was included as part of the 1972 Clean Water Act amendments. The statutory provision required that "the location, design, construction and capacity of cooling water intake

[2] Federal Register, Vol. 76, p. 22174, April 20, 2011.

structures reflect the best technology available for minimizing adverse environmental impact". EPA's first issued regulations to implement this statutory requirement in 1977. However, those regulations were challenged and remanded back to EPA by the Fourth Circuit Court in 1977 on procedural grounds. As a result of litigation in 1993, EPA initiated work on a new rule and subsequent to a consent decree, set a schedule for trifurcation of the rulemaking into three phases; specifically, Phase 1 would address New Facilities; Phase II, existing power plants; Phase III, existing power plants not covered by Phase II and other industrial facilities.

The Phase II rule addressed existing power plants that used in excess of 50 million gallons of water per day. The Phase II regulations were issued on July 9, 2004 (Federal Register, Vol. 69. No. 131). The rule was challenged by a number of environmental groups and six northeastern states as well as several power companies and the Utility Water Act Group (UWAG). The challenges were consolidated into a single case which was argued before the United States Court of Appeals for the Second Circuit on June 8, 2006 and a decision was issued on January 25, 2007. The Decision remanded significant portions of the Rule back to EPA. The Court determined that use of restoration measures and the Cost-Benefit Test could not be used as compliance options. Two Rule provisions, the Cost-Cost Test and the Technology Installation and Operation Plan (TIOP) were remanded back to EPA for failure to provide adequate opportunity for public review and comment. Perhaps most importantly, the Court remanded to EPA the determination of BTA. Relative to BTA, the Court raised a number of issues that EPA would have to address in the promulgation of a revised Rule that included:

- Closed-cycle Cooling as BTA – The Court said that EPA may have based its determination that closed-cycle cooling was not BTA for existing facilities at least in part, due to the cost of the technology relative to the environmental benefits. The Court pointed out that consideration of the environmental benefits was not allowed for the Phase II Rule. The Court remanded this determination back to EPA for clarification. The Court clarified that EPA could consider factors that included industries' ability to bear the cost, impacts to energy production and efficiency and adverse impacts associated with retrofits in making this determination.
- Use of "Best Performing" Technology – The Court upheld EPA's use of performance standard ranges. However, the Court determined that facilities must use the "best performing" technology in the performance standard range rather than the most cost-effective technology.
- Consideration of Cost – The Court ruled that EPA could consider the cost of technologies to a limited extent in the BTA determination. The first issue is whether or not facilities can bear the cost of the technology. The second was limited to the use of cost-effectiveness. On this point, the Court ruled that if there was an overlap in the expected environmental performance ranges of two best performing technologies, the facility could select the most cost-effective option rather than the one that had the potential for higher performance.

As a result of the Decision, UWAG, Entergy Corporation, and Public Service Gas and Electric Company each filed a timely petition for Certiorari with the Supreme Court for review of the Decision. The Supreme Court determined that it would not review the Decision regarding use of restoration measures; however, it decided it would review the Decision regarding consideration of compliance costs relative to the environmental benefits. The Supreme Court's final decision was issued on April 1, 2009. The Supreme Court upheld EPA's use of the Cost-Benefit Test in the Rule. This provision of the Rule allowed facilities to compare the cost of technologies to meet performance standards to the benefit that would be achieved. Facilities were not required to install technologies that had a cost that was significantly greater than the benefit.

In response to the Second Circuit Decision (Decision), EPA issued a memorandum dated March 20, 2007, to EPA's Regional Offices announcing withdrawal of the Phase II Rule. This was followed by a notice in the Federal Register on July 9, 2007. Specifically, the memorandum and Federal Register notice stated the withdrawal of the Rule was a result of the Decision's impact on the overall compliance approach. EPA determined that so many of the Rule's provisions were affected by the Decision that the overall Phase II approach was no longer workable for compliance. The memorandum and Federal Register notice further directed EPA Regional Offices and delegated states to implement §316(b) in NPDES permits on a Best Professional Judgment (BPJ) basis, until the Decision issues were resolved.

EPA signed the revised 316(b) proposed regulations for existing facilities on March 28, 2011 and they were published in the Federal Register on April 20, 2011.

EPA 316(b) Proposed Rule Relative to Closed-cycle Cooling

EPA's proposed rule applies to all facilities (both steam electric and manufacturing) that use over 2 million gallons per day (MGD) of cooling water. The agency considered four options for the proposed rule that are summarized as follows:

Option 1 - The preferred option established separate requirements for existing once-through cooled facilities and new units at existing facilities. Closed-cycle cooling was proposed as BTA for new units at existing facilities. Requirements for new facilities are generally very similar to those in the Phase I Rule for new facilities. For existing electric power generating units, EPA proposed BTA separately for impingement and entrainment. Impinged organisms are those that cannot pass through a 3/8 inch mesh sieve (i.e., screen) while entrained organs are those that would pass through a 3/8 inch mesh sieve. EPA proposed two alternatives for impingement compliance. In Alternative 1, BTA for impingement is based on modified traveling screens with a fish return for finfish. Facilities choosing this option must reduce impingement by 69% monthly and 88% annually which is verified by biological monitoring. In Alternative 2, facilities must not exceed a design through screen velocity of 0.5 fps. BTA for impinged shellfish in tidal waters is based on the reduction that can be achieved by a properly deployed and maintained barrier net. There are additional requirements to address fish entrapment that may be an issue for some facilities.

For entrainment, BTA is to be determined by the permitting authority on a case-by-case basis for all facilities withdrawing more than 125 MGD actual intake flow (AIF). Such facilities are required to submit peer reviewed information on all life stages of entrained species, the cost and performance of technologies to reduce entrainment (including both closed-cycle cooling and alternative entrainment reduction technologies and operational measures), environmental impacts resulting from technologies, the benefits of technologies and any impacts of technologies to regional electric supply. Facilities withdrawing between 2 MGD design intake flow (DIF) and 125 MGD AIF are not required to submit the peer reviewed information but are also potentially subject to entrainment requirements on a case-by-case basis.

Option 2 – The same Option 1 requirements apply for new units at existing facilities. Also the same Option 1 requirements apply for impingement reduction for all facilities withdrawing more than 2 MGD. However, flow reduction commensurate with closed-cycle cooling is BTA for all facilities that withdraw more than 125 MDG DIF. In addition, the entrainment reduction information requirements for Option 1 do not apply since closed-cycle cooling is designated as BTA.

Option 3 – The same Option 1 requirements apply for new units at existing facilities as well as the Option 1 requirements for impingement reduction. However, for this option, closed-cycle cooling is designated BTA for all facilities that withdraw more than 2 MGD.

Option 4 - The same Option 1 requirements apply for new units at existing facilities. For impingement, the uniform Option 1 requirements would only apply to facilities that withdraw 50 MGD or more of cooling water. Facilities using between 2 MGD and 50 MGD DIF would be subject to impingement reduction requirements on a case-by-case basis and all facilities withdrawing more than 2 MGD would be subject to entrainment reduction requirements on a case-by-case basis.

In summary, closed-cycle cooling was established as BTA for new units at existing facilities under all four options. For existing units, closed-cycle cooling for entrainment could be required on a case-by-case basis for all facilities over 2 MGD under Options 1 and 4. For Options 2 and 3 closed-cycle cooling is BTA for facilities using more than 125 MGD AIF and 2 MGD DIF, respectively. Impingement reduction is required under all four options but is based on compliance using options other than closed-cycle cooling.

EPRI Closed-cycle Cooling Research Relative to the 316(b) Proposed Rule

The EPRI Closed-cycle Cooling Retrofit Research Program was initiated in 2007 as a result of the Second Circuit Court Decision. The research assumed that regulated facilities under the proposed rule would be those covered under the remanded Phase II Rule (i.e., those with a DIF of 50 MGD or more). The following five technical reports were generated based on that assumption:

1. Closed-cycle Cooling System Retrofit Study – Capital and Performance Cost Estimates (EPRI 2010)
2. Evaluation of the National Financial and Economic Impacts of a Closed-cycle Cooling Retrofit Requirement (EPRI 2011a)
3. Maintaining Electric System Reliability Under a Closed-cycle Cooling Retrofit Requirement (EPRI 2011b)
4. Net Environmental and Social Effects of Retrofitting Power Plants with Once-through Cooling to Closed-cycle Cooling (EPRI 2011c)

5. National Benefits of a Closed-cycle Cooling Retrofit Requirement (EPRI 2011d)

In terms of EPA's proposed Option 1 and Option 4, closed-cycle cooling is determined on a case-by-case basis making it difficult to estimate exactly how many facilities nationally would be required to retrofit. While EPA preferred Option 1 does not mandate closed-cycle cooling as BTA, facilities using more than 125 MGD AIF are required to submit an evaluation of that technology for consideration by the permitting authority in making the entrainment BTA determination. Specifically these facilities must submit:

- Comprehensive Technical Feasibility and Cost Evaluation Study – This study must evaluate the feasibility and cost of closed-cycle cooling; this is the subject of EPRI's closed-cycle cooling retrofit study (EPRI 2010).
- Benefit Valuation study – Facilities must submit a study that evaluates both the monetized and non-monetized benefits of closed-cycle cooling; this is the subject of EPRI's national benefits of closed-cycle cooling retrofits study (EPRI 2011d).
- Non-water Quality and Other Environmental Impacts Study – This study must include an evaluation of reliability impacts as well as the environmental impacts associated with closed-cycle cooling; these are the subjects of EPRI's financial and economic impacts of retrofits study (EPRI 2011a); EPRI's maintaining electric system reliability study (EPRI 2011b); as well as EPRI's environmental and social impacts of retrofits study (EPRI 2011c).

While the national retrofit estimates provided in the EPRI studies are not directly relevant to Option 1, the information provided in them is directly relevant to the information requirements and EPA's discussion and rational for including consideration of these issues in making the entrainment BTA determination on a case-by-case basis.

Two EPA Rule Options (Options 2 and 3) are based on closed-cycle as BTA but affect a somewhat different population of facilities than assumed by EPRI in its research and modeling. EPRI identified 428 once-through cooled facilities potentially affected by a retrofit requirement (39 nuclear and 389 fossil). Under Option 2, only those facilities withdrawing more than 125 MGD DIF would require use of closed-cycle cooling as BTA. The EPRI cost of retrofits (EPRI 2010) report provides retrofit cost estimates separately for nuclear and fossil facilities. Since all of the once-through cooled nuclear facilities use more than 125 MGD DIF there is no change for the estimated costs to retrofit these facilities under Option 2. For the fossil facilities using 125 MGD DIF rather than 50 MGD DIF as the closed-cycle cooling retrofit basis, this reduces the number of affected fossil facilities from 389 to 322 (a reduction of 67 facilities). However, these are the smallest facilities on the list and retrofit costs are directly related to the size of the facility. The 67 small facilities represent only 2.9% of the total once-through cooled fossil facilities based on flow, and only 2.8% of the total MW generation. The effect of not including these 67 facilities in the nation-wide analysis results in a relatively small reduction in the retrofit cost estimates and other implications of a closed-cycle cooling BTA requirement under EPA Option 2.

Under EPA Option 3, the proposed rule would cover additional steam electric facilities not included in the EPRI analysis based on facilities that use >50 MGD DIF. As with Option 2, there would be no effect on the study results for nuclear facilities, since all once-through cooled nuclear facilities use more than 50 MGD. While EPRI does not have a good estimate of the number of fossil power generation facilities that use less than 50 MGD, EPRI believes many of these facilities already employ closed-cycle cooling and therefore do not affect research results (EPA estimated 148 in scope facilities had closed-cycle cooling[3]). In terms of once-through cooled fossil steam generation facilities that do not use closed-cycle cooling, EPRI believes the number to be small and based on the lack of significance for excluding 67 facilities using the 125 MDG DIF criteria, there is likely to be no significant impact on the overall research results.

Summary Report Organization

Section 2 of the report provides a list of Phase II facilities potentially impacted if closed-cycle cooling were determined to be BTA and a comparison of the EPRI list to the number of generating facilities assumed by EPA in the proposed rule. Section 3 presents an analysis of retrofit costs, factors that can make retrofitting difficult, as well as the energy penalty and retrofit feasibility issues for some facilities. In Section 4, based on Section 3 cost estimates, the financial impacts of retrofits are summarized and estimates are provided of the number of units and MWs potentially at risk of premature retirement due to their inability to bear the cost of a retrofit. Section 5 provides estimates of the reduction in generation as a result of unit shutdowns as well as the energy penalty. Section 6 provides both qualitative and quantitative information on the potential environmental and social impacts associated with closed-cycle cooling while Section 7 provides a discussion of the benefits of closed-cycle cooling that includes the monetized recreational and commercial fishing benefits and uncertainties associated with those estimates. Only limited references are provided in this summary report, however, detailed references are provided in each of the five EPRI technical reports.

[3] Federal Register, Vol. 79, p. 22191, Exhibit IV-1, April 20, 2011.

2

§316(B) AFFECTED PHASE II FACILITIES

Introduction

In order to estimate the national cost, financial, energy supply and environmental impacts of closed-cycle cooling as BTA, as well as the potential benefits, it is important to have an accurate list of the potentially affected facilities. EPRI's list was based on the EPA Phase II Rule that included facilities using more than 50 MGD of cooling water.

Phase II Facility List Development Methodology

EPRI's list was developed starting in 2007 with the EPA list provided as Appendix B (pg 41680 of Federal Register, Vol. 69, No. 131 dated July 9, 2004) and the Department of Energy (DOE) lists[4]. EPRI then sent the draft list to the industry for review by EPRI members and to other power plant owners through a number of industry trade organizations that included the Edison Electric Institute, Utility Water Act Group, National Rural Electric Cooperative Association and the American Public Power Association. EPRI requested identification of any retired facilities or facilities that would have been subject to the Phase II Rule that were not on the draft list. In addition, EPRI had visited or performed 316(b) related work at over 125 facilities. For approximately 60 facilities for which the status was not clear, EPRI made phone calls to the facility or facility owners to seek clarification relative to the facility Phase II status. EPRI sent out its list to its members and through the industry trade associations again in 2010 to ensure the list was as accurate as possible and a number of facilities were deleted due to retirement. In addition to the facility name, the list contained data on flow, MW, waterbody type, name of source waterbody and state where facility is located. EPRI requested information on the accuracy of all information listed for each facility.

For EPRI's financial impacts study, it was important to have unit specific information including capacity utilization since the decision on whether or not it makes economic sense to retrofit at a facility is made on a unit specific basis. It is not uncommon for fossil facilities with multiple units to have some with relatively high capacity utilization and others that operate only during periods of peak energy demand due to their age and higher operating costs. EPRI also requested that the data provided include only those units that used once-through condenser cooling, since a number of facilities have both closed-cycle and once-through cooled units on site. Over 95% of the nuclear facilities and 75% of the fossil facilities provided verified information. This included verification of unit specific once-through cooling water flow, an essential metric for estimating

[4] Three DOE Databases included: 1. EIA Schedule 767, EIA Schedule 860 and EIA Schedule 906-920.

retrofit cost. Verification of information was provided through one of three mechanisms that included:

1. Providing a completed cost of retrofit worksheet (see Chapter 3 for worksheet details)
2. Submitting an Excel data sheet that requested unit specific flow, MW and capacity utilization information
3. Data provided directly to EPRI as a result of 316(b) compliance support services

Facilities and Uncertainties

Attachment A provides EPRI's final list of Phase II facilities used in all analysis. The final list was completed in December 2010. The list includes 428 facilities, 39 nuclear and 389 fossil (note the list contains three sites that have both nuclear and fossil units). These facilities generate approximately 312,000 MWs of electricity (252,000 MWs fossil and 60,000 MWs nuclear). Some important considerations relative to the list for the purpose of the study include:

- For a facility to be on the list it must have an active NPDES permit. There are a small number of facilities that may not have operated in the last year or more but maintain an active NPDES permit. Two facilities have NPDES permits for once-through cooling that are still under construction. EPRI is also aware of at least two facilities on the list that were retired after the list was finalized in December 2010.
- Some of the listed facilities identified as having once-through cooling systems withdraw cooling water from freshwater lakes and may in fact already be withdrawing from waters that are considered part of a closed-cycle cooling system and not "waters of the U.S." Facilities not withdrawing from "waters of the U.S." would only be subject to §316(b) if the makeup waters for the freshwater lakes as withdrawn from "waters of the U.S."
- A small number of facilities on the list use helper cooling towers during the summer to meet thermal discharge limits. Some of these facilities may be able to retrofit at a relatively low cost as a result incorporating the helper towers into the retrofit design if closed-cycle cooling were designated as BTA.

EPRI List Compared to EPA Proposed Rule List

EPRI did not have access to the EPA list to allow a direct comparison of facilities. However, in the April 2011 proposed existing facility rule, EPA identified 559 steam electric generators it considered would be affected by the rule (i.e., used more than 2 MGD). However, EPRI's list of 428 facilities was limited to facilities that had at least one, once-through cooled unit, while the EPA list includes facilities that contained solely closed-cycle cooled units. EPRI excluded such facilities, since the EPRI study is focused on facilities that are at risk of having to retrofit to closed-cycle cooling. EPA's Exhibit IV-1 in the proposed rule preamble indicates that 148 of the 559 facilities were completely closed-cycle cooled facilities. If these 148 facilities are subtracted from EPA's list of 559 facilities, the total number of facilities with at least one once-through unit is 411 which compares closely to the EPRI list of 428 facilities (i.e., a difference of 17 facilities or only 4%).

3
COST OF CLOSED-CYCLE COOLING RETROFITS

EPRI estimated the potential cost of closed-cycle cooling retrofits if closed-cycle cooling was designated BTA and presented the results in *Closed-cycle Cooling Retrofit Study: Capital and Performance Cost Estimates* (EPRI 2010).

This analysis estimates the costs of retrofitting with closed-cycle cooling systems, those existing steam-electric power plants that were designed for built with, and are currently operating on once-through cooling. Establishing the cost of retrofitting is important in making the determination of whether or not facilities could bear the cost and resulting potential impacts to energy production and delivery. The primary objective of the study was to estimate the national capital cost of retrofitting all the Phase II facilities. Three other significant cost elements were estimated. These are the cost of replacement energy during the time that plants are unable to operate during the retrofit process, the annual cost of additional operating power required for closed-cycle cooling and the cost of heat rate penalties resulting in reduced plant efficiency and output incurred because of thermal limitations of closed-cycle cooling. The affected facility population was assumed to be the 428 facilities discussed in Chapter 2. The study also identified a number of facilities that were considered to be infeasible to retrofit due to physical space limitations.

EPRI identified ten cost elements that would make up the total cost to retrofit should closed-cycle cooling be designated BTA for the industry. These cost elements were:

1. Cooling tower capital cost (hardware and construction cost)
2. Cost of capital to finance the project
3. Revenue loss for extended outages to tie in the cooling tower system
4. Energy penalty (lost revenue due to energy requirements for cooling tower fans and pumps)
5. Heat rate penalty (lost revenue due to reduced condenser cooling efficiency with a cooling tower compared to once-through cooling)
6. Operating and maintenance cost (labor and materials to operate and maintain the closed-cycle system)
7. Permitting costs
8. Cost of replacement power generation (replacement power to offset loss of generation due to premature facility retirement in response to economic or permitting issues)
9. Cost of electric system upgrades (upgrades to the electric system due to generation losses from the energy penalty, heat rate penalty, prematurely retired facilities as a result of shifting voltage loads to the transmission system that may not be designed for the new loads)

10. Environmental and social costs (monetized costs to avoid environmental effects of closed-cycle cooling such as noise, drift, habitat loss, increased consumptive water loss, etc.)

Cost elements 1-7 are facility specific costs that would reasonably be considered by each facility in making the economic decision on whether or not to retrofit. Cost elements 8 and 9 are costs that would be borne by the industry as a whole and cost element 10 represent social costs that would be borne by populations in proximity to the closed-cycle system.

The cost of retrofits report provides cost estimates for elements 1, 3, 4, and 5. Cost elements 2 and 8 are discussed in Chapter 4; cost element 9 is discussed in Chapter 5; and cost element 10 is discussed in Chapter 6. EPRI did not make quantitative cost estimates for elements 6 and 7, however these costs are considered relatively small compared to the other cost elements and would not be expected to significantly affect the national cost of a closed-cycle cooling retrofit requirement.

Study Approach

The study focused on developing a methodology that accounts for the highly site-specific nature of cooling system retrofit costs for use in estimating total national costs of a closed cycle retrofit program. It is well accepted that the retrofitting of existing once-through cooled plants with closed-cycle cooling is significantly more costly than installing closed-cycle cooling at new, greenfield facilities. The methodology consisted of three steps. The first two address the estimation of cost at individual plants; the third aggregates and extrapolates individual plant estimates to a national total:

1. Step 1 established a likely range of capital costs for a plant simply as a function of the circulating water flow rate in the original once-through cooling system. Separate correlating equations were determined for fossil and nuclear plants.
2. Step 2 placed an individual plant cost within the likely range of costs based on the perceived degree of difficulty for retrofitting that plant. The degree of difficulty was based on site-specific information obtained from a cost-estimating worksheet survey of over 185 facilities. Estimates were made for approximately 125 facilities. Distributions of Phase II facilities representing ranges of degrees of difficulty from “Easy” to “More Difficult” (for fossil plants) and “less Difficult” to “More Difficult” (for nuclear plants) were extrapolated. 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 estimated the national costs by aggregating the number of plants and their cooling water flow rates in each category of difficulty using the cost vs. flow rate correlations developed in Step 1.

In addition, estimates were made of three other significant cost elements. These were the cost of energy replacement during the time a plant is offline for retrofitting; the annual cost of additional power required for operating the closed cycle-related equipment; and the annual cost associated with the facility heat rate penalties resulting from the inherent reduced heat dissipation ability of closed-cycle cooling systems.

Estimates of the amount of outage time required to retrofit nuclear and fossil plants were based on a limited number of independent engineering studies for nuclear plants and information from a few recent retrofits at fossil plants.

Study Results

Cost ranges

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

Retrofit Capital Cost ($) = Cost coefficient ($/gpm) x Circulating water flow (gpm)

were developed for fossil and nuclear plants.

The cost coefficients for the four degrees of difficulty for fossil plant retrofits are:

Easy:	**$181/gpm**
Average:	**$275/gpm**
Difficult:	**$405/gpm**
More Difficult:	**$570/gpm**

The cost coefficients for the two degrees of difficulty for nuclear plant retrofits are:

Less difficult:	**$274/gpm**
More difficult:	**$644/gpm**

Degrees of difficulty

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 retrofit projects of varying degrees of difficulty. Based on discussions with plant personnel and architect-engineering firms and the application of professional judgment, the list of 11 factors given in Table 3-1 was compiled which were believed to represent the most important factors for determining site-specific degrees of difficulty.

Table 3-1
Factors influencing degree of difficulty

Factor	Description
1	The availability of a suitable on-site location for a tower(s)
2	The separation distance between the existing turbine/condenser location and the selected location for the new cooling tower(s)
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 make-up water
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

Space constrained sites

At some sites, the retrofitting of closed-cycle cooling is simply infeasible due to a lack of space for a cooling tower. In the majority of cases, these sites are located in dense urban locations where there is simply no space available on the site to locate a cooling tower of sufficient size. Often, the surrounding land is occupied with valuable urban properties such as apartment or office buildings. In a few cases, at rural sites, the existing site itself has no room for a cooling tower. In these rural locations, there may be open, undeveloped adjacent land that is not owned by the facility. In such cases, it may be possible to acquire additional land, unless it is a sensitive area such as unique habitat or a state or federal park.

In addressing this issue, EPA says that "Land upon which to construct cooling towers may be difficult or impossible to obtain." and that "The Agency did not include these potential costs in its analyses."[5] Therefore, in this study any costs for land acquisition were similarly not included, and the assumption was made that if new land must be acquired in order to site a tower, the site is considered to be "infeasible for retrofit". Seven sites, out of the 125 sites for which site-specific analyses were performed, were deemed "infeasible" on the basis that no space was available for a cooling tower.

Operating power costs

In addition to the initial capital cost, other ongoing costs are incurred as a result of a closed cycle cooling system retrofit. Major costs include increased operating power for cooling tower

[5] Federal Register, Vol. 69, p. 41605, July 9, 2004.

equipment and reduced plant thermal efficiency and related capacity resulting from higher turbine exhaust pressures normally imposed by closed cycle cooling.

The additional operating power consumed by a closed-cycle cooling system consists of water pumping power and fan power:

- The additional pumping power ranges from a minimum of 0.25% to a maximum of approximately 0.55% of plant output or 2.5 to 5.5 MW for a 1,000 MW plant.
- Similarly, fan power requirements average about 0.6% of plant power or 6 MW for a 1,000 MW plant.
- The sum of the additional operating power required is, therefore, estimated to range from about 0.85 to 1.7% of plant output or 8.5 MW to 17 MW for a 1,000 MW plant. It is important to understand that this power is consumed internally by the facility and thus, is power that is not available for sale to the public.

If the cooling system is re-optimized, the usual result is that the circulating water flow is reduced to nominally one-half of what it had been in the original once-through system. Similarly, the cooling tower will have nominally half the cells that would be required if the system had not been re-optimized with a corresponding reduction in the fan power requirement. Therefore, the estimated additional operating power for re-optimized systems would range from 4.3 to 8.5 kW/MW.

Efficiency and capacity penalty costs

Conversion of a once-through cooling system to a closed-cycle cooling system using a wet cooling tower frequently results in an increase in the achievable turbine backpressure for most of the year and a corresponding loss of plant efficiency and output. The size of the loss is strongly dependent on source water temperature and the atmospheric temperature and humidity at the site. As such, it is extremely difficult to generalize. The annual average generation output loss at sites most adversely affected lies between 2 and 4%. Losses on the hottest days of summer at some sites can be higher.

While nearly all plants will incur some penalty on an annual average basis, some will incur no penalty or even experience increased efficiency or output during the hottest periods of the year. This is the case in situations where

- the summertime source water temperature exceeds the temperature of return “cold” water from a cooling tower to the condenser,
- the plant thermal output is curtailed to meet once-through cooling discharge temperature limitations or
- low summertime flows in the source waterbody limit plant operations.

Instances of high summertime source water temperatures were considered and the slight performance improvements were included in the calculation of a national average penalty.

However, there was no available information on the frequency, duration or magnitude of the other two effects and thus, they were not considered in the analysis.

Cost of retrofit –induced outages

The other significant cost is the loss of revenue during outages required for the installation of the retrofit cooling system. There is very little information available to establish national averages. However, based on some recent engineering studies and discussions with staff at plants where actual retrofits had been performed, a set of assumed downtimes for nuclear plants, baseloaded fossil plants and other fossil plants were used to develop national estimates for the replacement energy cost of outages due to retrofits. Additional information on the need for extended outages at many facilities is provided in Attachment B.

Using EPRI's database of 428 facilities, a comparison of EPA and EPRI extended outage assumptions determined that the overall net present value (NPV) cost of extended outages is similar (within ~8.3%). Based on a cost of $35/MWh, the EPA estimate (EPA assumed an average 7 month outage) would be $9.7 billion for nuclear facilities using the EPRI list of nuclear facilities compared to EPRI's estimate of $8.3 billion for the nuclear facilities. For fossil facilities EPRI's estimate of $8.6 billion was higher than the EPA $5.8 billion estimate using the EPRI fossil facility list. EPA assumed an outage of 4 weeks/facility while EPRI's estimate was based on a combination of capacity utilization and degree of retrofit difficulty. The total estimated downtime cost of lost revenue is $15.5 billion for EPA and $16.9 billion for EPRI.

National cost estimate

Extrapolation to national totals

The number of plants, total capacity and circulating water flow information for in-scope Phase II fossil and nuclear power plants is summarized in Table 3-2 for both fossil and nuclear facilities.

Table 3-2
Capacity and water flows at Phase II Facilities

Plant Type	No. of plants	Total capacity	Total circulating water flow
		MW	gpm
Fossil	389	252,392	139,506,944
Nuclear	39	59,931	42,788,889
Total	428	312,323	182,295,833

If all Phase II plants are assumed to have the same distribution of degrees of difficulty as was found for the 125 plants analyzed on a site-specific basis, the national cost to retrofit all Phase II plants is approximately $95 billion (Table 3-3).

Table 3-3
National costs for all Phase II plants categorized by source water type.

Plant Type	Source Water	Capacity	Water Flow	Costs					
				Capital	Operating Power	Heat Rate Penalty	Downtime	Annualized Cost	Net Present Value
		MW	GPM	$ millions	$ millions	$ millions	$ millions	$ millions	$ millions
Nuclear	Great Lakes	6,000	3,840,000	$1,760	$13	$16	$740	$200	$2,860
	Lakes/Reservoirs	20,000	13,990,000	$6,420	$46	$60	$2,700	$740	$10,430
	O/E/TR	22,000	17,615,000	$8,090	$58	$75	$3,400	$940	$13,140
	Rivers	12,000	7,344,000	$3,370	$24	$31	$1,420	$390	$5,480
	Total Nuclear	60,000	42,789,000	$19,640	$141	$182	$8,270	$2,280	$31,920
Fossil	Great Lakes	27,000	14,242,000	$4,330	$44	$54	$920	$480	$6,460
	Lakes/Reservoirs	61,000	32,831,000	$9,980	$100	$124	$2,120	$1,110	$14,890
	Oceans/Estuaries/ Tidal Rivers	70,000	41,923,000	$12,750	$128	$158	$2,710	$1,410	$19,010
	Rivers	94,000	50,511,000	$15,360	$155	$191	$3,260	$1,700	$22,910
	Total Fossil	252,000	139,507,000	$42,420	$427	$527	$9,010	$4,700	$63,270
All plants	Total Phase II	312,000	182,296,000	$62,060	$568	$709	$17,280	$6,970	$95,190

As discussed in Section 1.3 and 1.4 of this report, EPA Options 2 and 3 were considered as a basis for the Rule and each identified closed-cycle cooling as BTA. Option 2 required facilities using more than 125 MGD DIF to use closed-cycle cooling as BTA. This dropped 67 fossil facilities from EPRI's list (no change in nuclear facilities) of facilities employing once-through cooling. This reduced the number of fossil facilities by 17%. However, since these were the smallest facilities on the list in terms of flow and MWs, this reduced the overall fossil cooling water flow by only 2.9% and the MWs by 2.8%. In terms of the effect this action had on the cost estimates, Tables 3-5 and 3-6 provide the cost estimates for the Option 2 adjusted scenario (for comparison, see Tables 3-2 and 3-3 which provide results for facilities using over 50 MGD). The effect on EPRI's national cost estimate is a reduction of $3.7 billion.

Table 3-4
Capacity and water flows at Phase II Facilities

Plant Type	No. of plants	Total capacity	Total circulating water flow
		MW	Gpm
Fossil	322	247,000	133,889,000
Nuclear	39	60,000	42,789,000
Total	361	307,000	176,677,000

Table 3-5
National costs for all Phase II plants >125 MGD categorized by source water type.

Plant Type	Source Water	Capacity	Water Flow	Costs: Capital	Operating Power	Heat Rate Penalty	Downtime	Annualized Cost	Net Present Value
		MW	GPM	$ millions	$ millions	$ millions	$ millions	$ millions	$ millions
Nuclear	Great Lakes	6,177	3,840,278	$1,760	$13	$16	$742	$204	$2,862
	Lakes/Reservoirs	19,917	13,989,583	$6,420	$46	$60	$2,703	$744	$10,433
	O/E/TR	22,040	17,615,278	$8,090	$58	$75	$3,404	$937	$13,143
	Rivers	11,797	7,343,750	$3,370	$24	$31	$1,419	$391	$5,477
	Total Nuclear	59,931	42,788,889	$19,640	$141	$182	$8,269	$2,276	$31,915
Fossil	Great Lakes	27,614	14,305,604	$4,350	$43	$53	$901	$463	$6,434
	Lakes/Reservoirs	62,030	32,899,816	$10,005	$98	$121	$2,072	$1,065	$14,796
	O/E/TR	69,256	41,331,431	$12,568	$123	$152	$2,603	$1,337	$18,588
	Rivers	88,027	47,351,653	$13,012	$141	$174	$2,982	$1,435	$19,908
	Total Fossil	246,928	135,888,503	$39,935	$406	$500	$8,558	$4,300	$59,725
All plants	Total Phase II	306,859	178,677,392	$59,575	$546	$682	$16,827	$6,576	$91,640

Validation of estimates

The cost estimates in the analysis were compared, where possible, with independent retrofit cost estimates provided by the plants which had been generated by experienced engineering firms or plant engineering departments. There are 35 plants for which both independent cost information and adequate plant/site descriptions were available on which to base a degree of difficulty estimate. Typical agreement between these estimates for these 35 cases was +/-25% although some differed by as much as 50%. Comparisons were also made between the total retrofit costs for the group of 35 plants and for two subgroups within the 35; namely, California coastal plants and 9 plants for which very complete cost detail had been provided The agreement in the comparative total costs between the large group and both sub-groups was within 10%. This indicates that the methodology used in this study has no significant bias toward either higher or lower costs in the estimate of the national total cost. It is noted that these comparisons could be done only for the capital cost component. No plant-specific information was available to validate the other three cost elements.

4
FINANCIAL AND ECONOMIC IMPACTS

EPRI estimated the potential financial and economic impacts if closed-cycle cooling was designated BTA and presented the results in Evaluation of the National Financial and Economic Impacts of a Closed-cycle Cooling Retrofit Requirement (EPRI 2011a). Designating closed-cycle cooling as BTA would alter the technology and economics of existing facilities that currently use once-through cooling. Some owners would decide to prematurely retire their units rather than retrofit, while others would retrofit and operate in the post-regulation marketplace. The outcomes associated with these compliance and operational decisions ultimately register in the financial performance of the electricity industry, the industry's environmental footprint, and the economic welfare of electricity industry employees, consumers, and shareholders.

Study Approach

The results presented in the study arise from a simulation of electricity markets assuming closed-cycle cooling was designated as BTA. The simulation model employed a mathematical representation of economic conditions and generating unit operations including engineering cost estimates for retrofitting with closed-cycle cooling. Engineering cost estimates were developed as part of EPRI's companion capital cost of retrofits study (EPRI 2010). In the simulation of electricity markets, owners of once-through cooled facilities elect to install the new cooling systems if they expect the present value of the future stream of profits with closed-cycle cooling to exceed the costs of installing and operating the plants equipped with closed-cycle systems. The costs associated with conversion to closed-cycle cooling included in the analysis are the capital costs of cooling towers, energy requirements for cooling towers (i.e., energy penalty), and financing costs. Additional costs that could be incurred with closed-cycle cooling, such as extended outage costs, permitting costs, and environmental and social costs, were not evaluated. Table 4-1 presents the costs included and excluded in the study. Several of these costs are at the industry or societal level, and would thus not impact a company-specific compliance decision. Of the excluded costs that could affect the decision to retire a generating unit, changes in heat rate and permitting costs are highly site-specific and difficult to quantify.

Table 4-1
Closed-cycle Cooling Costs Included and Excluded in the Analysis

Included Costs	Excluded Costs
Capital cost to retrofit with cooling towers	Heat rate changes
Energy penalty associated with parasitic load	Permitting costs
Financing costs	Labor and chemicals cost
	Extended outage costs
	Replacement power
	Transmission upgrade costs
	Environmental/social costs

The modeling tool used for this project, the Environmental Policy Simulation Model (EPSM) was custom-built to support the EPRI closed-cycle cooling research program. The EPSM is designed to juxtapose a With Closed-Cycle Regulation scenario against the "Baseline" scenario. Differences in economic metrics between scenarios are identified to determine the economic impacts of a closed-cycle cooling retrofit regulation. The EPSM is a mathematical simulation model. It employs a computer-based representation of the complex systems that underlie wholesale electricity markets. The model incorporates relationships and available data in a computational structure that simulates the behavior of these systems.

Important features considered in developing EPSM include its ability to support the quantification of impacts to electricity production, efficiency, and consideration of criteria noted in EPA's *Guidelines for Preparing Economic Analyses* (EPA 2010), hereafter EPA Guidelines. With respect to the former, independent system operator (ISO) membership is identified that is consistent with available power cases. This allows mapping of results from EPSM directly to power flow simulation models to support detailed power flow modeling that can identify transmission security implications. In addition, EPSM specifies generation units and cooling towers precisely rather than aggregating components into model plants. The explicit characterization of each generating unit in a particular manner is important for changing parameters to reflect the implications of installing cooling towers, such as parasitic load. In addition, although load periods are used in this analysis, EPSM is calibrated to results from an hourly unit commitment simulation.

Features of EPSM consistent with EPA Guidelines include compilation of an industry profile, specification of a clearly defined Baseline, specification of the implications of the regulation, prediction of responses to the new regulation within a partial equilibrium analysis, and comparison of results to identify the implications of the regulation. The compilation of an industry profile is based on ISO membership as well as regulated status and unit characteristics identified by generating unit owners. Employing this approach also increases precision because unit- and plant-level information can be evaluated by owners and improved. As recommended by EPA Guidelines, EPSM includes a clearly specified Baseline. The model does not forecast the Baseline; rather, it uses external forecasts of fuel prices, electricity prices, and loads. This allows assessing the sensitivity of model results to Baseline assumptions. With the Baseline clearly defined, the physical implications of the regulation are imposed on each unit's input-output curve while financial implications (i.e., retrofit costs and changes in fixed costs) are entered as a stream of annual costs. EPSM predicts responses to the regulation using a partial equilibrium approach. In this context "partial equilibrium" refers to simulating changes in electricity prices and quantities while holding other factors constant, such as fuel prices and employment. The partial equilibrium modeling context simulates owner decision-making over both the short run and long run. In the short run, EPSM re-dispatches generating units to maximize unit-level profits in each period subject to the equilibrium requirement that the demand for electricity is satisfied. The model evaluates operating decisions over the long run based on new equilibrium electricity prices and quantities, as well as new projections of unit operating behavior and profitability.

The simulation model extends into the future by 30 years (2016–2045) to reflect an expected capitalization period for the retrofits. Although the cost burden and electricity price impacts of potential, additional environmental regulations (e.g., regulations on coal ash disposal and mercury) would be considered in compliance and operational decisions, the impact of these other regulations is not included in this analysis. In addition, the timeline for compliance with the rule and the phase-in period for retrofits could affect the decision to prematurely retire. This analysis assumes that all retrofits are completed by 2016.

This simulation model evaluates impacts in five U.S. electricity markets: Pennsylvania New Jersey Maryland Interconnection (PJM), Electric Reliability Council of Texas (ERCOT), Independent System Operator-New England (ISO-NE), Midwest Independent System Operator (Midwest ISO), and the New York Independent System Operator (NYISO). To provide insight into the economic impacts in the remaining regions of the country, a statistical model was estimated to examine the relationship between unit-specific characteristics and the premature retirement decisions predicted for the existing facilities subject to the retrofit requirement within the five modeled regions. The results of the statistical model were used to predict the premature retirement for the remainder of the nation's electricity generating units subject to the closed-cycle cooling retrofit requirement. These include facilities located in SERC Reliability Corporation (SERC), Florida Reliability Coordinating Council (FRCC), Southwest Power Pool (SPP), Western Electric Coordinating Council (WECC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), and the Reliability First Corporation (RFC) regions.

The analysis relies on projections of fuel prices for coal, petroleum, natural gas, and uranium for 2016 going forward. Fuel price projections over the modeled time period assume a two- to three-percent annual increase (varies by region). Simulation modeling results depend upon fuel costs, as well as other parameters, including unit heat rates, operating costs and capacity constraints, electricity demand, and compliance costs. The sensitivity of model results to fuel prices assumptions has not been quantitatively assessed. However, the highest sensitivity with respect to fuel costs and model results relates to the relationship between natural gas and coal prices. Natural gas-fired units account for 6 percent of regulated generation, and coal-fired units account for 61 percent of regulated generation. Historically, coal prices have been much lower than natural gas prices; this is reflected in model fuel-price projections used for the analysis.

Study Results

Table 4-2 summarizes the results of the analysis. As the table shows, of the 1,008 regulated units, 214 units are predicted to experience cost impacts that would render them unprofitable in a post-regulation marketplace, placing approximately 26,058 megawatts (MW) of capacity at risk for premature retirement. The table also shows that relative fuel costs are an important consideration as the units most likely to retire prematurely are those that run on oil and gas, which historically have been the most expensive fuels. For oil, 36 out of 74 regulated units (49 percent) are predicted to retire prematurely. Of 252 regulated gas units, 124 (49 percent) are predicted to retire prematurely. By comparison, 54 of 625 regulated coal units (9 percent) are expected to retire prematurely, and with these assumptions none of the 57 regulated nuclear units are predicted to retire prematurely. It is also important to note that the analysis did not consider the potential cumulative impacts of other environmental regulations under consideration in relative to air quality and waste handling. The combination of such regulations in addition to closed-cycle cooling as BTA could significantly increase the number of facilities at risk of premature retirement.

Table 4-2
Summary of Number of Units and Capacity at Risk of Premature Retirement by Fuel Type Assuming Closed-Cycle Cooling was Designated as 316(b)

Fuel Type	Number of Regulated Units	Number of Units Predicted to Retire Prematurely
Oil	74	36
Gas	252	124
Coal	625	54
Nuclear	57	0
Total Units	1,008	214
Total Capacity	281,695 MW	26,058 MW
Average Capacity Factor	58%	19%

The analysis was conducted regionally. Table 4-3 presents the number of units and corresponding capacity at risk for premature retirement in each region. The table also presents the results of an alternative regulatory scenario. The sensitive waterbody scenario is an alternative regulatory option that would require closed-cycle cooling retrofits only for units located on waterbodies that are particularly sensitive to the effects of impingement and entrainment (IM&E). These include facilities located on oceans, estuaries, and tidal rivers.

Table 4-3
Summary of Number of Units and Capacity at Risk for Premature Retirement by Region

Region	All Waterbodies		Sensitive Waterbodies	
	Units at Risk of Premature Retirement	Capacity at Risk (MW)	Units at Risk of Premature Retirement	Capacity at Risk (MW)
PJM	21	3,250	17	2,826
ERCOT	25	5,458	5	1,187
ISO-NE	12	2,561	9	2,494
Midwest ISO	7	906	0	0
NYISO	11	3,325	11	3,325
SERC	38	3,044	8	590
FRCC	21	2,196	13	1,409
SPP	20	1,475	2	79
WECC	18	2,699	16	2,593
MRO[a]	8	328	0	0
RFC[a]	33	816	1	97
National Totals	214	26,058	82	14,600

Notes:
[a] The units in MRO and RFC represent units that are part of a NERC reliability region, but they are not part of an independent system operator. They therefore are not the total units in MRO or RFC, but are the units that are not included in either PJM or Midwest ISO.

The units predicted to retire prematurely tend to be less efficient (average heat rate of 11,412 Btu/kWh compared to 10,757 Btu/kWh), higher-fuel-cost (predominantly oil and gas), load-following (average capacity factor of 19 percent versus 58 percent) units. Many of these units operate primarily during Summer Shoulder, Peak, and SuperPeak time periods[6]. The estimated price impacts associated with the premature retirement of these units is consistent with the loss of load-following generation. Table 4-4 illustrates this result. Price increases arising from the premature retirement of regulated units occur primarily during periods modeled as Summer Peak and Summer SuperPeak. ERCOT also shows the potential for price increases in Spring/Fall Peak and Spring/Fall SuperPeak.

[6] These three periods make up 12.5 percent of the year in the economic model.

Table 4-4
Comparison of Predicted Price Increases by Load Period and Region

Percentage Price Increase by Load Period	EPSM Regions				
	PJM	ERCOT	ISO-NE	NYISO	MISO
Winter Baseload	1.09%	1.30%	0.00%	0.00%	0.00%
Winter Shoulder	1.36%	4.60%	0.00%	0.00%	0.00%
Winter Peak	1.43%	1.92%	0.00%	0.00%	3.20%
Winter SuperPeak	1.48%	4.81%	0.00%	0.00%	2.66%
Spring/Fall Baseload	1.00%	1.77%	0.00%	0.00%	0.00%
Spring/Fall Shoulder	1.21%	3.89%	0.00%	0.00%	0.00%
Spring/Fall Peak	1.32%	14.24%	0.00%	0.00%	0.00%
Spring/Fall SuperPeak	1.42%	38.61%	0.00%	0.00%	1.61%
Summer Baseload	0.78%	1.34%	0.67%	0.00%	1.41%
Summer Shoulder	2.18%	26.25%	0.00%	2.97%	2.17%
Summer Peak	3.07%	32.63%	46.85%	14.74%	1.59%
Summer SuperPeak	2.85%	34.38%	52.45%	12.87%	3.03%

5 IMPACTS TO ENERGY PRODUCTION AND EFFICIENCY

The EPRI study on the potential impacts to energy production and efficiency of designating closed-cycle cooling as BTA are presented in Maintaining Electric System Reliability Under a Closed-cycle Cooling Retrofit Requirement (EPRI 2011b). As summarized in Chapter 4, a national closed-cycle cooling retrofit requirement would alter the technology and economics of existing electric generating facilities that currently use once-through cooling. Some units would prematurely retire rather than retrofit while others would retrofit and continue to operate but incur an energy penalty as a result of the cooling towers. The outcomes associated with these compliance and operational decisions affect energy production and efficiency.

This study evaluates the implications that a national closed-cycle cooling retrofit requirement, such as described in EPA Options 2 and 3, would have for maintaining U.S. electrical system reliability. Although numerous other environmental regulatory actions could affect the compliance and retirement decisions of once-through cooled generating units, this study only evaluates the reliability implications of a closed-cycle cooling regulation.

Study Approach

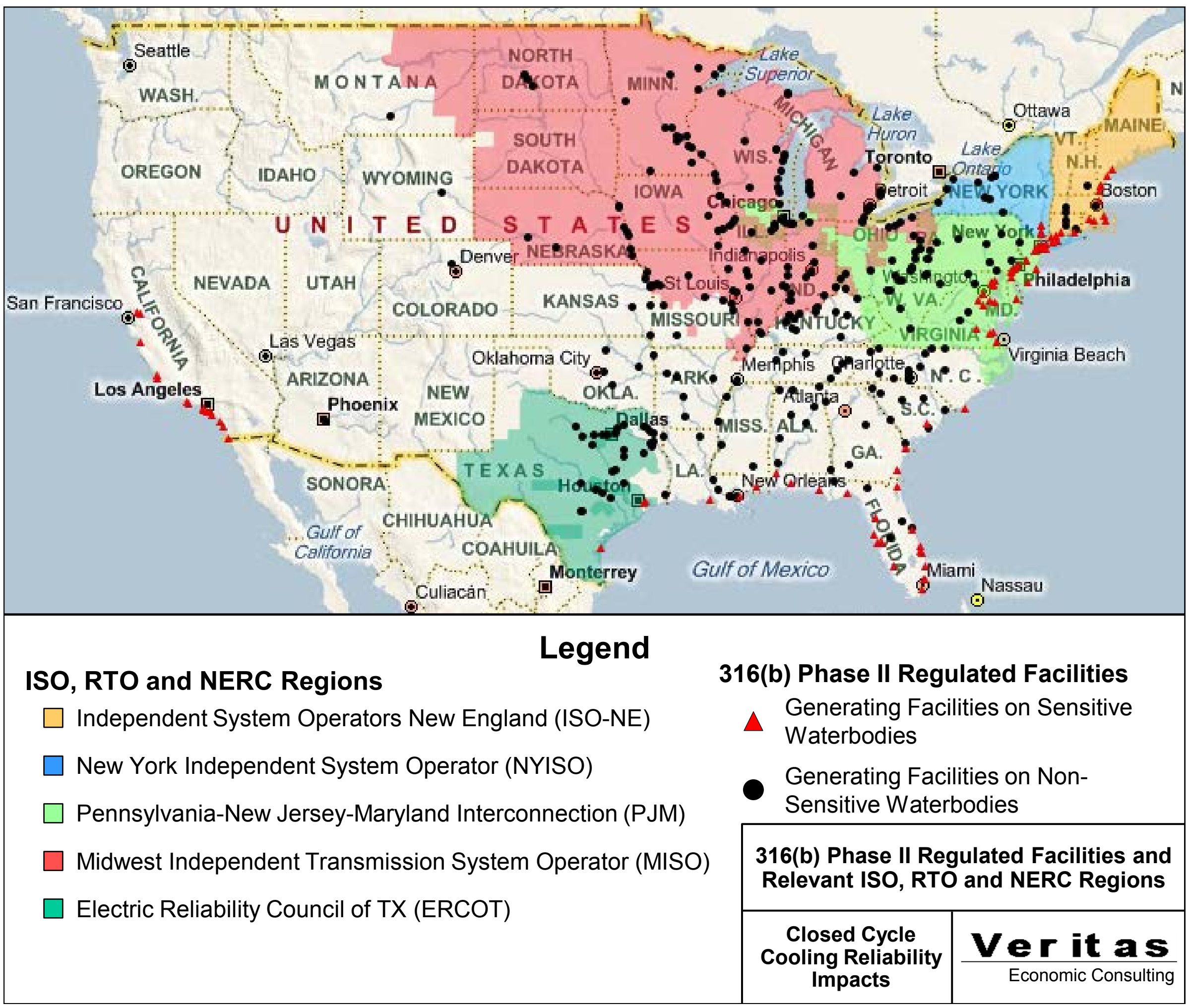
The evaluation was guided by the North American Electric Reliability Corporation (NERC) standards. NERC is certified by the Federal Energy Regulatory Commission (FERC) to establish and enforce reliability standards for the bulk-power system. NERC enforces mandatory reliability standards with all U.S. owners, operators, and users of the bulk power system. NERC divides electrical system reliability into two components: adequacy and security. NERC defines adequacy as the ability of the electric system to supply electricity, taking planned and forced outages into account. Security, as defined by NERC, is the ability of the electrical system to withstand sudden disturbances, such as unanticipated loss of electrical system components.

Simulations of electrical system reliability impacts are aids for planning—**not predictions**. Generation retirement requests typically require a reliability impact study, which assesses the impact of the unit's retirement on reliability of the grid. If planned transmission enhancements more than sufficiently relieve reliability issues associated with the retiring plant or there are no major reliability impacts associated with the retiring plant, the retirement is approved. If the unit is needed to ensure reliability, it is placed under a Reliability Must Run (RMR) contract or similar arrangement. In this case, the de-activation of the unit is delayed, which allows time to undertake transmission system improvements which will ensure reliability.

The study simulated impacts to both adequacy and security using simulation models of electrical systems for five reliability regions:

- Pennsylvania New Jersey Maryland Interconnection (PJM)
- Electric Reliability Council of Texas (ERCOT)
- Independent System Operator-New England (ISO-NE)
- New York Independent System Operator (NY-ISO)
- Midwest Independent System Operator (MISO).

Figure 5-1 identifies the location of all of the electricity generating stations using once-through cooling at volumes >50 MGD and formerly subject to the EPA 316(b) Phase II Rule and the regions evaluated.



Note: Affected facilities in Alaska, Hawaii, Guam, and Puerto Rico are not shown.

Figure 5-1
316(b) Facilities and ISO, RTO, and NERC Regions Evaluated in the Reliability Analysis

The analysis employed the "without regulation" (Baseline) and "with regulation" (With Closed-Cycle Regulation) approach that is central to regulatory and economic impact analyses. Regions and subregions develop target capacity margins based on the characteristics of electrical systems. Because the 2016 capacity margin projections for studied regions do not include reductions in generation resources attributable to the retrofit requirement, these capacity margins are defined as Baseline. Modeled regulation-induced impacts to these Baseline capacity margins are a key metric for evaluating the adequacy aspect of reliability with respect to a closed-cycle cooling requirement. The With Closed-Cycle Regulation capacity margin estimates are developed by modeling decreases in capacity associated with early retirements induced by the regulation and parasitic loads (i.e., energy requirements to operate cooling towers) imposed by cooling towers. Premature retirement decisions under the With Closed-Cycle Regulation scenarios are predicted by imposing regulatory costs in the Environmental Policy Simulation Model (EPSM). EPSM is an engineering-economic model that simulates regional electricity markets. Within this model, mathematical simulations are used to identify market outcomes, including generation, electricity prices, and closed-cycle cooling retrofit (shutdown) decisions. This model is linked by data and calibration to the transmission model data employed in the reliability study. Subtracting capacity that is lost due to the retrofit requirement reveals the impacts to capacity margins uniquely associated with the retrofit requirement.

Modeling was conducted for each region under both a Sensitive Waterbodies (i.e., facilities withdrawing from oceans, estuaries, and tidal rivers) and an All Waterbodies regulatory scenario (69 *Fed. Reg.* 131, 41575–41693). Under the Sensitive Waterbodies regulatory scenario, only open-cycle facilities with design capacity greater than 50 million gallons per day (MGD) located on oceans, tidal rivers, and estuaries are subject to the regulation. Under the All Waterbodies scenario, all current open-cycle units with design capacity greater than 50 MGD are subject to the regulation. Based on results of economic modeling and research into each modeled region, impacts to 2016 capacity margins were evaluated for each region. EPRI notes that for Option 2 EPA indicated the permitting authority would have some discretion in terms of the timeframe for retrofits but that fossil facilities would have to come into compliance within 10 years (i.e., 2022 assuming a final Rule in 2012) and nuclear facilities would have to comply within 15 years (i.e., 2027). Clearly this would affect study results in terms of existing and planned for the extended compliance dates considered by EPA for compliance.

Study Results

Table 5-1 provides a summary of the results of the adequacy evaluation.

Table 5-1
Summary of Adequacy Evaluation

Category	Region	2016 Target Capacity Margin	2016 Capacity Margin without Regulation	Modeled Capacity Reduction (MW)	2016 Capacity Margin With Closed-Cycle Regulation
All Waterbodies	PJM	15.3 %[a]	23.5 %[a]	3,633	20.9 %
	ERCOT	13.75%[b]	13.57%[c]	5,683	5.4 %
	ISO-NE	18.0 %[d]	12.7 %[d]	2,640	3.7 %
	NYISO	18.0 %[d]	27.0%[e]	3,441	16.9 %
	MISO	15.9 %[f]	18.8%[f]	1,324	17.6%
Sensitive Waterbodies	PJM	15.3 %[a]	23.5 %[a]	2,943	21.4 %
	ERCOT	13.75%[b]	13.57%[c]	1,207	11.8%
	ISO-NE	18.0 %[d]	12.7 %[d]	2,563	4.0 %
	NYISO	18.0 %[d]	27.0%[f]	3,441	16.9 %
	MISO	15.9 %[f]	18.8%[f]	1,324	17.6%[g]

Results indicate that the least impact to capacity margins occurs in PJM and MISO. This is the case under both the Sensitive Waterbodies and All Waterbodies specifications. Both ERCOT and ISO-NE would experience significant impacts in that there could be relatively large capacity retirements that would push capacity margins below 2016 planning margins. In ERCOT, the Sensitive Waterbodies specification would reduce capacity impacts from 5,683 MW observed under the All Waterbodies scenario to 1,207 MW. NYISO would see a significant impact to its 2016 capacity margin under both regulatory scenarios; however, given that this region has a high 2016 planning margin, it would be pushed only slightly below the target capacity margin. It is also important to note that for all NERC Regions the analysis is based on assumed new generating currently planned, but not yet in place. Should planned capacity not be completed in the analysis timeframe the lack of generation adequacy would increase.

The cost of maintaining generation adequacy in the face of these impacts is estimated as the minimum of the following:

1. costs for complete offset of regulation-induced capacity losses and
2. costs for reaching 2016 target capacity margins.

Costs to maintain adequacy are estimated as the fixed costs of replacement generation in the form of combustion turbines and are depicted in Table 5-2.

Table 5-2
Costs of Maintaining Adequacy

Category	Region	2016 Target Capacity Margin	2016 Capacity Reduction	2016 Capacity Margin With Closed-Cycle Regulation	2016 Replacement Cost (Millions)
All Waterbodies	PJM	15.3 %[a]	3,633 MW	20.9 %	$0
	ERCOT	13.75%[b]	5,683 MW	5.4 %	$4,558
	ISO-NE	18.0 %[c]	2,640 MW	3.7 %	$2,117
	NYISO	18.0 %[c]	3,441 MW	16.9 %	$297
	MISO	15.9 %[d]	1,324 MW	17.6 %	$0
Sensitive Waterbodies	PJM	15.3 %[a]	2,943 MW	21.4 %	$0
	ERCOT	13.75%[b]	1,207 MW	11.8 %	$968
	ISO-NE	18.0 %[c]	2,563 MW	4.0 %	$2,056
	NYISO	18.0 %[c]	3,437 MW	16.9 %	$293
	MISO	15.9 %[d]	1,324 MW	17.6 %	$0

[a] PJM (2011)
[b] ERCOT (2010c)
[c] North American Electric Reliability Corporation (NERC) (2010). According to NERC, ISO-NE does not have a target capacity. Therefore, NERC's reference 2014 reserve margin (18.0%) is used as the target capacity for ISO-NE. We use NERC's reference 2014 reserve margin (18.0%) as the target capacity for NYISO. This is also the 2010–2011 installed reserve margin approved by FERC and NY State Public Service Commission.
[d] MISO (2010a)

In addition to the adequacy assessments, alternating current (AC) security assessments were conducted for each region. These assessments are consistent with NERC planning criteria and similar to the type of evaluation performed when a generating unit plans to retire. All relevant transmission elements within the regional systems modeled were monitored in these assessments. Hourly demand, generation resource-specific dispatch, economic data, and firm power transfers are incorporated into the model. Simulations are conducted under anticipated peak load conditions using a power flow simulation tool (PowerWorld). The Baseline specification includes the regulated units with current capacities; the With Closed-Cycle Regulation case includes closures and de-rates identified from economic modeling. Security Constrained Optimal Power Flow (SCOPF) methodologies were employed to identify thermal overloads and voltage violations under both cases. In these simulations, when system elements operate beyond their designed thermal and voltage limits, they are noted as transmission system violations and tabulated. Incremental transmission system violations between the Baseline and With Closed-Cycle Regulation case are identified as the metric of regulatory impact to security. Potential generation and transmission system enhancement-related remedies are identified by considering the location and severity of violations in the context of replacement capacity requirements identified in the adequacy assessment and existing regional transmission expansion plans

(RTEP). Additional load-reducing activities, including demand response and energy efficiency initiatives, could play a role in ensuing reliability (NERC 2011); however, these strategies were not evaluated for this study.

PJM

For PJM, under the "All Waterbodies" regulatory scenario, thermal overloads and low-voltage violations were observed on lines feeding service territories for several companies. These overloads and violations may be mitigated to a large extent by PJM's six proposed transmission enhancement projects, however, these would not address potential local thermal overloads that were also observed in these load-intensive regions. These overloads arise from a lack of adequate local transmission connectivity that appears in the "With Closed-Cycle Regulation" scenario. Thus implementation of these higher-level transmission projects is unlikely to alleviate thermal stress at this level of the system. In addition, low-voltage issues arising from reactive power deficits are observed in some of the load-intensive regions. Because the ability to transmit reactive power long distances is limited, implementation of these major transmission system projects would only partially alleviate the low-voltage violations observed.

These results indicate that under modeled conditions and with consideration of proposed transmission enhancements, some combination of replacement generation, local transmission system enhancement, and reactive power support would be required to maintain security in PJM. The adequacy assessment indicates that new capacity is not required to maintain 2016 capacity margins. Because new capacity is not required local transmission upgrades and local reactive power support would be potential solutions. Reactive power support can be provided by the numerous types of equipment that have been developed to support grid modernization.[7] The most cost-effective type and location of reactive power support is typically identified through a detailed steady state and dynamic security assessment of voltage stability with consideration of the costs and characteristics of the various types of equipment available.

ERCOT

In ERCOT under the "All Waterbodies" regulatory scenario, thermal overloads and low-voltage violations are observed on the system that feeds the load centers in the North region. These results are similar but less severe than those observed in a similar simulation study performed by ERCOT System Planning.[8] Under the "Sensitive Waterbodies" specification a limited number of relatively minor thermal overloads are observed on this system.

The majority of planned transmission improvements in ERCOT were included in the power-flow modeling. For this reason, the planned transmission developments would do little to alleviate the potential transmission system overloads and/or voltage violations. For the "All Waterbodies" regulatory scenario, the nature and level of the overloads suggest that upgrading the North

[7] For example, modern flexible AC transmission system components (FACTS) elements have sophisticated voltage control capabilities.
[8] This difference is attributed to financial model differences, which led to higher shutdowns from a closed-cycle cooling requirement in the ERCOT study.

region's radial transmission systems would alleviate thermal overload concerns. These upgrades could somewhat mitigate low-voltage issues in this region. However, localized reactive power support in the vicinity of the load centers in the North region may still be needed to account for the reactive support lost due to premature retirements. Some of this support could come via grid modernization. However, the adequacy assessment indicates a need for replacement capacity in ERCOT. Because generation provides both active and reactive power, locating this capacity in the North region could help alleviate both thermal and voltage concerns.[9]

ISO-NE

In ISO-NE, under the "All Waterbodies" scenario, the premature retirements and capacity de-ratings result in thermal overloads on the 345 kV systems in Southeastern Massachusetts (SEMA). Thermal overloads also occur on the 230–115 kV systems in several northeastern states.

Numerous 345 kV and/or 115 kV transmission system enhancements are proposed in Southern New England. A majority of these are still in the planning process and are not included in the assessment. Under the conditions modeled, transmission upgrades would be required to support increased power imports into several regions. In addition, the local transmission system in the regions of in several states would require bolstering to avoid thermal overloading concerns. With respect to reactive power, low-voltage violations in NH are potentially correctable through generation re-dispatch. Low-voltage violations in Maine and SEMA appear to result from lost reactive power support attributable to premature retirements. Given the degree and number of transmission system overloads observed in several subregions implementation of the majority of planned transmission enhancements in Southern New England would likely be required to alleviate these concerns. Also, the adequacy assessment indicates that new generation would be required to maintain capacity margins. Locating this generation in these regions could lessen the need for enhanced transmission to these areas.

MISO

When the closed-cycle cooling requirement is modeled, thermal stress is observed on the transmission system in a number of service subregions. With respect to voltage violations under contingency conditions, the FirstEnergy (FIRSTENE) region presents a concern, with a significant number of low-voltage violations resulting from closed-cycle cooling retrofit requirements. Additional reactive power support would be needed within FIRSTENE in order to maintain reliability in the region. ALTE also has numerous voltage violations; however, these are high-voltage violations that may be alleviated with appropriate generation re-dispatch and would be somewhat ameliorated by proposing transmission projects in the ALTE regions. However, the other areas with identified transmission overloads are located in the East (METC and ITC) and relatively distant from proposed transmission enhancements and therefore would realize little benefit in alleviating the stress on the transmission system for these subregions.

[9] ERCOT (2011) includes the additional planning recommendation of "converting all retired generators to asynchronous condensers."

With respect to voltage violations, under modeled conditions, reactive power support would be required to maintain security in two subregions. The nature, magnitude, and locations of the reactive power support required in order to maintain system reliability following the incorporation of the "With Regulation" scenario would require a more detailed steady state and potential dynamic voltage stability/security assessment.

NY-ISO

In simulation modeling, significant thermal overloading is observed in the New York City (NYC) region and to a lesser extent in Long Island (LISLAND). A large number of low-voltage violations are observed at the 345 to 230 kV level in a number of sub-regions throughout the NY-ISO system.

Four transmission system enhancements that are proposed for NYC are not modeled in simulations but would be expected to alleviate a certain amount of the thermal stress with upgrades at the 345 kV level in NYC being particularly helpful. However, given the nature and extent of violations observed in these regions, the planned upgrades would not be enough to completely alleviate the thermal overloads observed in NYC and LISLAND.

With respect to voltage violations, a number of subregions are potentially areas of concern following the incorporation of the "With Regulation" scenario. Projects within regions experiencing low-voltage conditions may alleviate them by reducing active power flow (and therefore reactive power consumption) on heavily loaded lines and/or as a result of some planned transmission system upgrades. Even with this consideration, additional local reactive power support would be needed to replace the reactive capability lost due to unit shutdowns especially in the load-intensive areas of the Southeastern part of New York. The strategic placement of replacement generating capacity needed to maintain planning margins could potentially further alleviate thermal and voltage violations.

6
CLOSED-CYCLE COOLING RETROFIT SOCIAL AND ENVIRONMENTAL IMPACTS

The results of EPRI reseaRch on the potential environmental and social impacts associated with closed-cycle cooling are provided in: Net Environmental and Social Effects of Retrofitting Power Plants with Once-through Cooling to Closed-cycle Cooling (EPRI 2011c). The study objective was to quantify and monetize (to the extent possible) the environmental and social impacts of closed-cycle cooling retrofits. Where it was not possible to quantify or monetize these impacts, qualitative information is provided for rulemaking consideration. Also considered in this study was a review of potential environmental permitting and licensing requirements. Closed-cycle cooling structures are relatively large and the use of wet closed-cycle cooling results in discharges to "waters of the United States," air emissions, short term construction impacts, and waste generation. As a result, closed-cycle cooling retrofits can require a variety of federal, state, and local permits prior to construction. Such permits can impact the timing or overall feasibility of a closed-cycle cooling retrofit for any given site.

Study Approach

A comprehensive study of each of the over 400 facilities that have at least one unit with once-through cooling which would be subject to a Phase II rule was beyond the scope of the study. Therefore, the strategy for the study was to group the listed facilities according to critical variables and study at least one member in each group. The results could then be normalized and applied to the other facilities within the group or categories of facilities with similar characteristics (e.g., population). To estimate overall impacts on a national basis, the results for all groups were summed.

The original study approach was to evaluate representative facilities selected based on fuel type (nuclear and fossil), waterbody type, and climatic region. During the second phase of this study, seven facilities were selected to test (Beta Test) the quantification methodology. These seven facilities were given alphabetic identifiers: Beta Test Plant (BTP) A, BTPB, BTPC, BTPD, BTPE, BTPCA1, and BTPCA2 (two facilities located in California). Following the completion of the Beta Test, 17 additional facilities (i.e., the Representative Facilities, or 'RFs'), were selected and given identifiers RFF through RFV.

The key assumptions were that all facilities would retrofit with wet mechanical-draft cooling towers (the most commonly used cooling towers) and the study would rely on currently available data and information, with the exception of information generated from other EPRI Closed-cycle Cooling Retrofit Research Program studies and the results obtained from an EPRI Questionnaire . As part of the Program, EPRI distributed a questionnaire (a copy is provided as

Appendix D in EPRI 2011c) to all facilities affected by the Phase II Rule. Two hundred and nine facilities responded to at least a portion of the questionnaire and these results were used, when possible, in the analysis.

To estimate national impacts, the results of the Beta Test, evaluation of the RFs, and the EPRI Questionnaire results were normalized to the appropriate facility parameter (e.g., cooling water flow, population), if appropriate, and scaled to other facilities within each facility subset, where possible. National estimates were sub-totaled by source waterbody; namely, salt or brackish waterbodies (termed Ocean/Estuaries/Tidal Rivers [O/E/TR] in this study); Great Lakes and small rivers (GL/SM); and larger rivers, reservoirs or lakes (LR/RL).

During the Beta Test and evaluation of RFs, estimated effects of retrofit to closed-cycle cooling were monetized where there was an appropriate basis to generate a willingness to pay (WTP) estimate, to create a standard unit of comparison for different types of impacts. Annual WTP values in 2007$ generated and used in this report include:

- Terrestrial resources: loss of critical habitat = $200 per acre and $5,200 per acre (site-specific; only evaluated during the Beta Test)
- Terrestrial resources: drift effects on vegetation and soils = state-specific average annual rent per hectare of cropland based on U.S. Department of Agriculture data (only evaluated during the Beta Test)
- Water resource quantity and quality: debris removal = $1,132/ton trash calculated from existing data describing volunteer and government sponsored coastal and river clean-up programs
- Public safety and security: fogging/Icing on roadways: additional travel time = $8.91/hour, an average of U.S. Census Bureau and U.S. DOT data; additional cost of accidents due to fogging = $12,568/accident based on general estimates system of the U.S. National Highway Traffic Safety Administration data
- Quality of life: noise – region-specific values based on median home sales and a 0.4 percent reduction in housing value for each 1 db increase in noise
- Quality of life: viewshed – homeowners - region-specific value based on median home sales and a 0.4 percent reduction in housing value associated with the introduction of a plume to a viewshed; recreational – region-specific values for a recreational visit and a 1.8 percent reduction in the value of each recreational visit due to the introduction of a plume
- Greenhouse gas: incremental quantities of CO2 produced by fossil-fueled plants providing make-up power during nuclear plant outages to install close cycle cooling = $3.80 per ton of CO_2, the average price in the voluntary offset market (see Section 4.7 and Appendix B of EPRI 2011c for details of estimating methods).
- Aquatic biota: Impingement and entrainment = taxon- and region-specific values (provided in Appendix H of EPRI 2011c) calculated using the methods outlined by USEPA in its 316(b) Phase II and III regional benefits assessment:
  - Commercial fish species per pound WTP: $0.01 - $3.49
  - Recreational fish species per pound WTP: $0.98 – 12.76

– Forage fish species per pound WTP: \$0.01 – \$0.35

Available resources for the project allowed detailed evaluations of 24 facilities that were selected to represent the entire Phase II population of plants (39 nuclear and 389 fossil) (Appendix F of EPRI 2011c). Because three of these facilities have both nuclear and fossil-fueled units at the same generating station, they were considered one facility. Therefore, results that were calculated were based on 425 Phase II facilities.

Summary of Results

While a number of potential cooling tower impacts were only discussed in general terms due to a lack of quantitative data, eight were selected for more detailed analysis and wherever possible were quantified and monetized:

1. Human health
2. Terrestrial resources
3. Water resources
4. Solid waste
5. Public safety and security
6. Quality of life
7. Greenhouse gases
8. Permitting issues

In addition to the adverse impacts, the "Aquatic Biota" that would benefit from a closed-cycle retrofit was estimated for the 24 representative facilities. A summary of results is provided by topic in the following sections.

Human Health

Water 'drift' emissions are generated as a result of mechanical-draft evaporative cooling tower operation,. Drift consists of total dissolved solids (TDS) such as sodium, calcium, chloride, and sulfate ions contained in the water flowing through the cooling tower as well as organic matter (bacteria, spores, insect and vegetative material) that become entrained in the tower airflow through the force of the fans. There are two potential human health concerns associated with drift; fine particulates and pathogens.

Fine Particulates – Fine particulates are defined as particles 30 microns or smaller. Of particular concern to human respiratory health are particles (particulate matter or PM) that are less than 10 microns in diameter, referred to as PM_{10}. Emissions of PM_{10} are subject to environmental regulations intended to maintain or improve ambient air quality. USEPA also regulates particles that are less than 2.5 microns in diameter, or $PM_{2.5}$, and has developed and continues to refine regulations for particles of this size.

Mechanical-draft evaporative cooling towers in the study are assumed to use “drift eliminators” to limit the drift rate to 0.0005 percent of the circulating water flow rate and this figure was used in the modeling analysis. For the RFs modeled, fine particulates emitted ranged from 1.9 tons per year (TPY) (1.5 TPY PM_{10} and 0.6 TPY $PM_{2.5}$) to 877.8 TPY (352.5 tpy PM_{10} and 105.3 TPY $PM_{2.5}$). As expected, drift emissions were significantly greater for the higher salinity makeup water withdrawn from oceans, estuaries, and tidal rivers (i.e., average of 388.1 TPY/facility) compared to facilities withdrawing from freshwater (i.e., average of 17.1 TPY/facility). The population exposed to significant increases in PM_{10} and $PM_{2.5}$ ranged from 84 to 223,756 (Age 30+) and from 1 to 38,495 (Age 65+), respectively. Based on the analysis of the 24 RFs, it is estimated that 29,800 TPY of fine particulates (i.e., PM_{30}) would be generated. Of that amount there would be 13,500 TPY of PM_{10} (includes $PM_{2.5}$) and 4,200 tpy of $PM_{2.5}$ if all Phase II facilities were required to retrofit to mechanical-draft evaporative cooling towers.

Due to the lack of studies specifically related to the human health effects attributable to cooling tower generated fine particulates, the human health impacts are not reliably quantifiable. Any such impacts are likely to be extremely variable depending on the nature of the makeup water quality in the source waterbody. However, human health risk estimates based on USEPA methodology were also made for comparison (Appendix G of EPRI 2011c).

Pathogens – Another human health concern associated with cooling towers is the risk of disease caused by intake of aerosol sprays contaminated with *Legionella* sp. or other pathogens. The Cooling Technology Institute has developed best practices that include halogenation to minimize *Legionella* in cooling systems. The current state of the science does not allow for quantification of the potential risks caused by *Legionella* and other pathogens and, therefore, this potential impact was neither quantified nor monetized in the study.

Terrestrial Resources

Terrestrial resources include both natural resources and human-produced resources. Natural terrestrial resources are lands that serve as habitats for plant and animal species or are used for other purposes (e.g., agriculture). Human-produced resources include homes, cars, and a variety of other man-made objects. The construction and operation of cooling towers systems could result in the short-term or long-term loss of natural resources as well as impacts on human-produced resources. Temporary losses could be restored and long-term losses could be avoided to the extent practicable. The types of impacts studied included:

- Long-term loss of wildlife habitat, wetlands, and critical habitat;
- Salt and mineral drift effects on vegetation and soils;
- Noise impacts on terrestrial wildlife;
- Impacts of fogging and icing on terrestrial vegetation; and
- Salt and mineral drift impacts to man-made objects.

Long-term Loss of Wildlife Habitat, Wetlands, and Critical Habitat

Based on the information collected and analyses performed, the loss of critical habitat associated with a national closed-cycle cooling retrofit requirement may be summarized as follows:

- Four of the 24 plants studied, or 17 percent, estimated potential loss of critical habitat as a result of closed-cycle cooling retrofit
- Based on responses to the EPRI Questionnaire, 29 of the 209 facilities indicated terrestrial or wetland resources would be impacted by closed-cycle cooling retrofit. If the 7 facilities that reported wetland resources are subtracted, the remaining 22 facilities have impacts to unique, rare, or threatened habitats may be lost or up to 11 percent of the facilities surveyed.

Based on these two subsamples, between 47 and 72 of the Phase II facilities may experience potential loss of critical habitat as a result of closed-cycle cooling retrofit resulting in an average WTP estimate of approximately $17,000. Thus, the national annual WTP to avoid this loss may range from approximately $775,000 to over $1.19 million. This estimate is highly uncertain due to the site-specific nature of the impacts.

Salt and Mineral Drift Effects on Vegetation and Soils

Salt/mineral drift emitted from mechanical-draft evaporative cooling towers was evaluated in terms of potential effects on native vegetation, soils and crops. The study findings suggest that potential impacts to forests and non-agricultural herbaceous vegetation such as visible leaf damage were likely at most of the RFs investigated in this study, representing both saline and fresh water sites. However, since impacts were found to be highly site-specific depending on the type of vegetation, location of the vegetation relative to the tower location, and tower emissions, and due to the lack of information to estimate a WTP value, salt/mineral drift effects were neither scaled nor monetized.

Noise Impacts on Wildlife

Based on a literature review, a threshold of 60 decibels A-scale (dBA) represents the noise level above which wildlife potentially can be adversely affected. This noise level is used by the U.S. Fish & Wildlife Service in California for several species of birds including the least bell's vireo, California gnatcatcher and light-footed clapper rail. The acres of habitat exposed to a noise level greater than 60 dBA from cooling tower operation was estimated by modeling, and ranged from 111 to 208 acres for the seven Beta Test facilities. Nationally this impact could not be quantified nor monetized. However, there are potential impacts at some facilities, which were further discussed under permitting issues.

Impacts of Fogging and Icing on Terrestrial Vegetation

The Nuclear Regulatory Commission (NRC) has identified potential detrimental effects to the terrestrial environment from increased fogging and icing associated with cooling tower operation. These effects include increased humidity-induced fungal or other phytopathological infections on local vegetation, or ice damage. The NRC suggests an order-of-magnitude approach to the analysis of impacts of fog or ice related to cooling tower operation and this was the approach used in the current analysis.

Seasonal Annual Cooling Tower Impact (SACTI) modeling indicated that fogging at the rate of tens of hours/year is predicted to occur at eight of the 18 evaluated facilities (44.4 percent) and additionally, icing at this rate was predicted to occur at two of the facilities. Therefore, using the NRC guidelines, fogging and icing associated with cooling tower operation may cause detectable damage to vegetation, if present. At the national level, the current analysis was unable to monetize the WTP to avoid the damage due to site-specific variability in vegetation type (e.g., crops, critical habitat, and non-rare types) and lack of WTP data.

Human-Generated Terrestrial Resource Impacts

Salt deposition attributable to mechanical-draft evaporative cooling towers can damage automobiles and other metal surfaces, corrosion and shorting of electrical equipment, and spotting of windows and other surfaces. While in most cases, such impacts most likely occur within the facility property boundary, facilities using makeup water from oceans, estuaries and tidal rivers located in urban areas, may result in significant off-site property damage. Based on study results the critical rate of mineral deposition may occur at a distance up to 761 meters (2,500 feet) away from cooling towers for freshwater facilities and from 300 meters (980 feet) to more than 1,100 meters (3,600 feet) for facilities using saline or brackish water. These potential human-generated terrestrial resource impacts are not monetized due to a lack of economic data on which to base the WTP estimate and the lack of threshold effects data.

Water Resources

It is assumed that cooling tower discharges will meet applicable water quality standards. Using this assumption, three retrofit impacts were evaluated:

Evaporative Water Loss

Conversion to a closed-cycle cooling system will increase the evaporation rate compared to a once-through cooling system. Consumptive water loss from proposed closed-cycle cooling towers at modeled facilities is between ~400-900 gallons /MW-hr generated for fossil-fueled facilities and approximately 750-1,050 gallons/MW-hr for nuclear facilities, which is over double the water loss estimated for once-through cooling. As shown in Table 6-2, nationally, the total estimated freshwater evaporative loss is estimated to be 500 billion gallons/yr. Note that permitting and/or the issue of obtaining additional water rights to maintain water levels for cooling lakes and ponds in southwestern arid portions of the United States such as Texas and Oklahoma were not evaluated in the study.

Source Water Debris Removal

The majority of once-through condenser cooled facilities remove and dispose of material collected on their intake structure’s traveling screens or that accumulate in front of the intakes on trash racks. This includes natural material (logs, brush, leaves, sea weed, etc.) as well as man-made debris such as plastics, cans, paper, plastic can holders and other solid waste. Note that similar wastes are added to waterbodies via Combined Sewer Overflows, especially in large urban areas. The National Oceanic and Atmospheric Administration (NOAA) consider man-made debris as one of the most widespread pollution problems in the world's oceans, lakes and waterways. The reduction in the water volume withdrawn by closed-cycle cooling systems, and the associated reduction of man-made debris removed from the waterbody, was evaluated for characteristic facilities (Section 4.3.2 of EPRI 2011c). A national estimate of the amount of debris removed by the existing cooling water intake structures was made using responses to the EPRI Questionnaire and direct correspondence with some facilities. This total was 860 tons/yr.

The national-level WTP to avoid this consequence is shown in Table 6-4 and was estimated to be $974,100 ($382,900 for facilities on large freshwater rivers, lakes other than the Great Lakes and reservoirs, $273,300 for facilities withdrawing from small rivers and the Great Lakes and $317,900 for facilities located on oceans, estuaries and tidal rivers).

Solid Waste

Mechanical-draft evaporative cooling towers and natural draft cooling towers are constructed with water basins at the bottom of the towers. These basins contain cooling tower makeup water withdrawn from the source waterbody and collect the water that passes down through the cooling tower fill. Sediments settle out in the basin and must periodically be removed for disposal. Estimates of the amount of sediments potentially generated and other relevant information (e.g., potential toxicity) were investigated using a specific cooling tower solid waste EPRI questionnaire submitted to the industry (separate from the more general EPRI Questionnaire described above). A total of 47 facilities responded to the questionnaire.

Based on the results, the type of tower (mechanical-draft evaporative cooling towers versus natural draft cooling towers) does not appear to correlate with the amount of sediment accumulated. However, sediment generation at nuclear facilities is approximately 70 percent less than that at fossil plants (150 cubic yards per basin per year [CY/basin/year] compared to 500 CY/basin/year, respectively). Most facilities responding to the questionnaire that analyzed the sediment indicated that it was non-toxic, and that it was disposed of on-site or in public landfills with no additional permitting. Due to high variability in responses and lack of WTP data no attempt was made to quantify or monetize this waste.

Public Safety and Security

Water vapor emitted from mechanical-draft evaporative cooling towers may produce adverse social impacts in surrounding areas, such as:

- Fogging and icing of roadways;
- Fogging interference with nuclear facility security systems; and
- Visible plume interference with air traffic at nearby airports.

Public Safety of Roadways and Airports

Based on analysis of RFs, for the national scale-up, the WTP to avoid fogging impacts was estimated for the once-through cooled facilities by applying the median annual WTP to avoid fogging calculated from the RFs (Table 6-3) for high and medium/low population with and without major nearby roads. The Phase II facilities were grouped by population based on U.S. census data and proximity to roadways based on responses to the EPRI Questionnaire and best professional judgment using aerial photography. The national-level WTP to avoid impacts caused by fogging is estimated to be $54,700 (Table 6-4) ($7,300 for facilities on large freshwater rivers, lakes other than the Great Lakes and reservoirs, $29,800 for facilities withdrawing from small rivers and the Great Lakes, and $17,600 for facilities located on oceans, estuaries, and tidal rivers.

Roadway icing was a potential issue for 38.9 percent of modeled facilities suggesting up to 165 facilities may encounter some icing problems if cooling towers were operated. Based on the modeled impacts, icing may occur between 0.3 hours/year and 23.12 hours/year at these facilities. A WTP to avoid impacts from roadway icing could not be developed because appropriate accident data associated with these conditions are not available.

National scale impacts at airports of fogging associated with closed-cycle cooling were neither quantified nor monetized due to inadequate data, however, this could be an issue for any facility located in close proximity to an airport.

Security of Nuclear Facilities

The potential impact to the line of sight for maintaining security surveillance at nuclear facilities due to fogging is an additional concern posed by on-site cooling towers. Based on the results of the characteristic facilities modeling, the additional hours of fogging per year within the Protected Area ranged from negligible to 10 hours; 0.1 hours – 6 hours of additional fogging per year was estimated within the Owner Controlled Area. The WTP to avoid these potential security issues at the nuclear facilities could not be monetized because there are insufficient data. However, there are 39 Phase II facilities with at least one nuclear unit which may experience some negative impacts on security from cooling tower plumes.

Quality of Life

Cooling towers generate noise from pumps, fans, and falling water. In addition, there are impacts to the viewshed due to cooling tower size, height, and visible plumes. These impacts can affect adjacent or nearby communities in urban and suburban areas as well as cause impairments to recreational use in parks or other recreational areas.

Noise

- The impact associated with increased noise levels[10] from retrofitting to closed-cycle cooling is a function of the size of the tower, existing noise emissions sources on-site, the relative position of the cooling tower to these noise sources, off-site ambient noise, distance to and number of receptors (population), and topography.

Using the average annual WTP values calculated for the RFs in each geographic region, the annual WTP to avoid impacts associated with increased noise (two dbA or more) nationally at all once-through cooled facilities is estimated to be approximately $16 million ($7.4 million for facilities on freshwater LR/RL, $3.5 million for facilities on SR/GL and $5.3 million for facilities on O/E/TR (Table 6-4).

Viewshed

Viewshed deterioration is another quality of life issue associated with mechanical-draft evaporative cooling towers. The importance of this issue is generally related to the number of people who are exposed to the alternation in the viewshed as a result of the cooling tower size, height, and visible plume and the location of the tower relative to nearby seashores, parks or recreational areas. SACTI modeling was used to predict plume length and plume shadowing for the RFs. The estimated median WTP to avoid viewshed impacts is related to population size surrounding the facilities with the highest WTP in High population areas and much lower WTP in Medium/Low population areas ($15,400/facilty and $8/facility, respectively). Therefore, WTP to avoid viewshed impacts nationally was evaluated using the median annual WTP calculated for the RFs in two population groups (High and Medium/Low). See Appendix B (EPRI 2011c) for details of the methodology and Appendix E (EPRI 2011c) for a list of all Phase II facilities and their population category and source waterbody type. Using this approach, the results indicate that the national annual WTP to avoid potential viewshed degradation caused by the retrofit of all once-through cooling facilities is approximately $2.4 million, including $1.0 million estimated WTP for California facilities.

Greenhouse Gases

'Greenhouse gases' such as water vapor, carbon dioxide (CO_2), methane, nitrous oxide, and chlorofluorocarbons absorb and re-emit some of the Earth's outgoing thermal radiation and elevate the Earth's temperature. Increases in anthropogenic emissions of greenhouse gases have been implicated as promoters of 'climate change. Currently there is an international effort underway seeking to reduce greenhouse gas emissions. Thus, this impact represents the single exception to this study's focus on localized rather than regional impacts. This impact has been evaluated for nuclear facilities that would need to be taken off-line for closed-cycle system retrofitting. The larger question of retrofitting fossil-fueled plants and the impacts of converting these once-through cooled facilities on CO_2 emissions nation-wide has not been evaluated as part

[10] A sound level of zero dB is the approximate threshold of human hearing and is the reference level against which the amplitude of other sound is compared. A two dB increase in ambient noise levels is assumed to represent a quantifiable change in the acoustic environment.

of this study because of the uncertainties in plant closure and replacement. It has been estimated by U.S. Department of Energy that the energy penalty associated with wet cooling towers is:

- 2.4 to 4.0 percent for the hottest months of the year; and
- 0.8 to 1.5 percent for the annual average temperature conditions.

The national replacement of this power with the existing mix of generation would result in additional CO_2 emissions greater than those calculated for the nuclear plant retrofit.

If required to retrofit, nuclear facilities which are all baseloaded (i.e., capacity utilization in excess of 75 percent) are estimated, on average, to require an extended outage of six months to complete a retrofit. During the retrofit outage, it is assumed that the replacement electric power generation needed will come from existing fossil-fueled facilities. Due to uncertainty of outage duration, an 8-month outage time was also considered. Assuming a 6-month outage, it is estimated that 163 million tons of CO_2 would be generated for all once-through nuclear units with 74 million tons from facilities on LR/RL, 67 million tons from O/E/TR facilities and 22 million tons from facilities located on GL/SR (Table 6-2). Assuming an 8-month outage, it is estimated that 212 million tons of CO_2 would be generated for all once-through nuclear units with 99 million tons from facilities on LR/RL, 84 million tons from O/E/TR facilities and 29 million tons from facilities located on GL/SR (Table 6-2). The estimated WTP to avoid this impact based on carbon markets using an average price of $3.80 per ton of CO_2 in 2007$s are $13.0 million and $16.9 for 6- and 8-month outages, respectively, as shown in Table 6-4.

Permitting Issues

Due to the relatively large size of cooling towers and their potential environmental and social impacts, a variety of federal, state, and local permits may be required prior to construction. Potential permitting issues associated with closed-cycle cooling retrofits include, but are not limited to, air quality, environmental justice, threatened and endangered species, public heath, water quality, wetlands, consumptive water use, and other environmental issues. Such issues were evaluated for the 24 RFs and additionally through the questionnaire circulated to the industry through four major industry trade associations (Edison Electric Institute, Utility Water Act Group, National Rural Electric Cooperative and the American Public Power Association) in addition to EPRI members. The results of the 24 RF evaluations determined that for many power plants, at least one or more of the following topics are likely to be a concern:

- Air quality;
- Rare, threatened, and endangered species;
- Sensitive areas (e.g., wildlife management areas, refuges, critical dunes, etc.);
- Public health/water quality;
- Local ordinances and zoning (e.g., noise, night lighting, building height, etc.);
- Wetland disturbances; and
- Consumptive water use.

Additionally, nuclear plants will need to adhere to NRC requirements.

Air Permitting Issues

Permitting issues associated with air quality for many parts of the United States would likely be significant, based on the results of the in-depth evaluation of 14 RFs and the responses to the EPRI Questionnaire. The Prevention of Significant Deterioration (PSD) program would apply to cooling towers at 50 percent of the RFs assessed and 13 of the 14 RFs would require Title V Operation Permit modifications. Of the 209 responses to the EPRI Questionnaire, 40 percent of the facilities were located in a non-attainment area for air quality at the time of the questionnaire and 21 percent were located in or near a Class I area for air quality. Assuming these results are representative of all Phase II facilities, air quality permitting issues associated with a closed-cycle cooling retrofit may include:

- PSD program may apply at 213 facilities;
- Title V Operation Permit modifications may be needed at 395 facilities;
- 170 facilities may be located in a non-attainment area for air quality; and
- 90 facilities may be located in or near a Class I area for air quality.

Protected Species

Protected species and/or critical habitat affected by retrofits were identified for potential permitting issues for 58 percent of the RFs and wetlands were identified at two additional facilities. Over 50 percent of the EPRI Questionnaire responses indicated that threatened, endangered, or otherwise protected species are known to exist on site or in the vicinity of the facility. Additionally, 66 percent of EPRI Questionnaire facilities indicated that a sensitive receptor is located within 1 kilometer (3,280 feet) of the facility (e.g., landmarks, recreational areas, sensitive vegetation, protected species, new car lot, hospitals, and schools). This indicates that potentially 213-281 Phase II facilities may have permitting issues associated with protected species and/or critical habitat if they were to retrofit closed-cycle cooling.

Noise

An estimated, 54 percent of the facilities would likely have noise permitting issues based on the RF analysis while 44 percent (based on the EPRI Questionnaire) were located in areas with local noise ordinances. Results suggest that on a national scale between 187 and 230 Phase II facilities may have permit issues related to noise.

Building Height Ordinances

The RF analysis found two facilities were in areas with height ordinances while the questionnaire found approximately a quarter of the facilities reported height ordinances. It is estimated that between 35-107 facilities may need to meet permits for height.

Coastal Zone

Coastal zone regulations may require special permitting for three of the 24 RFs and over one-third of the EPRI Questionnaire respondents. It is estimated that between 53-140 facilities may require coastal zone permits.

Environmental Justice

Potential Environmental Justice issues (defined as potentially impacted areas with a minority population greater than 20 percent) exist for approximately 17 percent of the Phase II facilities, or 72 Phase II facilities based on the RF evaluation.

It is likely that most facilities that retrofit to closed-cycle cooling will encounter some permitting issues. This may result in significant additional costs to mitigate impacts and in some instances could potentially prevent the construction of cooling towers altogether.

Aquatic Biology

In contrast to the environmental and social impacts associated with closed-cycle cooling, there are two primary aquatic biological benefits. These are a reduction in cooling water intake structure impacts (impingement and entrainment) and a reduction in thermal impacts on organisms as a result of the thermal discharge. It was the initial intent of this study to include a comparison of the national closed-cycle cooling environmental and social impacts to the national benefits that would be achieved based on an assumed flow reduction of 93 percent or more that would be achieved with mechanical-draft evaporative cooling towers. However, preliminary analysis of the I&E data in the EPRI Impingement and Entrainment Database (EPRI 2011e) found a poor correlation between flow and either impingement or entrainment. As a result, EPRI initiated a separate study based on annual I&E estimated values using the impingement and entrainment database to develop an estimate of the national benefit of a retrofit requirement (see Chapter 7 and 2011d).

Thermal Plume Reduction Benefit

Use of once-through condenser cooling does result in a temperature rise in the cooling water that can exceed the thermal tolerance of some aquatic organisms, especially during warm summer periods in some parts of the United States. The USEPA water quality standards regulatory program has established thermal criteria for aquatic species that are used by regulators to set thermal limits for cooling water discharge. Most generating facilities comply with those standards. However, the CWA at §316(a) provides a variance provision from the thermal criteria. Under this provision, facilities can apply for a thermal variance by demonstrating the protection and propagation of a balanced, indigenous community of fish and wildlife in and on the waterbody into which the discharge is made. Relative to the thermal discharge, this report assumes that once-through cooled facilities either comply with thermal mixing zone standards or have completed a CWA §316(a) Demonstration.

Impingement and Entrainment

By reducing condenser cooling water flow, the use of mechanical-draft evaporative cooling towers will result in a significant reduction in both impingement and entrainment for most facilities. Potential reductions were calculated for the 24 RFs and two additional facilities to augment the O/E/TR category that was considered underrepresented because of the large number of facilities in the category and diversity of aquatic populations in these types of waterbodies.

The quantified results are provided in Table 6-5 of EPRI 2011c. For facilities located on waterbodies with commercial fisheries, losses ranged from 30 lbs/yr to 620,100 lbs/yr. Recreational fishing losses existed at all 26 facilities and ranged from 40 lbs/yr to 284,000 lbs/yr. Foregone forage fish losses (i.e., non-commercial and non-recreational fish that may be a food source for commercial and recreational species) ranged from 6 lbs/yr to just under 3.6 million lbs/yr. The WTP monetized losses for the 24 representative facilities are provided in Table 6-3 and ranged from $100/yr to $568,500/yr. However, it is important to note that approximately half of the RFs did not conduct entrainment studies and therefore these losses were neither quantified nor monetized.

Based on the study of environmental and social impacts of closed-cycle cooling retrofits should they be designated as BTA, a number of conclusions can be drawn relative to those potential impacts:

- The quantified and monetized environmental and social impacts of closed-cycle cooling tend to be site-specific and are a function of the waterbody type, adjacent land use, fuel type, and nearby human population density.
- Potential human health, terrestrial, social, noise, viewshed degradation, and safety impacts are dominant in urban and suburban areas while terrestrial ecological and agricultural impacts are dominant in rural or undeveloped areas.
- Giving no consideration to greenhouse gas emissions and human health effects, the net monetized closed-cycle cooling environmental and social impacts exceed the monetized benefits for just less than half the RFs. If monetized greenhouse gas impacts are included, only six of the 24 RFs had monetized benefits that exceeded monetized impacts of closed-cycle cooling.

Considerable uncertainty remains for both monetized impacts and benefits and methods are currently unavailable for monetization of some benefits as well as a number of impacts associated with closed-cycle cooling.

Table 6-1
List of Impacts Considered and Either Quantified, Monetized and/or Narratively Discussed in the Closed-cycle Cooling Retrofit Study

Category	Quantified	Monetized	Narrative
Human Health			
Legionnaire's Disease			X
Exposure to Increased PM	X		X
Mortality and Morbidity from PM Exposure	X	X	X
Terrestrial Resources			
Long-term Loss of Non-unique, Non-rare Habitats	X		X
Long-term Loss of Unique, Rare Habitat	X	X	X
Salt/ Mineral Drift Impact to Native Vegetation	X		X
Salt / Mineral Drift Impact to Agricultural Soil	X	X	X
Noise Impact to Terrestrial Wildlife	X		X
Fogging/Icing Impacts on Terrestrial Vegetation	X		X
Bird, Bat, and Insect Collisions/ Entrainment into Cooling Tower			X
Salt Damage to Off-site Property	X		X
Water Resources			
Evaporative Water Loss (Potable Water)	X		X
Biocides and Trace Metal Discharge			X
Solid Waste			
Debris Removal	X	X	X
Solid Waste Generated by Cooling Tower			X
Public Safety / Security			
Icing of Roadways	X		X
Fogging of Roadways	X	X	X
Fogging/Icing at Airports	X		X
Fogging at Nuclear Facilities	X		X
Quality of Life			
Noise	X	X	X
Viewshed	X	X	X
Greenhouse Gas			
6- and 8-Month Outages at Nuclear Facilities	X	X	X
Additional CO_2 Associated with Energy Penalty			X
Change in Composition of Generating Fleet			X
Water Vapor as Greenhouse Gas	X		X
Aquatic Biota			
Impingement and Entrainment of Fish and Shellfish	X	X	X
Entrainment of Planktonic Organisms			X
Thermal Discharge Effects			X
Other			
Cumulative Impacts			X

Table 6-2
National Estimate of Quantified Environmental Impacts Should Closed-cycle Cooling be Designated as Best Technology Available

Impact Type	Large Freshwater Rivers, Freshwater Lakes (non-Great Lakes) and Freshwater Reservoirs	Great Lakes and Small Rivers	Oceans Estuaries and Tidal Rivers	Total Quantity
Human Health				
PM (tons/year)	2,000	800	27,100	29,800
PM_{10} (tons/year)	1,400	600	11,500	13,500
$PM_{2.5}$ (tons/year)	600	200	3,400	4,200
Exposed Population (Age 30+)	1,003,500	6,063,700	8,977,900	16,045,000
Exposed Population (Age 65+)	226,300	1,098,000	1,641,700	2,966,000
Terrestrial Resources				
Noise impacts on wildlife (# facilities)	96	39	22	157
Fogging/icing impacts on vegetation (# facilities)	115	59	0	174
Water Resources				
Active chlorine use (metric tons/year)	18,000	7,000		25,000
Evaporative water loss (billion gallons/year)	372	128	NA	500
Debris removal (tons of trash not removed/year)	338	241	281	861
Greenhouse Gas				
CO_2 Emitted (million tons) 6-month outage	74	22	67	163
CO_2 Emitted (million tons) 8-month outage	99	29	84	212

Table 6-3
Comparison of Monetized Environmental and Social Impacts with the Benefits associated with a reduction in IM&E for 24 Representative Facilities

Representative Facility	Increased Man-Made Debris	Public Safety/ Increased Roadway Fogging [c]	Increased Noise [c]	Viewshed Degradation [a, c]	Decreased IM and E [d]	Net Annual Average WTP to Avoid Change to Closed-cycle Cooling [b,e]	Increased Greenhouse Gases [f]	Net WTP to Avoid Change to Closed-cycle Cooling [e]
BTCA1[(1)]	$18,600	<$50	$53,800	$189,300	($133,000)	$128,700	--	$128,700
BTPA	N/A	$0	$0	$300	($40,600)	($40,300)	--	($40,300)
BTPB[(2)]	$11,100	$100	$5,800	$8,600	($65,200)	$71,200	$428,800	$500,000
BTPC	$2,200	<$50	$0	$4,400	($241,700)	($235,100)	--	($235,100)
BTPD	$0	<$50	$16,200	$1,700	($400)	$17,500	--	$17,500
BTPE[(3)]	N/A	$0	$1,600	$100	($6,300)	($4,500)	$493,800	$489,300
BTCA2	$0	$2,800	$0	$157,800	($408,900)	($248,300)	$438,400	$190,100
RFF	$200	<$50	$0	$0	($569,800)	($569,600)	--	($569,600)
RFG	N/A	$200	$11,100	<$50	($6,200)	$5,100	--	$5,100
RFH	$0	$0	$19,600	$4,900	($47,400)	($22,900)	$411,200	$388,300
RFI	$46,600	$23,500	$0	$27,600	($8,100)	$89,600	--	$89,600
RFJ	<$50	<$50	$63,000	$0	($1,100)	$61,900	--	$61,900
RFK	$0	<$50	$0	$3,200	($91,900)	($88,700)	--	($88,700)
RFL	N/A	$400	$245,900	$0	($1,600)	$244,700	--	$244,700
RFM	$3,000	$0	$186,900	$0	($5,100)	$184,800	--	$184,800
RFN	N/A	$100	$73,900	$0	($500)	$73,500	--	$73,500
RFO	$0	$100	$0	<$50	($5,400)	($5,300)	--	($5,300)
RFP	N/A	$0	$14,700	<$50	($1,800)	$12,900	--	$12,900
RFQ	$45,600	<$50	$0	$0	($400)	$45,200	--	$45,200
RFR	$0	N/A	$0	<$50	($100)	($100)	--	($100)
RFS	$1,500	$100	$0	$1,000	($40,200)	($37,600)	$334,800	$297,200
RFT	$300	$0	$29,400	$0	($13,000)	$16,700	--	$16,700
RFU	$200	<$50	$0	$0	($200)	<$50	--	<$50
RFV	$400	<$50	$800	$100	($800)	$500	$214,300	$214,800

Notes, Table 6-3:

1. Does not include $5,200 to off-site wetland.
2. Includes $110,800 for increased terrestrial habitat impacts.
3. Includes $80 for increased salt deposition.

a. Visual impacts include housing <u>and recreational</u> impacts.
b. Net willingness to pay without including human health or greenhouse gas emissions.
c. Impacts for these issues at RFM, RFN, RFO, RFP, RFQ, RFR, RFS, RFT, RFU, RFV were based on impacts for similar facilities; they were not modeled.
d. These values indicate the WTP to avoid IM&E-related losses, not the total monetized losses due to IM&E.
e. Note totals may not equal due to rounding.
f. Assumes a 6-month shutdown.

Table 6-4
Monetized Impacts Should Closed-cycle Cooling be Designated as Best Technology Available of for Various Waterbody Types

Type of Impact	Annual WTP to Avoid Impacts (2007$)	
Water Resources – Debris Removal		
Freshwater Large Rivers, Reservoirs and Lakes	$382,900	
Small Rivers and Great Lakes	$273,300	
Oceans Estuaries and Tidal Rivers	$317,900	
Sub-total	$974,100	
Public Safety – Roadway Fogging		
Freshwater Large Rivers, Reservoirs and Lakes	$7,300	
Small Rivers and Great Lakes	$29,800	
Oceans Estuaries and Tidal Rivers	$17,600	
Sub-total	$54,700	
Quality of Life – Noise		
Freshwater Large Rivers, Reservoirs and Lakes	$7,350,400	
Small Rivers and Great Lakes	$3,468,400	
Oceans Estuaries and Tidal Rivers	$5,322,800	
Sub-total	$16,141,600	
Quality of Life - Degraded Viewshed		
Freshwater Large Rivers, Reservoirs and Lakes	$281,100	
Small Rivers and Great Lakes	$373,600	
Oceans Estuaries and Tidal Rivers	$1,702,200	
Sub-total	$2,356,900	
Greenhouse Gas		
	6-Month Outage	8-Month Outage
Freshwater Large Rivers, Reservoirs and Lakes	$5,918,900	$7,891,900
Small Rivers and Great Lakes	$1,740,900	$2,321,200
Oceans Estuaries and Tidal Rivers	$5,359,000	$6,683,400
Sub-total	$13,018,800	$16,896,500
Cumulative Monetized Impacts [a]		
Freshwater Large Rivers, Reservoirs and Lakes	$13,940,600	
Small Rivers and Great Lakes	$5,886,000	
Oceans Estuaries and Tidal Rivers	$12,719,500	
Total Monetized Impact Estimate	$32,546,100	

Totals may not equal due to rounding.
[a] Assumes a 6-month outage for nuclear facilities

7
POTENTIAL ENVIRONMENTAL BENEFITS ASSOCIATED WITH CLOSED-CYCLE COOLING

The methodology and results of EPRI's study to estimate the potential benefits associated with closed-cycle cooling are provided in: National Benefits of a Closed-cycle Cooling Retrofit Requirement (EPRI 2011d).

Study Approach

To develop the national benefit estimates, the analysis used as much existing site-specific information as possible regarding both I&E rates and the benefits of reductions. This analysis assumed there are 426 electricity generating facilities subject to the Phase II Rule. Many of these collected impingement and entrainment (I&E) data as part of compliance with the remanded rule. EPRI developed a database of the I&E data collected by these facilities (EPRI 2011e). This data collection resulted in impingement data for 230 facilities and entrainment data for 113 facilities. In addition to developing a national I&E database, EPRI collected site-specific benefit estimates from individual facilities that had calculated the benefits of I&E reductions at their sites. These exist because the remanded rule allowed use of a cost-benefit test in making site-specific BTA determinations. However, conducting site-specific benefit valuation studies for every facility with I&E data was not feasible for the current analysis. To overcome this, EPRI developed a statistical model of the relationship between I&E reductions and benefits. Before conducting the statistical evaluation, EPRI evaluated the set of available benefit valuation studies by categorizing facilities into 17 groups (strata) based on waterbody types and regions of the U.S. These strata represent regions where the statistical power of the modeling approach was assessed. Based on the relationship between the existing benefit studies and these strata, EPRI identified strata where additional site-specific benefit valuation studies were needed to provide greater statistical power for identifying the relationship between I&E reductions and benefits. As a result of this assessment, EPRI developed benefit valuation studies for an additional 22 facilities across these 17 strata.

The development of the national benefit estimate relied on the combination of existing and newly conducted benefits studies. These studies were conducted using a variety of methods. One common similarity relates to the biological information used to calculate impacts. Without exception, the studies rely on sample counts of impingement and entrainment. These sample counts are weighted up by flow to create an estimate of total impingement and entrainment for that facility for the sampled year. All studies use these annual impact estimates to identify fishery impacts. The majority of the studies employ an Equivalent Loss approach (EPRI 2004) in which the annual estimates of I&E of forage fish species are converted to a lesser numbers of adults via successive multiplication that considers survival at each life stage.[11] A much smaller number of the studies employed a dynamic approach that incorporates the reproductive process of the impinged and entrained species. None of the studies modeled compensatory effects.[12]

These methods result in fishery yield impacts. All of the studies convert these estimates of lost fishery yield into estimates of economic impacts on commercial and recreational fisheries. For commercial benefits, a number of approaches are employed. All approaches consider the value of the increased yield in terms of per pound values by species. Various specifications of price responsiveness to quantity changes are employed to identify whether benefits arise primarily for fish consumers or commercial fishers. For recreational benefits, two general approaches are employed. One is similar to EPA's 2004 national benefits study[13]. In this approach, yield change estimates are converted into changes in expected catch. Economic benefits are identified as the difference in consumer surplus when catch rates are specified and demand curves simulated under Baseline and With Closed-Cycle Regulation conditions. In the other approach, yield changes are converted directly into dollar values via multiplication by species and region-specific, per-fish values. This is the approach taken by EPA in *Economic and Benefits Analysis for the Final Section 316(b) Phase III Existing Facilities Rule* (EPA 2006).

The methods for converting the facility-level estimates into the national benefit estimates are based on using the best information available to formulate separate impingement and entrainment benefit estimates for each facility. Each power station falls into one of three tiers or levels of available information. Tier 1 facilities have site-specific benefit estimates based on quantitative I&E studies that are computed for the specific species composition observed for each facility. Facilities in Tier 2 have quantitative I&E data, but this information has not been used to estimate a site-specific benefit estimate. Tier 2 is considered the second-best level of information. The remaining facilities form Tier 3 and have neither a plant-specific benefit estimate nor quantitative I&E data.

For facilities in Tier 1, the calculated benefit estimate is accepted as the best available information. For facilities in Tiers 2 and 3, model-based estimates of benefits were calculated. Using the existing I&E data, benefit valuation studies for the 70 facilities, and the 22 additional site-specific benefit valuation studies, EPRI developed a statistical model to evaluate the relationship between I&E reductions and benefits. The results of the statistical model were used to predict benefit estimates for the remaining 127 Tier 2 plants with impingement data and the 45 facilities with entrainment data. For the 196 Tier 3 plants with neither impingement data nor benefit estimates and 313 plants with neither entrainment data nor benefit estimates, a statistical model of the relationship between plant design flow and benefits was developed and used to predict the benefits based on the 196 and 313 plants' design flow. Thus, the national benefit estimate is the sum of the existing benefit valuation studies, the site-specific benefit valuation

[11]This approach is similar to the approach taken by EPA in its analyses if I&E impacts (cite those).

[12] Modeling compensatory effects requires identifying and specifying the complex relationships between survival rates as affected by population sizes.

[13] U.S. Environmental Protection Agency. 2004c. *Regional analysis document for the final Section 316(b) existing facilities rule*. EPA-821-R-02-003. February 12. U.S. EPA Office of Water, Washington, DC.

studies, the estimated benefits for facilities with I&E data, and the estimated benefits for facilities without I&E data.

Study Results

The results of the analysis estimate that the annual benefits associated with the I&E reductions resulting from a national closed-cycle cooling retrofit requirement would be approximately $16 million annually with a lower bound estimate of $13.8 million/year and an upper bound estimate of $22.7 million/year. Based on this annual benefit estimate range, the corresponding present value over 30 years at a 3% discount rate is $270.5 million, $313.5 million, and $444.9 million with annualized (present value divided by 30) values of $9.02, $10.45, and $14.83 for the lower, midpoint, and upper values. Although methods employed to calculate recreational and commercial benefits are similar, this estimate is quite a bit lower than the over $120 million dollar estimate presented by EPA in Exhibit VIII-10. The EPA number is higher because it includes nonuse benefits and benefits from impacts to threatened and endangered species. Also, EPA benefit numbers include I&E reductions at industrial and manufacturing facilities. The EPRI estimates include only power generating facilities. In addition, EPA estimates are based on a largely different entrainment and impingement monitoring dataset, much of which appears to be 20 or more years old. Finally, EPA estimates were developed using natural mortality rates that were unadjusted to a stable age distribution. Such unadjusted mortality rates could lead to substantial overestimates of economic value owing to the use of unrealistically high rates of population growth.

Table 7-1
Regional Estimates of I&E Reduction Benefits

Region	Sample Size	Impingement Benefits	Entrainment Benefits	Total Benefits
Lake Erie	13	$1,953,403	$516,701	$2,470,103
Lake Huron	5	$15,657	$15,712	$31,370
Lake Michigan	17	$212,830	$166,175	$379,005
Lake Ontario	6	$57,555	$29,328	$86,883
Lake Superior	6	$6,046	$5,238	$11,284
Central River	154	$1,244,202	$1,641,066	$2,885,269
Eastern River	33	$53,982	$159,757	$213,739
Western River	1	$144	$71	$216
Mid-Atlantic Coastal	24	$1,597,821	$1,988,619	$3,586,440
Northeastern Coastal	32	$84,072	$708,581	$792,653
Pacific Ocean	18	$358,494	$1,590,220	$1,948,714
Southeastern Coastal	11	$68,547	$737,801	$806,348
Southern Coastal and Gulf	18	$346,155	$525,338	$871,494
Midwestern Reservoirs	22	$83,405	$102,908	$186,313
Southeastern Reservoirs	22	$65,386	$681,915	$747,301
Southwestern Cooling Lakes	34	$127,761	$661,571	$789,333
Special Case	10	$90,543	$128,201	$218,744
Total	426	$6,366,005	$9,659,202	$16,025,207

Quantifying economic benefits in this context is complex, resulting in a number of uncertainties in the precision of benefit estimates. With respect to uncertainty in aggregation, the numbers of facilities in each tier differ for impingement and entrainment because both impingement and entrainment count data were not always available at each facility. For impingement estimates, 93 facilities (22%) fall into Tier 1, 137 facilities (32%) fall into Tier 2, and 196 facilities (46%) fall into Tier 3. For entrainment estimates 68 facilities (16%) fall into tier 1, 45 facilities (11%) fall into Tier 2, and 313 facilities (73%) fall into Tier 3. Because of the larger proportion of facilities in Tier 3 which uses the least certain estimation model, we expect greater uncertainty for the entrainment estimates. In the final estimates, the upper bound for entrainment exceeds the estimate by a factor of 1.63 and the upper bound for impingement exceeds the estimate by a factor of 1.38.

In making an estimate of the national benefits from fish and aquatic life should closed-cycle cooling be designated as BTA, it is important to consider the uncertainties and assumptions associated with the estimates. Assumptions and uncertainties are grouped into three categories:

1. those likely to underestimate the benefits of closed-cycle cooling
2. those likely to overestimate the benefits of closed-cycle cooling and
3. those that could result in either overestimating or underestimating benefits

Assumptions/uncertainties likely to underestimate closed-cycle cooling retrofit benefits

a) Nonuse benefits—Nonuse benefits result from the values that people may hold for a resource independent of its use. For example, a threatened or endangered species cannot be used but people derive value from knowing the resource exists either for future generations or because it has an inherent right to exist. EPRI has not included estimates of nonuse benefits because there are currently no generally accepted methods to develop valid estimates with a reliable level of precision. EPRI is aware that EPA has proposed a study using survey methods to quantify these values, and EPRI has provided comments on the approach as well as summary of the methodology in Chapter 4 of EPRI 2011d.

b) Cooling water thermal impacts – Heat rejected from once-through systems to adjacent waters can be an additional source of adverse ecological effects. Water quality standards impose limits on the thermal effluent discharged to waters of the U.S. to protect aquatic communities and ecosystems. Section 316(a) of the Clean Water Act provides a unique variance provision due to the temporary physical nature of heat as a pollutant by demonstrating that the thermal discharge would ensure a balanced population of fish and aquatic life in and on the waterbody. Use of closed-cycle cooling is considered Best Available Technology (BAT) for thermal discharges and could provide the benefit of eliminating any remaining adverse effects to fish and other aquatic organisms as a result of reduced thermal effluent. However, this benefit would be offset by a reduction in seasonal recreational fishing that occurs in the thermal discharge area and other water quality benefits that occur at some facilities as discussed under (g) below.

c) Lack of consideration to lower trophic levels—In addition to significantly reducing impingement and entrainment losses, closed-cycle cooling would also provide potential benefits to lower trophic level organisms such as zooplankton and phytoplankton as well as macrophytes that may be affected by cooling water discharge sediments or exposure to the thermal plume. EPA considered impacts to zooplankton and phytoplankton in the Phase II Rule and determined there was a lower risk to such species due to their relatively short generation time (i.e., days or weeks compared to months or years for fish and shellfish). The result of not including such losses in the benefit estimate is believed to result in a small underestimate of the benefits.

Assumptions/uncertainties likely to yield an overestimate of closed-cycle cooling retrofit benefits

a) Reduced form recreational model—Many of the site-specific studies used to calculate what recreational anglers are willing to pay for increased catch rates assume that anglers experience the same increase in satisfaction for each additional fish caught (also assumed by EPA). Thus the angler is 10 times as happy catching her 10th fish and is willing to pay the same amount to catch her tenth fish as she was to catch her first with a similar proportional increase in the economic benefit. While there is general consensus that higher catch rates increase trip values, that value does not necessarily increase proportionally with catch rates, but rather diminishes as catch increases. That is, anglers are more likely to be willing to pay more to catch their first fish than their tenth fish. The result is that the assumption of increasing proportional value overestimates the economic benefit.

b) Impingement and entrainment mortality—EPRI's study assumed 100% mortality for all impinged and entrained organisms. However, for many facilities impingement and entrainment survival can be significant depending on the species, through facility transit time, biocide use, heat load and fish return system. To the extent that survival exists at any individual facility, the economic benefits of cooling towers will be overestimated.

c) Density dependence—This refers to the ability of populations of fish and other aquatic organisms to compensate for losses such as commercial and recreational harvest or I&E. Fish species reproduce by generating large numbers of eggs with the expectation that only a few will survive. Loss of individuals as a result of harvesting or I&E creates more food and habitat for the remaining fish, which results in faster growth and survival for those individuals; however, compensatory response varies with population fluctuations and technically sound methods to accurately quantify this phenomenon remain elusive. EPRI has assumed no compensation in the analysis which results in an overestimate of the benefit of an undetermined amount.

d) Impinged and entrained organism health—With the exception of excluding some gizzard shad at some facilities due to winter cold shock, the benefit analysis assumed all impinged and entrained organisms are alive and healthy at the time of interaction with the cooling water intake structure. However, research by EPRI and others suggests that for at least some facilities and species, the health of impinged and/or entrained organisms may be impaired or they may be dead on arrival at the intake. Not fully accounting for fish that are dead on arrival or that are in poor health and not likely to survive regardless of I&E results in an overestimate of the benefit.

e) Predator prey modeling—Both EPRI and EPA assume that increased numbers of non-harvested forage species (e.g., gizzard shad, bay anchovies, and gobies) resulting from closed-cycle cooling will all be consumed by commercially or recreationally harvested species. In reality, much of the increased biomass assumed to be generated by non-harvested forage species could be consumed by zooplankton, jellyfish, or non-harvested species of finfish. Thus, the assumption that all forage biomass resulting from closed-cycle cooling retrofits is consumed by harvested species overestimates the economic benefit by an undetermined amount.

f) Nuisance and exotic species—Exotic species are non-native species that have been introduced into a waterbody (accidentally or intentionally for recreational or commercial purposes). They may be viewed as a problem due to their displacement of native species or disproportionately high abundance. While they may have recreational value in some cases, in many cases resource managers may institute fishery management polices to extirpate such species and spend economic resources to achieve that goal (e.g., efforts to extirpate sea lamprey from the Great Lakes). This results in the case that losses of such species could be viewed as a benefit. In this study, EPRI made the assumption that increases in such species, as a result of closed-cycle cooling, would be treated as forage species and would be consumed by harvested species. This conservative assumption overestimates the economic benefit estimate by failing to account for the benefits of impingement and entrainment losses for such species in some waterbodies.

g) Water quality flow and habitat for some facilities—At some facilities, once-through cooling water flow provides water quality benefits and seasonal recreational fishing benefits that would be eliminated if these facilities were to retrofit with closed-cycle cooling. Examples include providing water circulation to increase productivity in otherwise stagnant waterbodies, providing opportunities for recreational fishing in thermal discharges during colder months providing a refuge during these periods for species subject to coldwater induced mortality, and providing habitat for manatees. This study did not attempt to quantify such benefits and failure to account for the lost benefits results in an overestimate of the benefits of closed-cycle cooling retrofits.

h) Remaining facility life—The national study assumes all 426 facilities would retrofit with closed-cycle cooling and reduce flow by 93%. Also, site-specific studies employed in the evaluation typically assumed that cooling towers would produce benefits for 30 years. However, as discussed in EPRI's study on the financial and economic impacts of closed-cycle cooling as BTA (EPRI 2011a) some facilities would be prematurely retired for economic reasons rather than retrofit with closed-cycle cooling. Additional facilities may simply have scheduled retirement prior to the assumed 2016 retrofit date. The result would be that once the facility closes there would no longer be a benefit accrued by the closed-cycle cooling system. the result is an overestimate of national benefits.

Assumptions/uncertainties that could result in either an underestimate or overestimate benefits

a) Reduced form commercial benefit models—Similar to the issue of reduced form recreational fishing models, simplifying assumptions are made such that as commercial harvest increases, there is a corresponding increase in the value of the commercial harvest. However, in reality, commercial fishing markets are complex and as harvest increases there may be a decrease in the dockside market price as a result of competition. Fully accounting for market complexity in site-specific assessments could result in either over or underestimating benefits.

b) Field sampling uncertainties—The I&E estimates used in this study were typically made by extrapolating sampling densities (number per unit volume) representing a relatively small cooling water volume over an expanded cooling water volume used by the power station to obtain estimates over longer time frames (e.g., monthly or annual). This is especially true for entrainment due to the relatively small volume sampled compared to overall cooling water flow and the patchiness of larval densities in that flow. For impingement, incidents can occur where most of the annual impingement can occur over a relatively short period of hours or days. EPRI has issued prior reports detailing these issues and for the purpose of this study assumed I&E studies provided followed standard protocols, used acceptable QA/QC procedures and are representative of annual levels of I&E. However, due to issues associated with episodic events and timing and variability for some species there are uncertainties that could result in either over or underestimating I&E losses.

c) Annual variability—Populations of fish and shellfish can vary significantly from year to year. Over time, shifts in dominant species can occur in addition to population shifts due to accidental or intentional introductions of non-native or exotic species. Based on an analysis conducted in this study, such annual variation in species can be as high as four orders of magnitude. For most of the facilities used in this analysis, economic estimates were based on a single year of study. The result is that economic estimates for individual facilities could represent overestimates or underestimates compared to average years and the average may shift over time.

d) Changes in the state of fisheries—The economic estimates provided in this report reflect values based on the current state of these fisheries. However, fisheries undergo continuous flux that includes imposition and lifting of fishing bans for various species in addition to catch limits. These changes in fisheries directly affect commercial and recreational values. The result is that such changes could result in significant changes in economic values that could result in current estimates being either lower or higher than what might occur in the future.

e) Uncertainty in the identification of impinged and entrained organisms—In order to estimate the economic benefits of I&E reductions as accurately as possible it is necessary to identify these organisms at the species level. Generally, it is possible to identify impinged organisms to species; however, this is not the case for all early life stages as a result of 1) species not sufficiently studied to allow accurate species level identification, 2) there is inadequate morphological development to differentiate closely related species or insufficient differentiation of fish eggs for accurate identification and 3) some specimens may be damaged either as a result of entrainment or collection in entrainment samples. These can be a particular problems at some facilities and best professional judgment must be used to estimate species losses. Depending on the species for which incorrect taxonomic identifications occur, economic benefits could be either over or underestimated.

f) Lack of current entrainment data for some waterbodies—The I&E studies used in this analysis were conducted in anticipation for compliance with the now remanded Phase II Rule. That Rule exempted facilities located on freshwater reservoirs and lakes (other than the Great Lakes) and freshwater rivers for facilities that used less than 5% of the mean annual flow from having to comply with the entrainment reduction performance standard. The result being that a large number of facilities located on these waterbody types did not conduct entrainment studies. The statistical modeling techniques applied to develop benefit estimates for these facilities lead to economic benefits that could be either over or under estimated for these facilities.

g) Relationship of flow to I&E—The issues here are separate for I&E. In terms of impingement, EPRI studies have not found a strong relationship between flow and impingement. However, it has been noted that in many cases facilities with closed-cycle cooling generally tend to have lower intake velocities and there is a direct relationship between impingement and velocity. The result for the purpose of this study is that by not accounting for this additional benefit there is a small increase in benefits not accounted for in the analysis. In terms of entrainment, it is important to note that as entrainable life stages grow, some species develop behavioral mechanisms that allow them to avoid entrainment and for such species, assuming that entrainment is proportional to flow would result in an overestimate of entrainment benefits. Two examples for the Chalk Point Station on the Chesapeake Bay include bay anchovies, where it was found that small larvae stayed on the bottom of the estuary during the day and were not entrained in significant numbers and for naked gobies, the larvae at approximately 12 mm in length exhibited a strong ability to avoid entrainment. Models used prior to this information becoming available, based on flow proportionality, significantly over predicted entrainment losses. In summary, while there is some small underestimate of benefits for impingeable sized organisms, there is an unspecified overestimate of benefits for entrainable life stages.

Overall, EPRI identified three assumptions and uncertainties that potentially underestimate the benefit of closed-cycle cooling, eight factors that could potentially overestimate the benefit, and seven factors that could result in either underestimating or overestimating the benefits. The significance of these uncertainties varies in terms of the potential magnitude on the overall estimate of benefits. At this time it is not possible to estimate the overall net effect on the estimate. However, EPRI did address the following factors quantitatively using sensitivity and a Monte Carlo analysis:

- Natural mortality rate
- Fishing mortality rate
- Fraction commercial fishery
- Vulnerability to fishery
- Mean weight at beginning of each stage
- Trophic conversion factor
- Exploitation rate for equivalent predator
- Commercial price per pound
- Producer surplus
- Recreational value per pound.

Of these factors, the uncertainty in natural mortality rates and recreational values per pound contribute to the largest quantified uncertainty in benefits.

Factor	Range (percent)
Natural mortality rate	-36.9 - 189.0
Fishing mortality rate	-7.3 - 5.3
Fraction commercial fishery	-3.5 - 3.5
Vulnerability to fishery	-3.3 - 2.2
Mean weight at beginning of each stage	-20.3 - 20.1
Trophic conversion factor	-15.6 - 15.6
Exploitation rate for equivalent predator	-12.5 - 12.5
Commercial price per pound	-0.9 - 0.9
Producer surplus	-0.8 - 0.8
Recreational value per pound	-55.1 - 161.0

While closed-cycle cooling does provide a significant benefit in terms of reducing I&E mortality, the technology itself results in a variety of potential environmental and social impacts that vary in significance depending on the location of the facility and placement of the cooling tower on the site as discussed in Chapter 6 of this report and in more detail in EPRI (2011c).

8 REFERENCES

1. Electric Power Research Institute. 2010. Closed-cycle retrofit study: capital and performance cost estimates. EPRI, Palo Alto, CA. (EPRI 1022491)
2. Electric Power Research Institute. 2004. Extrapolating Impingement and Entrainment Losses to Equivalent Adults and Production Foregone. EPRI, Palo Alto, CA. (EPRI 1018471)
3. Electric Power Research Institute. 2011a. Evaluation of the national financial and economic impacts of a closed-cycle cooling retrofit requirement. EPRI, Palo Alto, CA. (EPRI 1022751)
4. Electric Power Research Institute. 2011b. Maintaining electrical system reliability under a closed-cycle cooling retrofit requirement. EPRI, Palo Alto, CA. (EPRI 1023174)
5. Electric Power Research Institute. 2011c. Net Environmental and Social Effects of Retrofitting Power Plants with Once-through Cooling to Closed-cycle Cooling. (EPRI 1022760)
6. Electric Power Research Institute. 2011d. National Benefits of a Closed-cycle Cooling Retrofit Requirement. (EPRI 1023401)
7. Electric Power Research Institute. 2011e. National and Regional Summary of Impingement and Entrainment of Fish and Shellfish Based on an Industry Survey of Clean Water Act §316(b) Characterization Studies. (EPRI 1019861)
8. North American Electric Reliability Corporation. 2011. "Testimony of Gerry Cauley, NERC President and CEO" before the One Hundred Twelfth Congress of the United States, House of Representatives, Committee on Energy and Commerce, Subcommittee on Energy and Power, April 7, 2011. Available at http://www.nerc.com/fileUploads/File/News/HECC_Cauley07APR11.pdf. Retrieved on May 24, 2011.
9. USEPA (Environmental Protection Agency). 2004. Final Regulations to Establish Requirements for Cooling Water Intake Structures at Phase II Existing Facilities, Final Rule. Federal Register, Volume 69, Number 131 (July 9, 2004).
10. USEPA. 2011. National Pollution Discharge Elimination System – Cooling Water Intake Structures at Existing Facilities and Phase I Facilities. Volume 76, Number 76 (April 20, 2011.)

A

ATTACHMENT – EPRI LIST OF ONCE-THROUGH COOLED FACILITIES USING MORE THAN 50 MGD

Steam Electric Generating Stations That Would Have Been Designated Phase II Facilities Under the Remanded Phase II Rule (i.e., use >50 MGD of Cooling Water)
Notes Regarding the List
1. The list contains a small number of facilities that use once through cooling helper towers during a portion of the year.
2. The list is divided into nuclear and fossil facilities. However, three facilities Crystal River, H.B. Robinson and Waterford have both nuclear and fossil units.
3. For the facility to be on the list it must have an active NPDES permit, although the facility may not have operated in the last year or more. Two facilities have NPDES permits that allow once-through cooling that are still under construction.
4. In terms of Water Body Type: R = River, L/R = Freshwater Lake other than a Great Lake or Freshwater Reservoir, GL = Great Lakes and O/E/TR = Oceans/Estuary/Tidal River. The difference between a "Large" and "Small" River is that the mean annual flow of a large river exceeds 10,000 cfs.
5. It is important to note that some of the listed facilities identified as having once through cooling systems withdrawing cooling water from freshwater lakes and reservoirs may in fact be withdrawing from waterbodies that are considered part of a closed-cycle cooling system.
6. Table 1 provides the basis of the flow and MW data shown in columns 7 and 9. The flow basis for each facility is shown in column 6. If the basis of flow and MW data is rated 1 or 2 the facility owner/operator provided Unit specific data, such that the flow and MW data are only for once-through cooling units. If a facility flow basis is rated 3, 4 or 5 it is possible that the flow and MW for the facility include non once-through cooled units.

Table 1 - Priorities for Flow Basis
1 - Highest priority given to flow information provided in cost estimating worksheets specifically provided to inform the study.

2 - Second highest priority given to information provided by the Company or Facility based on 316(b) work that includes - PICs, 122.21r information, technology alternative assessments or other direct information on the facility.
3 - Third highest priority given to flow information provided in Appendix A&B of the Phase II Rule. This informaiton was provided in direct response to a 308 questionnaire.
4 - DOE or Internet

Facility Name	Utility	State	Plant Code	EPAID	Flow Basis	Flow (MGD)	Water Body Type	MW
Nuclear Facilities								
Arkansas Nuclear 1	Entergy	AR			2	1,146	L/R	900
Browns Ferry	Tennessee Valley Authority	AL	46	DUT1050	2	2,851	R (Large)	3,840
Brunswick	Progress Energy Carolinas	NC	6014	AUT0419	1	1,921	O/E/TR	2,060
Calvert Cliffs	Constellation Energy Group	MD	6011	DUT1268	2	3,629	O/E/TR	1,735
Clinton	AmerGen Energy Co LLC	IL	204	AUT0350	1	889	L/R	1,065
Comanche Peak	Luminant Power	TX	6145	DUT1022	2	3,168	L/R	2,300
Cooper	Nebraska Public Power District	NE	8036	AUT0255	2	983	R (Large)	802
Crystal River 3	Progress Energy Florida	FL	628	DUT1029	1	979	O/E/TR	890
Diablo Canyon	Pacific Gas & Electric Co	CA	6099	AUT0012	2	2,500	O/E/TR	2,298
Donald C. Cook	Indiana Michigan Power Co	MI	6000	AUT0202	1	2,369	GL	2,161
Dresden	Exelon Generation Co LLC	IL	869	AUT0364	1	1,898	R (Small)	1,914
Fitzpatrick (James A FitzPatrick)	Entergy Nuc FitzPatrick LLC	NY	6110	AUT0423	2	518	GL	852
Fort Calhoun	Omaha Public Power District	NE	2289	AUT0173	2	518	R (Large)	482
H.B. Robinson	Progress Energy	SC	3251		1	740	L/R	700
Indian Point	Entergy Nuclear Indian Point 2, LLC	NY	2497	AUT0541	2	2,419	O/E/TR	2,028

Kewaunee	Dominion Energy Kewaunee, Inc.	WI	8024	AUT0114	1	582	GL	595
McGuire	Duke Energy Corp	NC	6038	AUT0384	2	2,928	L/R	2,240
Millstone	Dominion Nuclear Conn Inc	CT	566	DUT1070	2	2,190	O/E/TR	2,205
Monticello	Xcel Energy	MN	1922	AUT0588	2	444	R (Large)	620
Nine Mile Point, NY	Constellation Energy Group	NY	2589	AUT0403	2	517	GL	623
North Anna	Dominion Resources, Inc.	VA	6168	AUT0187	1	2,707	L/R	1,956
Oconee	Duke Energy Corp	SC	3265		2	3,058	L/R	2,538
Oyster Creek	AmerGen Energy Co LLC	NJ	2388	DUT1023	2	1,394	O/E/TR	630
Peach Bottom	Exelon Generation Co LLC	PA	3166	AUT0570	2	2,281	L/R	2,186
Pilgrim	Entergy Nuclear Generation Co	MA	1590	AUT0608	2	446	O/E/TR	706
Point Beach	NEXTera Energy	WI	4046	AUT0085	1	1,008	GL	1,365
Prarie Island	Xcel Energy	MN	1925	AUT0181	2	969	R (Large)	1,150
Quad Cities	Exelon Generation Co LLC	IL			2	1,356	R (Large)	1824
R. E. Ginna	Constellation Energy Group	NY	6122	AUT0190	2	536	GL	581
Salem	PSEG Nuclear LLC	NJ	2410	AUT0084	1	3,168	O/E/TR	2,540
San Onofre	Southern California Edison Co	CA	360	AUT0573	2	2,335	O/E/TR	2,150
Seabrook	NEXTera Energy	NH	6115	AUT0275	1	447	O/E/TR	1,296
Sequoyah	Tennessee Valley Authority	TN			2	1,616	L/R	2,442
St Lucie	NEXTera Energy	FL	6045		1	1,403	O/E/TR	1,700
Surry	Dominion Resources, Inc.	VA	3806	DUT1211	1	2,534	O/E/TR	1,802
V C Summer	South Carolina Electric & Gas Co. and SC Public Service Authority	SC	6127		1	720	L/R	1,100
Waterford 3	Entergy Louisiana Inc	LA	4270	AUT0513	2	1,555	R (Large)	1,165
Watts Bar	Tennessee Valley Authority	TN			2	194	L/R	1,270
Wolf Creek	Westar /KCPL	KS	210		2	698	L/R	1,220
Fossil Facilities								
Aguirre	Puerto Rico Electric Power	PR	9999901		2	651	O/E/TR	900
Alamitos	AES Alamitos LLC	CA	315		2	1,181	O/E/TR	1,950
Allen	Tennessee Valley Authority	TN	2718	AUT0551	4	549	R (Large)	864
Allen S King	Xcel	MN	1915	AUT0551	2	467	L/R	605
Allen Steam	Duke Energy Corp	NC	3393		1	861	L/R	1,391
Alma/Magett	Dairyland Power Coop	WI	4140	DUT1021	1	540	R (Large)	605

Anclote	Progress Energy Florida	FL	8048	DUT1275	1	1,287	O/E/TR	1,030
Armstrong	Allegheny Energy Supply Co LLC	PA	3178		2	179	R (Large)	356
Arthur Kill	NRG Arthur Kill Power LLC	NY	2490		2	713	O/E/TR	875
Ashtabula	Cleveland Electric Illum Co	OH	2835		1	252	GL	256
Ashville	Progress Energy Carolinas	NC	2706		1	316	L/R	383
Astoria	Astoria Generating Co LP	NY	8906	AUT0603	3	1,769	O/E/TR	1,330
Avon Lake	RRI	OH	2836	AUT0245	1	625	GL	766
B C Cobb	Consumers Energy Co	MI	1695	AUT0021	2	583	GL	531
B L England (Beesley's Point)	Rockland Capital	NJ	2378	AUT0020	2	299	O/E/TR	299
Bailly	Northern Indiana Pub Serv Co	IN	995	DUT1093	1	490	GL	586
Barney M Davis	Topaz Power Group LLC	TX	4939	DUT1172	4	467	O/E/TR	682
Barry	Alabama Power Co	AL	3		1	1,119	O/E/TR	1,837
Bartow	Progress Energy Florida	FL	634	DUT1274	1	562	O/E/TR	419
Baxter Wilson	Entergy Mississippi Inc	MS	2050	AUT0571	1	297	R (Large)	1,328
Bay Front	Xcel	WI	3982	AUT0499	2	63	GL	76
Bay Shore	First Energy	OH	2878		1	810	GL	849
Beaver Valley	AES Beaver Valley	PA	10676	AUT0125	2	145	R (Large)	125
Belews Creek	Duke Energy Corp	NC	8042		1	1,457	L/R	2,240
Belle River	Detroit Edison Co	MI	6034	AUT0163	2	950	GL	1,270
Big Bend	Tampa Electric Co	FL	645	DUT1165	4	1,396	O/E/TR	1,824
Big Brown	Luminant Power	TX	3497	AUT0449	2	1,015	L/R	1,150
Big Cajun 2	NRG Louisiana Generating LLC	LA	6055	AUT0500	1	380	R (Large)	615
Black Dog	Xcel	MN	1904		2	307	R (Small)	401
Blount Street	Madison Gas & Electric Co	WI	3992	AUT0427	3	170	L/R	195
Bowline Point	Mirant Bowline LLC	NY	2625		2	910	O/E/TR	1,150
Bremo Bluff	Dominion	VA	3796	AUT0396	1	179	R (Small)	250
Bridgeport Harbor	PSEG Power Connecticut LLC	CT	568	AUT0601	1	440	O/E/TR	566
Brooklin Navy Yard Cogen	Olympus Power, LLC	NY	54914	DNU2002	4	99	O/E/TR	80
Brunner Island	PPL Corp	PA	3140		1	795	R (Large)	1,483
Buck	Duke Energy Corp	NC	2720	AUT0490	1	395	R (Small)	487
Bull Run	Tennessee Valley Authority	TN	3396	AUT0024	2	590	L/R	911

Burlington	Interstate Power & Light Co (Alliant Energy)	IA	1104	AUT0585	1	116	R (Large)	212
Burns Harbor	International Steel Group	IN	10245		4	97	GL	176
C D McIntosh	Lakeland Electric Utility	FL	676	AUT0590	3	213	L/R	713
C P Crane	Constellation Power Source Gen	MD	1552	AUT0110	2	446	O/E/TR	385
Cabras	Guam Power Authority	Guam	9999904		2	238	O/E/TR	210
Calaveris (O.W. Summers/J.T. Deely/J.K. Spruce)	CP San Antonio	TX	3611		2	2,249	L/R	3,200
Canaday	Nebraska Public Power District	NE	2226	AUT0246	2	97	R	125
Canal	Mirant Canal LLC	MA	1599		2	580	O/E/TR	1,175
Cane Run	Louisville Gas & Electric Co	KY	1363	AUT0001	1	370	R (Large)	645
Cape Canaveral	NEXTera Energy	FL	609		1	792	O/E/TR	500
Cape Fear	Progress Energy Carolinas	NC	2708	AUT0111	1	342	R (Small)	870
Cardinal	Cardinal Operating Co	OH	2828		1	1,152	R (Large)	1,200
Carl Bailey	Arkansas Electric Coop Corp	AR	202	DUT1170	2	98	R (Large)	124
Cayuga	AES Cayuga LLC	NY	1001		2	245	L/R	306
Cayuga	Duke Energy Corp	IN	2535		2	766	R	1,070
Cedar Bayou	NRG Energy, Inc.	TX	3460	DUT1238	1	1,132	O/E/TR	1,740
Chalk Point LLC	Mirant Mid-Atlantic LLC	MD	1571	AUT0049	2	720	O/E/TR	710
Chamois	Chamois	MO	2169	AUT0254	1	71	R (Large)	70
Charles R Lowman	Powersouth	AL	56	DUT1214	2	78	R	86
Chesapeake	Virginia Electric & Power Co	VA	3803	AUT0002	1	514	O/E/TR	604
Chesterfield	Virginia Electric & Power Co	VA	3797	AUT0299	1	1,091	O/E/TR	1,705
Cheswick	Orion Power Midwest LP - RRI Energy	PA	8226	AUT0106	1	376	R (Large)	637
Clay Boswell	Allete Inc	MN	1893		1	156	L/R	140
Cliffside	Duke Energy Corp	NC	2721	AUT0319	1	269	R (Small)	289
Clifty Creek	Indiana-Kentucky Electric Corp	IN	983		1	1,434	R (Large)	1,306
Coffeen	Ameren Energy Generating Co	IL	861	DUT1152	2	575	L/R	1,005
Colbert	Tennessee Valley Authority	AL	47		2	1,325	R (Large)	1,332
Conesville	Columbus Southern Power Co	OH	2840		1	108	R (Small)	165
Conners Creek	Detroit Edison Co	MI	1726	AUT0285	2	213	GL	239

Contra Costa	Mirant Delta LLC	CA	228	AUT0621	2	440	O/E/TR	690
Costa Sur	Puerto Rico Electric Power	PR	9999908		2	874	O/E/TR	1,086
Covanta Mid-Connecticut Inc	Covanta Energy	CT	54945		3	75	L/R	90
Crawford	Midwest Generation EME LLC	IL	867	AUT0507	1	550	R (Small)	584
Crist	Gulf Power Co	FL	641		1	156	O/E/TR	150
Cromby	Exelon Generation Co LLC	PA	3159	DUT1185	1	359	R (Small)	380
Crystal River 1 and 2	Progress Energy Florida	FL	DUT1029		1	919	O/E/TR	900
Cumberland	Tennessee Valley Authority	TN	3399	DUT1132	2	2,730	R	2,650
Cutler	NEXTera Energy	FL	610	AUT0268	1	213	O/E/TR	237
Dale	East Kentucky Power Coop Inc	KY	1385	AUT0261	3	290	R (Small)	176
Dallman	Springfield City of	IL	963	AUT0537	4	353	L/R	388
Dan E Karn/J.C. Weadock	Consumers Energy Co	MI	1720	DUT1033	1	432	GL	515
Dan River	Duke Energy Corp	NC	2723		1	280	R (Small)	361
Danskammer	Dynegy	NY	2480		2	455	O/E/TR	493
Dave Johnston	PacifiCorp	WY	4158	AUT0583	2	193	R (Small)	454
Decker Creek	Austin Energy	TX	3548	AUT0151	3	695	L/R	726
Deepwater	Conectiv Atlantic Generation LLC	NJ	3461	AUT0370	2	221	O/E/TR	166
Dickerson	Mirant Mid-Atlantic LLC	MD	1572		2	407	R (Small)	576
Dolphus M Grainger	South Carolina Pub Serv Auth	SC	3317	DUT1014	1	116	R (Small)	180
Dubuque	Interstate Power and Light (Alliant Energy)	IA	1046	AUT0277	2	82	R (Large)	77
Dunkirk	NRG Dunkirk Power LLC	NY	2554	AUT0620	2	576	GL	586
E C Gaston	Alabama Power Co	AL	26		1	832	R (Small)	1,000
E D Edwards	Ameren Energy Resources Generating	IL	856	DUT1111	2	579	R (Small)	780
E F Barrett	National Grid/KeySpan	NY	2511	AUT0168	2	294	O/E/TR	380
E S Joslin	NuCoastal Corporation	TX	3436	AUT0493	3	370	O/E/TR	261
E.J. Stoneman	DTE Stoneman, LLC	WI	4146		2	53	R (Large)	53
Eagle Valley-HT Pritchard	AES Corporation	IN	991	AUT0358	2	335	R (Small)	359
East River	Consolidated Edison Co-NY Inc	NY	2493	DUT1143	4	368	O/E/TR	599
Eastlake	First Energy	OH	2837		1	1,146	GL	1,594
Eaton	Southern Co.	MS	2046	AUT0440	1	108	R (Small)	68
Eddystone	Exelon Generation Co LLC	PA	3161	AUT0544	1	1,469	O/E/TR	1,570

Edge Moor	Conectiv Delmarva Generation Inc	DE	593	AUT0539	1	837	O/E/TR	705
Edgewater	Wisconsin Power & Light Co (Alliant Energy)	WI	4050	AUT0036	2	463	GL	770
Edwardsport	Duke Energy Corp	IN	1004		4	187	R (Small)	144
El Segundo	NRG - El Segundo Power LLC	CA	330	DNU2047	2	381	O/E/TR	941
Elk River	GRE	MN	2039	AUT0244	1	73	R (Large)	195
Elmer Smith	Owensboro City of	KY	1374	DUT1041	2	265	R (Large)	441
Elrama	Orion Power Midwest LP - RRI Energy	PA	3098	DUT1047	1	518	R (Large)	510
Encina	NRG	CA	302	AUT0625	2	857	O/E/TR	964
F B Culley	Southern Indiana Gas & Elec Co	IN	1012	AUT0567	3	317	R (Large)	389
Fair Station	Central Iowa Power Coop	IA	1218	AUT0477	4	71	R (Large)	63
Fairless Hills	Exelon Generation Company, LLC	PA	7701		1	78	O/E/TR	60
Far Rockaway	National Grid/KeySpan	NY	2513	DUT1008	2	87	O/E/TR	106
Fayette	LCRA Fayette Power Project	TX	6179		2	1,165	L/R	1,641
Fisk Street	Midwest Generation EME LLC	IL	886	AUT0405	1	323	R (Small)	348
Flint Creek	Southwestern Electric Co	AR	6138		1	412	L/R	559
Forest Grove	Luminant Power	TX	9999925		2	1,470	L/R	1,500
Fort Myers	Florida Power & Light Co	FL	612	AUT0401	1	730	O/E/TR	573
Fox Lake	Interstate Power & Light Co (Alliant Energy)	MN	1888	DUT1175	2	101	L/R	98
Frank E Ratts	Hoosier Energy R E C Inc	IN	1043		2	102	R (Large)	256
G F Weaton	Zinc Corp of America	PA	50130		4	88	R (Large)	120
Gadsden	Alabama Power Co	AL	7		1	219	R (Small)	120
Gallatin	Tennessee Valley Authority	TN	3403	AUT0185	2	916	L/R	1,086
Gary Works	United States Steel Corp	IN	50733		4	122	GL	231
Genoa	Dairyland Power Coop	WI	4143	AUT0538	1	252	R (Large)	360
George Neal North	MidAmerican Energy Co	IA	1091	AUT0397	2	791	R (Large)	1,046
George Neal South	MidAmerican Energy Co	IA	7343		2	468	R (Large)	640
Georgia Pacific Cedar Springs	Georgia-Pacific Corp	GA	54101		4	85	R (Small)	101
Gerald Andrus	Entergy Mississippi Inc	MS	8054	DUT1194	1	260	R (Large)	750
Gerald Gentleman	Nebraska Public Power District	NE	6077	AUT0257	2	760	R	1,444

GEUS	Greenville Electric Util Sys	TX	4195	AUT0481	5	84	L/R	84
Gibbons Creek	Texas Municipal Power Agency	TX	6136		4	418	L/R	454
Glen Lyn	Appalachian Power Co	VA	3776		1	373	R (Small)	335
Glenwood	National Grid/KeySpan	NY	2514	DUT1186	2	179	O/E/TR	218
Gorgas	Alabama Power Co	AL	8		1	979	R	1,221
Gould Street	Constellation Energy Group	MD	1553	AUT0529	2	99	O/E/TR	97
Graham	Luminant Power	TX	3490	DUT1072	2	505	L/R	630
Grand Tower	Ameren Energy Generating Co	IL	862	DUT1012	2	229	R (Large)	199
Grays Ferry	Trigen Phildelphia Energy Corp	PA	54785	DNU2018	3	64	O/E/TR	58
Green Bay West Mill	Fort James Operating Co	WI	10360		4	120	R (Small)	136
Green River	Kentucky Utilities Co	KY	1357	DUT1261	1	177	R (Small)	231
Greene County	Alabama Power Co	AL	10		1	396	R (Small)	500
Greenidge	AES Greenidge LLC	NY	2527		2	146	L/R	107
H.A. Wagner	Constellation Power Source Gen	MD	1554	AUT0174	2	1,060	O/E/TR	982
H L Culbreath Bayside	Tampa Electric Co	FL	646	DUT1066	3	2,465	O/E/TR	685
H.B. Robinson	Progress Energy	SC	3251		1	126	L/R	185
Hamilton	Hamilton City of	OH	2917	AUT0333	3	485	R (Small)	111
Hammond	Georgia Power	GA	708	AUT0131	1	548	L/R	800
Handley	ExTex LaPorte LP	TX	3491	AUT0284	1	1,121	L/R	1,315
Harbor	LADWP	CA	399	DUT1068	2	108	O/E/TR	75
Harbor Beach	Detroit Edison Co	MI	1731	DUT1138	2	130	GL	103
Harding Street	Indianapolis Power & Light Co	IN	990		2	238	R	360
Harllee Branch	Georgia Power	GA	709	AUT0298	1	1,139	L/R	1,735
Hawthorn	Kansas City Power & Light Co	MO	2079	AUT0361	2	283	R (Largel)	693
Haynes	LADWP	CA	400	AUT0387	2	1,014	O/E/TR	1,279
Healy	Golden Valley Electric Association	AK	6288	AUT0381	2	53	R (Small)	75
Hennepin	Dynegy Midwest Generation Inc	IL	892	AUT0004	2	230	R (Small)	293
Henry D King	Fort Pierce Utilities Auth	FL	658	AUT0067	4	108	O/E/TR	114
Hibbard	Minnesota Power Inc	MN	1897		1	236	GL	124
High Bridge	Xcel	MN	1912	AUT0228	2	390	R	510
Honolulu	Hawaiian Electric Co Inc	HI	764	DUT1145	1	184	O/E/TR	103
Hoot Lake	Otter Tail Power Co	MN	1943		4	116	R (Small)	137

Horseshoe Lake	Oklahoma Gas & Electric Co	OK	2951		2	400	L/R	396
Hudson	PSEG Fossil LLC	NJ	2403	DUT1169	1	892	O/E/TR	983
Humboldt Bay	PG&E	CA	246	AUT0517	3	142	O/E/TR	102
Hunlock	UGI	PA			2	61	R (Small)	50
Huntington Beach	AES Huntington Beach LLC	CA	335	AUT0612	2	514	O/E/TR	880
Huntley	NRG Huntley Power LLC	NY	2549	AUT0604	1	346	GL	816
Hutsonville	Ameren Energy Generating Co	IL	863	AUT0385	2	173	R (Large)	167
Iatan	Kansas City Power & Light Co	MO	6065	AUT0398	2	425	R (Large)	706
Indian River	RRI Energy Florida LLC	FL	55318	AUT0496	2	835	R (Small)	609
Indian River	NRG Indian River Operations Inc	DE	594	DUT1206	1	378	O/E/TR	432
J B Sims	Grand Haven BL&P	MI	1825	AUT0241	4	60	GL (Small)	75
J E Corette	PPL Montana LLC	MT	2187	AUT0321	1	75	R (Small)	154
J H Campbell	Consumers Energy Co	MI	1710	AUT0191	1	936	GL	1,440
J M Stuart	Dayton Power & Light Co	OH	2850	DUT1212	1	904	R (Large)	1,869
J R Whiting	Consumers Energy Co	MI	1723	DUT1133	2	323	GL	328
J Sherman Cooper	East Kentucky Power Coop Inc	KY	1384		4	208	R (Large)	341
J.P. Pulliam	Wisconsin Public Service Corp	WI	4072	AUT0157	2	523	GL	373
Jack Watson	Mississippi Power Co	MS	2049	AUT0501	1	441	O/E/TR	512
James De Young	Holland Board of Public Works	MI	1830	DUT1259	3	103	GL	63
James River	Springfield City of	MO	2161	AUT0518	3	279	L/R	253
Jefferies	South Carolina Pub Serv Auth	SC	3319	AUT0522	1	357	O/E/TR	508
John Sevier	Tennessee Valley Authority	TN	3405	DUT1156	2	714	R (Small)	816
Johnsonville	Tennessee Valley Authority	TN	3406	AUT0337	2	1,601	R (Large)	1,408
Joliet 29	Midwest Generation EME LLC	IL	384	AUT0193	1	1,424	R (Small)	1,189
Joliet 9	Midwest Generation EME LLC	IL	874	AUT0205	1	438	R (Small)	341
Joppa Steam	Electric Energy Inc	IL	887	DUT1049	4	589	R (Large)	1,100
Kahe	Hawaiian Electric Co Inc	HI	765	AUT0305	1	847	O/E/TR	650
Kammer	Ohio Power Co	WV	3947		1	713	R (Large)	630
Kanawha River	Appalachian Power Co	WV	3936		1	403	R (Large)	426
Kaw	Board of Public Utilities-City of Kansas	KS	1294	AUT0368	3	120	R	166
Kendall	Mirant Kendall LLC	MA	1595	AUT0623	2	78	R (Small)	67

Kenneth C Coleman	Western Kentucky Energy Corp	KY	1381		4	335	R (Large)	521
Kincaid	Dominion Energy	IL	876		1	461	L/R	1,182
Kingston	Tennessee Valley Authority	TN	3407	AUT0552	2	1,495	R (Small)	1,677
Knox Lee	Southwestern Electric Power Co	TX	3476	DUT1248	1	639	L/R	500
Kraft	Savannah Electric & Power Co	GA	733		1	259	O/E/TR	479
Kyger Creek	Ohio Valley Electric Corp	OH	2876	AUT0564	1	1,166	R (Large)	1,085
Kyrene	Salt River Proj Ag I & P Dist	AZ	147		2	96	OTHER	96
La Cygne	Kansas City Power & Light Co	KS	1241		2	726	L/R	1,418
Labadie	Ameren UE	MO	2103	DUT1046	2	1,233	R (Large)	2,560
Lake Catherine	Entergy Arkansas Inc	AR	170	AUT0073	2	565	L/R	673
Lake Hubbard	Luminant Power	TX	3452	AUT0027	2	870	L/R	921
Lake Road	Kansas City Power & Light Co	MO	2098	AUT0127	2	86	R(Large)	99
Lake Shore	Cleveland Electric Illum Co	OH	2838		1	246	GL	256
Lansing	Interstate Power & Light Co (Alliant Energy)	IA	1047	AUT0304	2	299	R (Large)	317
Lansing Smith	Southern Co.	FL	679	AUT0304	1	260	O/E/TR	384
Lauderdale	Florida Power & Light Co	FL	613	AUT0142	1	368	O/E/TR	312
Leland Olds	Basin Electric Power Coop	ND	2817	DUT0062	1	330	R (Large)	656
Lieberman	SWEPCO	LA	1417		1	134	L/R	286
Little Gypsy	Entergy Louisiana Inc	LA	1402	AUT0097	1	468	R (Large)	1,251
Lonestar	Southwestern Electric Power Co	TX	3477	AUT0080	4	79	L/R	40
Maine Energy Recovery Co	Central Maine Power Co	ME	10338	DNU2013	3	94	O/E/TR	22
Manchester Street	Narraganset Electric Co	RI	3236		1	259	O/E/TR	168
Mandalay	RRI Energy Mandalay LLC	CA	345	AUT0638	2	254	O/E/TR	430
Manitowoc	Manitowoc Public Utilities	WI	4125	DUT1202	3	52	GL	79
Marion	Southern Illinois Power Coop	IL	976	AUT0222	3	225	L/R	272
Marshall	Duke Energy Corp	NC	2727	AUT0260	2	1,463	L/R	2,090
Martin Lake	Luminant Power	TX	6146	AUT0176	2	2,411	L/R	2,250
Marysville	Detroit Edison Co	MI	1732		4	368	GL	84
McClellan	Arkansas Electric Coop Corp	AR	203	DUT1154	2	71	R (Small)	136
McIntosh	Georgia Power	GA	6124		1	91	R (Small)	167
McManus	Georgia Power	GA	715		1	166	O/E/TR	115
Meramec	Ameren UE	MO	2104	DUT1192	2	675	R (Large)	1,035

Mercer	PSEG Fossil LLC	NJ	2408	AUT0058	1	691	O/E/TR	648
Meredosia	Ameren Energy Generating Co	IL	864	AUT0146	2	392	R (Large)	354
Merom	Hoosier Energy R E C Inc	IN	6213	AUT0406	1	484	L/R	1,139
Merrimack	Public Service Co of NH	NH	2364	DUT1031	3	287	R (Small)	474
Miami Fort	Duke Energy Corp	OH	2832	AUT0472	2	130	R (Large)	163
Michoud	Entergy New Orleans Inc	LA	1409	AUT0047	2	763	O/E/TR	918
Mid Connecticut Resource Recovery Facility	Connecticut Resources Recovery Authority	CT	9999926		4	108	R(Large)	90
Middletown	NRG Middletown Power LLC	CT	562	AUT0577	1	224	R (Large)	353
Mill Creek	Louisville Gas & Electric Co	KY	1364	DUT1153	1	233	R (Large)	419
Milton L Kapp	Interstate Power & Light Co (Alliant Energy)	IA	1048	AUT0443	2	197	R (Large)	255
Milton R Young	Minnkota Power Coop Inc	ND	2823	DUT1103	1	530	L/R	700
Missouri City	Independent Blue Valley Power Plant	MO	2171	AUT0078	3	416	R (Largel)	46
Mistersky	Detroit City of	MI	1822	AUT0433	4	198	GL	189
Mitchell	Georgia Power	GA	727	AUT0137	1	173	R (Small)	125
Mitchell	Allegheny Energy Supply Co LLC	PA	3181	AUT0404	2	255	R (Large)	365
Monroe	Detroit Edison Co	MI	1448	DUT1002	3	2,010	GL and R	3,110
Monticello	Luminant Power	TX	6147	DUT1272	2	1,732	L/R	1,880
Montrose	Kansas City Power & Light Co	MO	2080	AUT0341	2	370	L/R	510
Montville	NRG Montville Power LLC	CT	546	AUT0013	1	315	O/E/TR	516
Morgantown	Dominion Energy Services Company, Inc.	WV	10743	AUT0278	1	80	R (Large)	58
Morgantown	Mirant Mid-Atlantic LLC	MD	1573	DNU2021	2	1,234	O/E/TR	1,248
Morro Bay	Dynegy	CA	259	AUT0613	2	453	O/E/TR	600
Moss Landing	Dynegy	CA	260	AUT0607	1	1,224	O/E/TR	1,899
Mount Tom	Northeast Generation Services Co	MA	1606	AUT0134	3	143	R (Large)	144
Mountain Creek	ExTex LaPorte LP	TX	3453	DUT1187	1	722	L/R	810
Mt Storm	Virginia Electric & Power Co	WV	3954	AUT0178	1	1,184	L/R	1,693
Muscatine Plant #1	Muscatine City of	IA	1167	AUT0033	4	288	R (Large)	294
Muskingum River	Ohio Power Co	OH	2872	AUT0547	1	864	R (Small)	840
Muskogee	Oklahoma Gas & Electric Co	OK	2952	DUT1252	2	107	R (Small)	180

Mystic (Unit 7)	U.S. Power Gen	MA	1588		4	646	O/E/TR	560
Natrium Plant	PPG Industries Inc	WV	50491		4	65	R (Large)	123
Nebraska City	Omaha Public Power District	NE	6096	AUT0394	2	432	R (Large)	653
Nelson Dewey	Wisconsin Power & Light Co (Alliant Energy)	WI	4054	AUT0053	2	167	R (Large)	200
New Castle Plant	RRI Energy	PA	3138	AUT0208	1	253	R (Small)	348
New Haven Harbor	PSEG Power Connecticut LLC	CT	6156	AUT0618	1	404	O/E/TR	466
New Madrid	Associated Electric Coop Inc	MO	2167	AUT0171	1	864	R (Large)	1,200
Newington	Public Service Co of NH	NH	8002		4	325	O/E/TR	422
Newton	Ameren Energy Generating Co	IL	6017		2	806	L/R	1,288
Niles	RRI	OH	2861		1	403	R (Small)	266
Nine Mile Point	Entergy Louisiana Inc	LA	1403	AUT0403	1	611	R (Large)	1,566
Noblesville	Duke Energy Corp	IN	1007	AUT0416	3	207	R (Small)	100
North Omaha	Omaha Public Power District	NE	2291	AUT0266	2	529	R (Large)	664
North Texas	Brazos Electric Power Coop Inc	TX	3627	DUT1038	3	95	L/R	71
Northport	National Grid/KeySpan	NY	2516	AUT0015	2	926	O/E/TR	1,500
Northside	JEA	FL	667	AUT0568	1	648	O/E/TR	1,159
Norwalk Harbor	NRG Norwalk Harbor Power LLC	CT	548	AUT0120	2	312	O/E/TR	330
O H Hutchings	Dayton Power & Light Co	OH	2848	DUT1198	3	403	R	399
Oak Creek	Wisconsin Electric Power Co	WI	4041	DUT1034	1	1,181	GL	1,139
Oak Grove	Luminant Power	TX	9999927		2	1,610	L/R	1,710
Ormond Beach	RRI Energy Ormond Beach, Inc.	CA	350	AUT0637	2	685	O/E/TR	1,516
Oswego Harbor	NRG Oswego Power LLC	NY	2594	AUT0071	1	1,132	GL	1,740
Otto E. Eckert	Lansing Board of Water and Light	MI	1831	AUT0300	2	233	R (Small)	330
P H Robinson	NRG Energy, Inc.	TX	3466	DUT1155	1	1,681	O/E/TR	2,285
Palo Seco	Puerto Rico Electric Power	PR	9999920		2	654	O/E/TR	602
Paradise	Tennessee Valley Authority	KY			2	608	R(Small)	2,427
Peru	Peru Light & Power Co	IN	1037	DUT1003	3	55	R (Large)	35
Petersburg	Indianapolis Power & Light Co	IN	994	DUT1085	2	428	R (Large)	880
Philip Sporn	Central Operating Co	WV	3938	AUT0314	1	1,038	R (Large)	1,050
Picway	Columbus Southern Power Co	OH	2843		1	101	R (Small)	100
Pirkey	SWEPCO	TX	7902		1	544	L/R	700

Pittsburg	Mirant Delta LLC	CA	271	AUT0639	2	462	O/E/TR	645
Port Everglades	Florida Power & Light Co	FL	617		1	1,253	O/E/TR	1,254
Port Jefferson	National Grid/KeySpan	NY	2517		2	294	O/E/TR	380
Port Washington	Wisconsin Electric Power Co	WI	4040	DUT1219	1	814	GL	1,206
Portland	RRI Energy Mid-Atlantic PH	PA	3113	AUT0351	1	314	R (Small)	427
Possum Point	Virginia Electric & Power Co	VA	3804	AUT0270	1	224	O/E/TR	313
Potomac River	Mirant Mid-Atlantic LLC	VA	3788	AUT0554	2	450	O/E/TR	510
Prairie Creek	Interstate Power & Light Co (Alliant Energy)	IA	1073	AUT0181	2	205	R (Small)	238
Presque Isle	Wisconsin Electric Power Co	MI	1769	DUT1007	1	350	GL	450
Quindaro	Kansas City City of	KS	1295	AUT0297	3	265	R (Large)	239
R A Reid	Big River Energy Corp.	KY	1383		5	130	R (Small)	96
R E Burger	Ohio Edison Co	OH	2864	AUT0175	1	225	R (Large)	416
R Gallagher	Duke Energy Corp	IN	1008		2	436	R (Large)	616
R M Heskett	MDU Resources Group Inc	ND	2790	DUT1154	4	64	R (Large)	115
R Paul Smith	Allegheny Energy Supply Co LLC	MD	1570		2	103	R (Small)	116
R W Miller	Brazos Electric Power Coop Inc	TX	3628	AUT0192	4	396	L/R	604
Ravenswood	TransCanada	NY	2500	AUT0617	2	1,390	O/E/TR	1,752
Ray Olinger	Garland City of	TX	3576	DUT1043	2	357	L/R	345
Red Wing	Xcel	MN	1926		2	50	R	26
Redondo Beach	AES Redondo Beach LLC	CA	356		1	891	O/E/TR	1,310
Richard Gorsuch	American Mun Power-Ohio Inc	OH	7286	AUT0446	1	187	R (Large)	213
River Rouge	Detroit Edison Co	MI	1740	AUT0276	2	441	GL	540
Riverbend	Duke Energy Corp	NC	2732		1	415	L/R	470
Riverside	Constellation	MD	1927	AUT0203	2	61	O/E/TR	78
Riverside	MidAmerican Energy Co	IA	1081	AUT0203	2	90	R	141
Riverside	Xcel	MN	1559	AUT0203	2	277	R (Large)	420
Riverton	Empire District Electric	KS	1239	DUT1229	3	105	R	88
Rivesville	Monongahela Power Co	WV	3945		2	119	R (Large)	137
Riviera	NEXTera Energy	FL	619		1	565	O/E/TR	600
Robert E Ritchie	Entergy Arkansas Inc	AR	173	DUT1161	1	454	R (Large)	919
Roseton	Dynegy	NY	8006	AUT0411	2	924	O/E/TR	1,185
Roxboro	Progress Energy Carolinas	NC	2712		1	1,096	L/R	1,775

Rush Island	Ameren UE	MO	6155	AUT0536	2	1,097	R (Large)	1,340
S O Purdom	Tallahassee City of	FL	689	DUT0576	3	134	O/E/TR	137
Sabine	Entergy Gulf States Inc	TX	3459	AUT0315	1	1,275	L/R	2,167
Salem Harbor	Dominion	MA	1626	AUT0631	3	692	O/E/TR	745
Sam Gideon/Lost Pines 1	LCRA	TX	3601	DUT1273	2	950	L/R	1,165
San Juan	Puerto Rico Electric Power	PR	9999924		2	749	O/E/TR	534
Sanford	Florida Power & Light Co	FL	620		1	167	R (Small)	156
Scattergood	Los Angeles City of	CA	404	AUT0068	2	495	O/E/TR	838
Schiller	Public Service Co of NH	NH	2367	AUT0083	4	153	O/E/TR	160
Scholz	Southern Co.	FL	642		1	130	R (Large)	80
Schuylkill	Exelon Generation Co LLC	PA	3169	AUT0183	1	207	O/E/TR	228
Seminole	Oklahoma Gas & Electric Co	OK	2956		2	1,434	L/R	1,500
Sewaren	PSEG Fossil LLC	NJ	2411	DUT1100	1	542	O/E/TR	428
Shawnee	Tennessee Valley Authority	KY	1379	AUT0483	2	1,613	R (Large)	1,610
Shawville	RRI Energy Mid-Atlantic PH	PA	3131	AUT0011	1	656	R (Large)	626
Shiras	Marqutte Board of Light and Power	MI	1843	AUT0435	3	264	GL	78
Sibley	Kansas City Power & Light Co	MO	2094	DUT1227	2	293	R (Large)	466
Silver Bay Power	Cleveland Cliffs Inc	MN	10849		4	151	GL	132
Silver Lake	Rochester Public Utilities	MN	2008	AUT0227	3	119	L/R	106
Sioux	Ameren UE	MO	2107	AUT0072	2	749	R (Large)	1,100
Somerset (Formerly Kintigh)	AES Somerset LLC	NY	6082		2	274	GL	675
Somerset	NRG Somerset Power LLC	MA	1613	AUT0384	4	274	O/E/TR	174
Sooner	Oklahoma Gas & Electric Co	OK	6095		2	789	L/R	1,096
South Bay	Dynegy	CA	310		1	517	O/E/TR	696
SR Bertron	NRG Energy, Inc.	TX	3468	AUT0248	1	740	O/E/TR	861
St Clair	Detroit Edison Co	MI	1743	DUT1258	1	1,111	GL	1,414
Stanton	Great River Energy	ND	2824	AUT0273	1	144	R (Largel)	202
State Line Energy	State Line Energy LLC	IN	981		1	621	GL	1,711
Sterlington	Entergy Louisiana Inc	LA	1404	DUT1157	1	158	R (Small)	224
Stryker Creek	Luminant Power	TX	3504	DUT1011	2	527	L/R	675
Sunbury Gen	Corona Power LLC	PA	3152		4	296	R (Large)	425
Suwannee	Progress Energy Florida	FL	638	AUT0051	1	261	R (Small)	217
Syl Laskin	Allete Inc	MN	1891		1	136	L/R	110

Taconite Harbor	Allete Inc	MN	10075		1	184	GL	225
Tanners Creek	Indiana Michigan Power Co	IN	988	AUT0148	1	1,066	R (Large)	995
Teche	Cleco Power LLC	LA	1400	AUT0362	3	451	O/E/TR	428
Tennessee Eastman Operations	Eastman Chemical Co-TN Ops	TN	50481		4	674	R	194
Thames	AES Thames LLC	CT	10675		2	156	R (Small)	181
Thomas B Fitzhugh	Arkansas Electric Cooperative Corp	AR	201		2	61	R (Small)	60
Thomas C Ferguson	Lower Colorado River Authority	TX	4937		4	397	L/R	446
Thomas Hill	Associated Electric Coop Inc	MO	2168	AUT0149	1	1,002	L/R	1,197
Trenton Channel	Detroit Edison Co	MI	1745	AUT0575	2	516	GL	730
Trinidad	Luminant Power	TX	3507	AUT0476	2	285	L/R	240
Twin Oaks	Sempra	TX			5	305	L/R	330
Tyrone	Kentucky Utilities Co	KY	1361	AUT0095	1	79	R (Small)	75
University of Notre Dame	Indiana Michigan Power Co	IN	50366	DMU3244	3	113	L/R	21
Urquhart	South Carolina Electric&Gas Co	SC	3295	AUT0535	1	190	R (Small)	243
V H Braunig	CP San Antonio	TX	3612		2	1,277	L/R	1,401
Valley	Wisconsin Electric Power Co	WI	3508	AUT0161	1	158	GL	280
Valmont	Xcel	CO			2	194	L/R	186
Vero Beach	Vero Beach City of	FL	693	AUT0467	4	144	O/E/TR	117
Victoria	Topaz Power Group LLC	TX	3443	DUT1142	4	557	R	80
W H Sammis	Ohio Edison Co	OH	2866		1	1,353	R (Large)	2,219
W S Lee	Duke Energy Corp	SC	3264	AUT0308	1	331	R (Small)	424
Wabash River	Duke Energy Corp	IN	1010		2	747	R (Large)	764
Waiau	Hawaiian Electric Co Inc	HI	766	DUT1116	1	430	O/E/TR	397
Walter C Beckjord	Duke Energy Corp	OH	2830	AUT0523	1	741	R (Large)	1,222
Walter Scott Jr. (Council Bluffs)	MidAmerican Energy Co	IA	1082	DUT1148	2	792	R (Largel)	821
Warrick	Alcoa Power Generating Inc	IN	6705	AUT0462	4	281	R (Large)	755
Waterford 1 & 2	Entergy Louisiana Inc	LA	8056	AUT0156	1	822	R (Large)	912
Waukegan	Midwest Generation EME LLC	IL	883	DUT1123	1	731	GL	736
Welsh	SWEPCO	TX	6139		1	1,218	L/R	1,674
West Springfield	North American Energy Alliance	MA	1642		4	69	R (Large)	214

Westchester Resco Co	Westchester Resco/Wheelabrator	NY	50882	DNU2017	3	55	O/E/TR	75
Weston	Wisconsin Public Service Corp	WI	4078	AUT0344	2	118	R (Small)	135
Westover	AES Westover LLC	NY	2526		2	97	R (Large)	82
Widows Creek	Tennessee Valley Authority	AL	50	DUT1209	2	1,645	R (Large)	1,761
Wilkes	SWEPCO	TX	3478		1	539	L/R	888
Will County	Midwest Generation EME LLC	IL	884	AUT0380	1	1,296	R (Small)	1,300
Williams	South Carolina Genertg Co Inc	SC	3298	AUT0014	1	534	L/R	656
Willow Glen	Entergy Gulf States Inc	LA	1394	DUT1228	1	1,002	R (Large)	2,045
Willow Island	Monongahela Power Co	WV	3946		2	205	R (Large)	245
Wood River	Dynegy Midwest Generation Inc	IL	898	AUT0143	2	340	R (Large)	460
Wyandotte	Wyandotte City of	MI	1866	AUT0050	4	112	GL	73
Wyman	NEXTera Energy	ME	1507		1	263	O/E/TR	837
Yorktown	Virginia Electric & Power Co	VA	3809		1	1,382	O/E/TR	1,230

B
ATTACHMENT - PLANT OUTAGE ACTIVITIES REQUIRED TO RETROFIT CLOSED-CYCLE COOLING SYSTEMS

PLANT OUTAGE ACTIVITIES REQUIRED TO RETROFIT CLOSED-CYCLE COOLING SYSTEMS

Final Report

March 15, 2011

DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

THE FOLLOWING ORGANIZATION(S), UNDER CONTRACTO TO EPRI, PREPARED THIS REPORT:

Burns Engineering Services, Inc.

NOTE

For further information about EPRI, call the EPRI Customer Assistance Center at 800.313.3774 or e-mail askepri@epri.com.

ACKNOWLEDGMENTS

The following organizations, under contract to the Electric Power Research Institute (EPRI), prepared this report:

Burns Engineering Services, Inc.
Unit 1
30 Hathorne Street
Salem, MA 01970
Tel: (978) 741-2648
Web: www.BurnsEngr.com

Principal Investigators
J. S. Burns
J. M. Burns

This report describes research sponsored by EPRI.

This publication is a corporate document that should be cited in the literature in the following manner:

Report on Plant Outages Required to Retrofit Closed-Cycle Cooling Systems. EPRI, Palo Alto, CA: 2011. EP-P38757/C17239.

PRODUCT DESCRIPTION

The Electric Power Research Institute (EPRI) is investigating implications of a potential EPA Clean Water Act §316(b) rulemaking that may establish "Best Technology Available" (BTA) based on closed-cycle cooling retrofits for facilities with once-through cooling. This report focuses on the extent of the in-plant activities required to complete the installation of a retrofitted cooling system. Ranging from constructing new circulation water pump basins with their pumps, to the demolition of inapplicable once-through features, to modified make-up intakes, to re-optimizing the entire cooling system design. The report covers the effort involved in most of the possible cut-in situations that may occur. The information provided should both inform the rule-making and allow power plant personnel to make suitable plans and supply bases for accurate estimates of the time & cost impacts of the generally long duration outages that are needed.

Scope and Findings

It was determined that, because there has been insufficient actual experience in retrofitting closed-cycle cooling systems to power plants, there are no general rules; each estimate must be tailored to the particulars of the plant, its size, and the site conditions. As a result, the report divided the retrofits into two broad categories that involved either a separate cooling loop mostly outside the structures of the plant or a cooling loop that was an extension of the existing cooling system. The construction and demolition requirements for fossil fired plants that would necessitate an extended plant shutdown are discussed. The extended outage needs of nuclear plants are also outlined. The reasons the retrofit of closed-cycle cooling systems to a multiple unit station require longer shutdowns are delineated. The added construction activities of a re-optimized closed-cycle cooling system are presented and as such, considered to further increase the retrofit outage.

Challenges and Objectives

Retrofitting a closed-cycle cooling system to a power plant designed for and currently using a once-through cooling system is a complex engineering challenge. The engineering challenges are magnified by the fact that only a few actual retrofits have been completed at once-through cooled plants, thereby limiting the availability of practical knowledge to inform the process. The objective of this document is to allow an accurate projection of what needs to be done at a particular station to complete the retrofit of the closed-cycle cooling system by providing the elements of the construction that are needed during a plant shutdown to complete installation of the closed-cycle cooling system. Since the methods of how to get the project accomplished expeditiously are related to the time of the project, these are the focus. Unfortunately, it was found that because there is little actual retrofit experience in this field, only a plant and site-specific plan can developed and then subsequently quantified. There are no general rules. Clearly, however, there is potential that the station outage could be lengthy.

Applications, Values, and Use

The application of information outlined in this report will provide the ingredients needed to consider the wet cooling tower, closed-cycle retrofit cut-in time and associated information for small and large fossil and nuclear stations for:

- Retrofitted cooling systems installed within a separate loop outside the existing plant buildings.
- Retrofitted cooling systems installed as a part of the existing plant cooling system utilizing modified components like pumps or piping within the plant buildings.
- Multiple unit stations.
- All types of plant sites except those where land is not available in urban settings.
- The information provided will establish a basis to determine an accurate estimate of the cut-in time and it will be instrumental in supplying factual information to avoid a biased estimate that overlooks most of the construction requirements. Both wet-mechanical draft and natural draft towers are included within the scope.

EPRI Perspective

EPRI's R&D efforts focus on providing sound technical information to support environmental regulation development and debate as well as technology improvements to support the generation, distribution and use of electricity. This report is one of a series that provides information related to the Clean Water Act §316(b) Existing Facility Rule development process. Information in this report provides regulators, industry and other stakeholders with detailed information on activities required to complete the installation of a retrofitted cooling system.

Approach

The Project Team identified all practical types of wet, retrofit closed-cycle cooling systems. The Team recognized that an estimate is too site-specific to allow any meaningful discussion, considering the broad variety of stations at which the system would be applied and the conceptual cooling system designs that would be utilized. The Team then addressed the equipment and component details within the station that would require modification for each type of generalized conceptual design. Adding the influence of a typical project management/work chain would allow an assessment of the total outage times at a particular plant. The effects of retrofitting on plant performance or output were not addressed. A discussion of the effect of re-optimization of the cooling system size was also included. The re-optimized design would alter the existing condenser and/or pumps but would be necessary when the size of the retrofitted cooling tower became excessive or other constraints ruled. Because there are more construction activities, re-optimized retrofitted closed-cycle cooling system would further increase the duration of a plant shutdown. The adverse effects of multiple unit sites on station shutdowns to conduct closed-cycle cooling system retrofit construction activities were also included.

Keywords
Cooling Tower Retrofit
Clean Water Act §316
Closed-cycle cooling
Cooling towers
Fish Protection

CONTENTS

1
INTRODUCTION

It is a basic consequence of the laws of mid-nineteenth century science of thermodynamics that all heat engines release substantial quantities of low energy, "waste heat" to the environment. Steam-electric power plants are heat engines and so create waste heat that is transported to its local surroundings by their cooling systems. If there was sufficient water available, plants typically employed once-through water cooling systems to provide the necessary cooling, because once-through cooling systems provide the simplest, most efficient, and most cost-effective plant cooling. Once-through cooling systems use the nearby water source and require relatively large quantities of water heated from about 8° F to 30° F. The cooling water is conveyed from an intake through the plant by large pumps to the steam surface condenser that collects most of the waste heat and then back to the same source body of water via a discharge facility exiting the plant. This system also supplies cooling needs to all the auxiliary equipment of the plant. As a consequence, the cooling system is one of the most basic, physically largest and sprawling systems within a power plant. Much like the main powerhouse structures, it was designed by the architect-engineer to be a permanent fixture that would not be modified during the life of the plant. No provisions were included either to enable a modification of the essential characteristics of the cooling system and there was no expectation that provisions of the Clean Water Act in the future would require any fundamental changes.

The Clean Water Act (CWA) of 1972, required utilities to incorporate into their plant designs methods and equipment that would implement the requirements of Section 316(b). Section 316(b) requires facilities to use "best technology available" (BTA) to minimize adverse environmental impact as a result of the location, design, construction and capacity of the cooling water intake structure. However, EPA never implemented regulations to comply with the statute until 2004 and those regulations were withdrawn in 2007 as a result of a Second Circuit Court ruling. EPA is currently in the process of developing new regulations. EPA is considering closed-cycle cooling as one option for BTA.

A potentially significant cost to retrofit some facilities with closed-cycle cooling is the time it takes to connect the retrofitted closed-cycle system to the existing plant cooling system. This report is limited to that effort. It assumes a retrofitted closed-cycle cooling system that utilizes a wet mechanical or wet natural draft tower. Though this report on the length of shutdowns generally assumes a single unit plant, the particular problems of retrofitting multiple units to closed-cycle cooling systems are considered.

Due to their huge size and the enormous vacuum rated steam ducts that must be carried from the exhaust of the turbine to the tower outside, direct dry cooling towers are not considered suitable for a retrofit cooling system application. And because of the lack of precedence in the US, the potential for unreliability and freezing of the heat transfer sections, the size and their very poor performance, indirect dry cooling towers are considered impractical candidates to use in a retrofit cooling system design. Neither is addressed in this report.

Avoiding the use of absolutes, the report will discuss the aspects of the construction and demolition during the new cycle connection to enable a reasonable perspective and follow-on estimate on the outage time that would be involved in the three major retrofit system design classifications:

- The cooling tower is on a separate cooling loop external and essentially independent of the existing plant structures and components. The warmed cooling water discharge is delivered to an intermediate cooling tower pump basin and thence to the tower. Cooled water is returned to the vicinity of the existing circulating water (CW) pump suction, conveyed by the original pumps through the condenser and to the external basin where the cycle is repeated. In this case, neither condenser, nor existing system piping nor components are subject to high hydraulic pressures. This design concept constitutes the least obtrusive retrofit and would generally be associated with the shortest plant outage.
- The cooling tower is on an integral cooling loop that is not independent of the existing plant structures and components. The warmed cooling water discharge is delivered directly to the cooling tower. Cooled water is returned to the vicinity of the existing circulating water (CW) pump suction, conveyed by new, higher energy pumps through the condenser and back to the tower where the cycle is repeated. In this case, the condenser, existing system piping and components are subject to comparatively high hydraulic pressures. This design concept is conceptually simple but results in an obtrusive retrofit that would usually require longer plant outages.
- For reasons of improved overall efficiency, to accommodate the size or plant site layout constraints or the type of cooling tower, the quantity of cooling water is changed. This modification would then fold into an appropriate retrofit cooling system design as outlined by the above two categories.

This document contributes to the EPRI objective of providing sound technical information by outlining the many construction and demolition activities required to retrofit a typical plant to closed-cycle cooling. These activities can be used to form the basis of subsequent estimates of the duration of the plant shut down outage.

2
FEATURES OF CONCEPTUAL RETROFIT CLOSED-CYCLE COOLING DESIGNS

Most existing once-through cooling systems utilize a siphon circuit type of hydraulic design. Cooling water pumps just after the intake, transport the cooling water from the source water at a sufficient head only to overcome the friction and form losses of the system components. The warmed water after the condenser flows back to the source by gravity down the siphon formed by the condenser's slightly higher elevation above the water body. Consequently, all elements of the cooling water systems, including the piping, valves, and condenser, were designed for low pressures. In contrast, a new closed-cycle cooling system would usually be designed for the much higher hydraulic pressures required by the elevation of the cooling tower fill distribution level and the much longer runs of piping involved to get to the tower. The pumps would be of a correspondingly higher horsepower.

That fundamental difference is one of the focuses of the strategy of a closed-cycle design: to the extent possible, it must accommodate the lower hydraulic pressures of the existing design or otherwise risk building more structural and mechanical integrity into that former system. The latter design and field modifications are not simple to accomplish because the pipe is buried and perhaps of an uncertain pressure rating while the condenser materials and method of tube-to-tubesheet joints could be of a limited pressure capability. Simply stated, it is an easier retrofit design philosophy to minimize exposing the existing system to the higher retrofit pressures and employ a strategy that will minimize the work necessary inside the plant during the outage to complete the retrofit.

Another important characteristic of the steam-electric cooling system design is that the inlet and outlet are well separated to prevent co-mingling the intake water with the warm water discharge. That usually means that though they are essentially brought together to form a loop of sorts, the discharge and intake are initially at a great distance from one another. That increases the retrofit designer's difficulty of adopting a closed-cycle design. In addition, the condenser is directly under the steam turbine at what is essentially the center of the power plant. At the heart of the plant then, it is surrounded by piping, equipment etc., so that modifications may not be easily made. This extra complexity must be accounted for in any retrofit design.

Finally, many steam-electric power stations are comprised of multiple units. This exacerbates the problems of developing suitable closed-cycle retrofit designs, and considerably lengthens the cut-in time for the retrofits. In most instances, multiple units at the same site are clustered together and laid out side-by-side. Once-through cooling systems of multi-unit stations often use common intake bays, cooling canals, and/or even intakes/discharges. Despite the sharing of these CWS elements, and their being built in close proximity to one another, each unit is capable of proper operation and isolation from the neighboring units. When retrofitted closed-cycle cooling systems replace the existing ones however, a wide separation of the cooling systems is needed to maintain the same requirements for independent operation. Only a few minor common facilities such as makeup and blowdown can be erected; most of the major equipment and components that will be retrofitted need space and clear separations from the other units. The large amount of land needed for each cooling tower, the modified pump and motor requirements, electrical and piping conduits make the separate retrofits difficult to site. Whether retrofitting all units at the same station in the same time period, or separately, the original closeness of the major cooling system components significantly affects the demolition and construction on each. The proximity of each unit's CWS to each other will impact the efficiency of the retrofit work or the operation on the neighboring unit. Therefore, the overall time of the plant outage well beyond that of the retrofit a single unit closed-cycle system will be extended.

As a result, the details of the category of the retrofit design will have an important influence on the outage time as well as the plant specifics to make and test-out the numerous plant connections. Hence, the descriptions of the retrofit closed-cycle system design categories outlined in the Introduction will be expanded upon in this section.

Tower on Separate Cooling Loop External to Existing Plant

In this instance, the retrofit cooling system design loop would be located outside the existing plant structures. Figure 2-1 schematically depicts the concept. Usually this type of retrofit closed-cycle cooling system design can be utilized if there is ample room on the property and there were no unusual features in the existing cooling system such as an underwater diffuser well off-shore. Much of the retrofit work can be accomplished without impacting the normal operation or schedule of the station. The plant net output would be reduced by several effects: the extra auxiliary power required by the differential power use of the new pumps compared to the existing ones; makeup and blowdown pump power; mechanical draft cooling tower fan power, if applicable; miscellaneous small motors; and the loss in steam turbine performance due to the higher condenser backpressures resulting from the higher cooling water temperatures delivered by the tower relative to once-through cooling water.

This retrofit design consists of a separate cooling circuit from a new external cooling tower pump basin to the tower and back to the vicinity of the original CW pump bay. The existing CW pumps would convey the cooling water from a slightly modified suction/pump bay through the condenser to this intermediate basin. The head necessary to transfer the cooling water to the basin should be similar to the original head specification for the CW pumps. Throttling should not be necessary since this represents a loss in station energy. Approximately the same quantity of cooling water would be employed in the retrofit as in the original design. The CW flow from the tower back to the modified pump suction would be via gravity or a set of low lift pumps if required. Both the modified CW suction pump basin and the cooling tower basin would be generously sized to avoid hydraulic instability in the two circuits. Sufficient local electrical power and controls would be needed to be brought from the switchyard to the cooling tower pump basin. If a mechanical draft tower is retrofitted, the cooling fan motor control center would also need to have a similar set of cabling, controls and switchgear. The pump voltage would be usually 4160 while the fan motor voltage would be typically 460 and that would change the potential location and difficulty related to identifying the proper auxiliary power source within the existing plant.

The cooling tower makeup would be introduced into the modification of the original pump suction bay. Depending on the site auxiliary cooling system, it may first be routed through some heat exchangers in order take advantage of its cooler temperatures. This would be a separate, small intake for the makeup that is designed to be environmentally friendly. Usually it would be in the same location as the original intake. Cooling tower makeup water pumps would also be necessary. The tower blowdown would be taken from some convenient location ranging from the cooling tower cold water basin to the modified CW pump bay for environmental stewardship reasons to minimize the temperature of that water discharged back into the source body. Periodically, as a result of salt and sediment build up in the re-circulating water, the water must be discharged (termed "blowdown") which may require another small pump station.

It would further be necessary to demolish all obsolete once-through components, materials and equipment that are no longer used such as the intake structure, bar-racks, discharge, diffusers, and piping. While some of this work could occur after the outage, most would be required to be completed during the shutdown to prevent interference with the subsequent plant operation.

Tower on Extended Cooling Loop from Existing Plant

In this instance, the retrofit closed-cycle cooling system design loop would be an extension of the original system modified within the plant structures to encompass the retrofitted cooling tower that is situated outside the existing plant structures. Figure 2-2 schematically depicts the concept. This type of retrofit closed-cycle cooling system design would be utilized when there are unusual features at either the site or within the plant that prohibit a separate cooling circuit for the tower. Those unusual features might be a tight site, one with a significant change in elevation or the existing intake and/or discharge having a difficult access. Though conceptually simpler, during installation and modification of the in-plant equipment, the impact on plant operation is very significant and likely would involve an extended plant outage. The plant net output would also be reduced by several effects: the extra auxiliary power required by the differential power use of the new pumps compared to the existing ones; makeup and blowdown pump power; mechanical draft cooling tower fan power, if applicable; miscellaneous small motors; and the loss in steam turbine performance due to the higher condenser backpressures resulting from the higher cooling water temperatures delivered by the tower.

This retrofit design consists of modifying the existing cooling system to encompass the cooling tower circuit, returning the cooled water to the existing intake pump bay. The existing circulating water pumps would be appreciably upgraded to allow them the head and capacity to pump the cooling water directly to the tower. The higher hydraulic pressures would necessitate increasing the existing structural integrity of the CW piping within the plant and the condenser. Approximately the same quantity of cooling water would be employed in the retrofit as in the original design. The flow from the tower back to the modified pump bay suction would be via gravity or a set of low lift pumps if required. The modified pump bay would be generously sized to avoid hydraulic instability. Higher electrical power and controls would be needed to be brought from the switchyard to the location of the pumps cooling tower pump basin. If a mechanical draft tower, the cooling fan motor control center would also need to have a set of cabling, controls and switchgear. The pump voltage would be usually 4160 while the fan motor voltage would be typically 460 and that would influence the potential location and difficulty related to identifying the proper auxiliary power sources within the existing plant.

The cooling tower makeup would be introduced into the modification of the original pump suction bay. Depending on the site auxiliary cooling system, it may first be routed through some heat exchangers in order take advantage of its cooler temperatures. This would be a separate, small intake for the makeup that is designed to be environmentally friendly by minimizing aquatic impacts by selecting a low intake velocity design and using fish-friendly measures, such as wedgewire screens and/or fish return flumes. Usually it would be in the same location as the original intake. Makeup water pumps would also be necessary. The tower blowdown would be taken from some convenient location ranging from the cooling tower cold water basin to the modified CW pump bay to minimize the temperature of that water discharged to the source body. The facility to blowdown may require another small pump station.

It would further be necessary to demolish all obsolete once-through components, materials and equipment that are no longer used such as the intake structure, bar-racks, discharge, diffusers, and piping. While some of this work could occur after the outage, most would be required to be completed during the shutdown to prevent interference with the subsequent plant operation.

Re-Optimized Retrofit Closed-cycle Cooling System Designs

A re-optimized retrofit closed-cycle cooling system design refers to making an appreciable change to the flow or design or both of the original cooling system parameters when the retrofit is installed. Otherwise its hardware elements would be the same as were previously listed. After an alteration of the design basis, it will then take the form of one or the other general categories of retrofit design that were described above.

A re-optimized closed-cycle retrofit design should be considered if:

- for reasons of increasing the turbine efficiency, it is desired to increase the original CW flow, producing a lower backpressure to compensate to some extent the adverse impact of the cooling tower on the station output and heat rate.
- the original once-through cooling system utilizes more cooling water than a large number of closely spaced cooling towers can efficiently cool
- a multi unit station has insufficient land to site cooling towers of a size that can manage the existing aggregate CW water quantity flows.
- it is determined to increase the temperature of the cooling water in order to produce more effective natural draft cooling tower draft so that their immense heights are reduced
- there is insufficient room on the plant property to properly site a typical cooling tower size
- during the design investigations the condenser is found to a poor candidate for a structural upgrade, then a modular condenser replacement could be installed that utilizes more or less flow than the original condenser.

During the retrofit project engineering, design, permitting and purchasing phase a re-optimization will be more intense and costly. Its major impact will occur during the installation at the plant however when appreciable modifications will need to occur. Likely, the condenser would be replaced with modular tube bundles of a different tube material and size and perhaps new waterboxes. Original design provisions would never have been made to accommodate the modular condenser replacement that may be required and so this activity further exacerbates the difficulty encountered in an outage.

Otherwise the installation activities during a retrofit and its components would be identical to those previously described. This kind of retrofit re-design will result, however, in very long station outages. As always the work is very site specific but several past estimates suggest the extra work could lengthen the plant outage by six months to a year. The plant net output would also still be reduced by the several effects, including the extra auxiliary power required by the differential power use of the new pumps compared to the existing ones; makeup and blowdown pump power; mechanical draft cooling tower fan power, if applicable; miscellaneous small motors; and, most importantly, the loss in steam turbine performance due to the usually higher condenser backpressures resulting from the higher cooling water temperatures delivered by the tower.

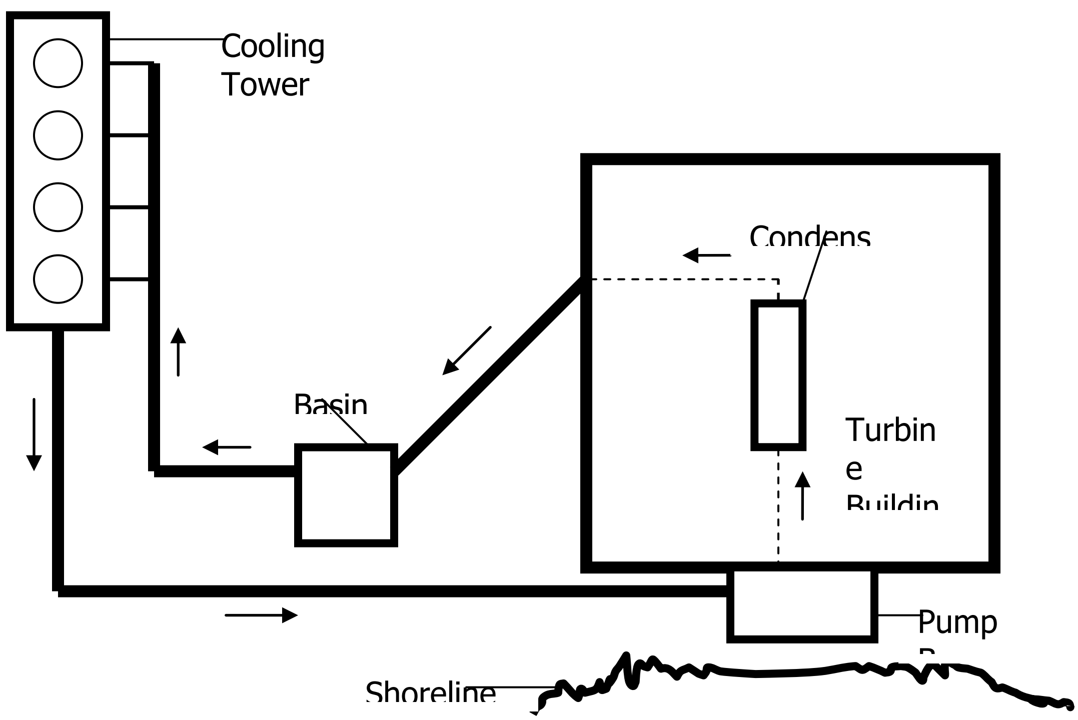


Figure 2-1
Tower on Separate Cooling Loop External to Existing Plant

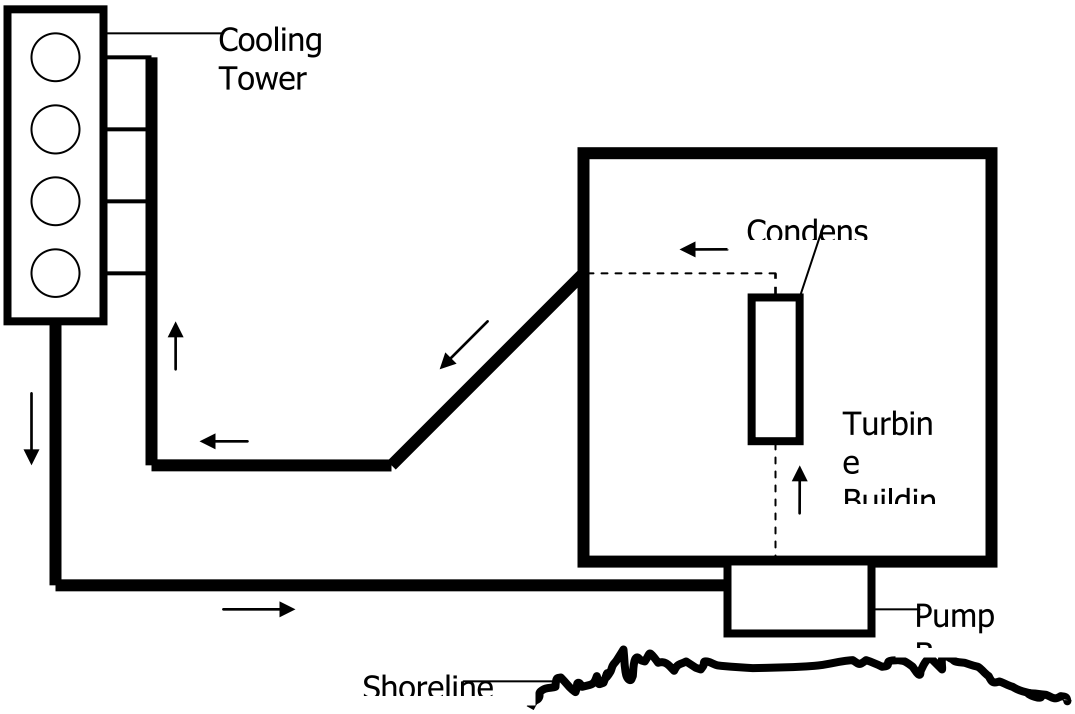


Figure 2-2
Tower on Extended Cooling Loop from Existing Plant

3
COOLING SYSTEM CUT-IN ACTIVITIES AND REQUIRED PLANT OUTAGES

In the discussion that follows, it is assumed that the retrofitted closed-cycle cooling system will only be installed for one unit of the plant. If several units are involved, the complexity, the time of the project and its outage will significantly increase for the reasons outlined in section 2

The erection of the cooling tower itself, access routes to the tower, most of the circulating water piping, the majority of the electrical components and cables can be installed from the tower back toward the plant before a plant outage. The extent would be determined by site specific conditions and the number of units involved in the closed-cycle retrofit. A large portion of the outside installation work near the station structures however may interfere with the normal operation of the plant. Depending upon the category of retrofitted closed-cycle cooling system, an even larger amount of work and a lengthy plant outage may be required within the existing station.

For each of the retrofit activities in the two following scenarios,, it is assumed the replacement component, materials, proper tooling and the equipment is on-site and that ample engineering, safety, quality control, start-up and test personnel, management and labor is available. No distinction will be made between union and non-union labor. It is further assumed that a schedule for the outage has been agreed and committed to and there is a sense of urgency to complete the work. Note that the normal outage would probably involve two 10 hour shifts daily, 6 days a week. Occasionally work could be agreed to be around the clock, 7 days a week. Sometimes, however, outage work runs only on an 8 hour daily basis, 5 days a week. Each of these particular plant outage work scenarios will naturally have an influence on the outage; i.e., the actual time it takes to completely install and test the retrofitted closed-cycle system.

The time of the activity cannot be precisely defined because of the great variety of plants, their sites, their designs, their ages and the variety of tailored retrofit closed-cycle cooling systems. The following broad discussion on the subject of the activities is organized around the major categories of Section 2.

Tower on Separate Cooling Loop External to Existing Plant

This retrofit will result in the shortest outage time because before the outage, the amount of the installation work of the components and equipment of the closed-cycle system can be maximized. The scenario presumes that:

1. The cooling tower has been constructed. This includes all related features such as basin screens, access roads, lighting, lightning and fire protection. If the installed tower was of a mechanical draft type, it is likely electrical power of the right voltage and amperage would not be available to test the fans, their motors or controls because the cables and conduits back to the transformer would not be able to be connected until the outage. Louvers on plume abated towers and other features that are operated by electrical motors or controls will have the same status. Water flow tests of the cell isolation valves, the tower bypass system, vacuum priming pumps (if applicable) and also the cell hydraulic balancing will not be able to be conducted until the water distribution circuit is linked into the fully completed closed-cycle system.
2. The large diameter buried piping that runs from the cooling tower pump basin to the towers and back to the vicinity of the existing CW pump bay will have been installed and graded over. Similarly, if this is an open channel canal in the return direction, it would also have been completed up to the area near the existing intake. During this activity, all underground and above ground yard obstructions will have been cleared and any necessary bridges or aqueducts constructed. Main CW line and bypass valves at the tower would be installed along with their motor operators. Electrical hardwire connections to the switchyard must be made, however, during the outage because the power requirements are appreciable.
3. The cooling tower pump basin would be completed along with its installed new pumps and the pumphouse structure. To minimize the number of pumps and auxiliary power, unless there were unusual circumstances, there would not be a similar pumphouse adjacent to the cooling tower basin.
4. The chemical composition and quality of the closed-cycle cooling water would not be so extreme as to require a retubing of the condenser with upgraded, more corrosion resistant tubing material along with any associated added outage time.
5. Miscellaneous structures and components to service the cooling tower such as the blowdown facility and the water treatment building including their controls and monitoring instrumentation will have been completed but not tested due to the lack of CW water.
6. All safety, confined space, radiation worker and other required site training programs for construction and other required personnel will have been completed.

Many of the activities would be accomplished in parallel with common critical path end points. For this instance, the construction, installation and demolition activity during the outage would then essentially consist of the following:

1. Shutting down the plant, safely securing and dewatering the equipment and locking out the electrical services to the power related to any associated equipment and components. Setting any necessary fire watches. Considering just the equipment cooling that must also occur, it is typical that a few days would be spent on this activity.
2. Modifying the existing pump bay suction to accommodate the cooling water return line from the towers. Note that a major amount of the retrofit outage work will be focused on the original intake area. These modifications will likely involve removing and extending a portion of the existing pump house. Since plants normally employ shore-side intakes,

the outboard section would need to be blocked from the once-through water source. This would involve enlarging the pump bay to some extent. Sheet piling could be installed as a minimum but likely rugged, large concrete retaining walls would be constructed. The extra space would be excavated as needed and dewatered. Dewatering could be a major problem since often the site and particularly the intake, is on relatively low ground next to the water body. There will be features that need to be removed or modified as the construction progresses. For example, old concrete structures for holding bar racks, pump division walls, traveling water screens, spray systems and fish protection equipment must be demolished. The new concrete walls must accommodate the cool water returns from the tower, the makeup water piping divisions that allow different pumps to be operated and controls. The existing physical pump settings, however, would not be modified in any way.

Because this is a busy, congested area during plant operation, the last few spool pieces of large diameter piping and the shut-off butterfly valve at the CW pump suction end of the line would be installed during the outage and not before. Gaskets and expansion joints would be necessary. The controls, motor operators and water treatment features of this end, related to the condenser and CW pumps, would be installed too. Fire water safety systems would be re-installed if applicable. Elevations must be carefully monitored to ensure proper flow from the cooling tower basin and to allow natural drainage from the new cooling system and its cooling tower.

At the same time, a new makeup water intake that is compliant with future CWA 316(b) requirements and contains at least two pumps will be constructed in the vicinity or at the location of the original plant intake. Its discharge line will terminate at the CW pump bay and also require a main shutoff valve. Though it may seem logical to merely use the existing intake for the makeup facility, the scale of the relative sizes precludes it. That is, the plant makeup of a closed-cycle wet cooling system is rarely 5% of the original CW flow quantity. The equipment and components are so much smaller at approximately 1/20th the size, that a new design, specifically for the makeup is needed. The makeup intake will similarly require bar racks, screens, sprays, a fish protection system, concrete retaining division walls, an ice melting system, a pump bay, electrical power panel, switchgear and controls, a small pumphouse with a means for pulling the pumps, piping, and valves.

Any underwater features that were a part of the original intake system must be demolished or they could present a danger to personnel or the public. That effort may require divers, barges and special equipment to conduct the removal. The material must be hauled away from the site and properly disposed. Depending on the waterway, coordination will be needed between the plant and the Corps of Engineers, local regulators, the state department of environmental conservation and others.

The construction in the CW pump suction/intake area must be carefully planned and executed. The preparation of detailed levels of project flow charts are essential to success in developing a schedule; multiple critical paths in this area must also be identified during the analyses, challenged and work-arounds proposed. Unforeseen difficulties and obstacles, the variety and numbers of crafts, technical personnel and engineering required to be interacting and the large construction effort confined to that small area will accentuate the complexity of the intake project. Because of this, frequent meetings up to the outage and daily meetings during the outage will be necessary to expeditiously complete the work.

3. The other major construction work location during the outage occurs near the plant's once-through cooling system discharge. Immediately outside the turbine building are the large diameter buried lines that lead from the condenser to the original once-through warm water plant discharge. These lines must be excavated at some appropriate point and diverted to the new cooling tower pump basin. Throttling valves with motor operators may be required to allow compensation in the event there is a hydraulic incompatibility between the original CW pump head and that required by the new basin target elevation. As indicated, if possible, that basin will have been constructed previous to the outage, backfilled and installed with relatively high head pumps which convey the warm condenser discharge water to the towers. The basin would be complete with a motor control center, power transformer, switchgear, a housing in a temperature controlled pump building, level controller, and spool pieces that will accommodate the large diameter piping from the condenser. Shut off valves, headers, check valves, and pump instrumentation will be included. A means for removing the pumps for repair or maintenance must be designed into the building structure and provided. Because the electrical energy requirements for the new system are substantial, all electrical hardwire connections to the switchyard must be made during the outage. Excavation of the existing line will be required; connecting, trenching, founding and bedding the new pipe from the diversion point to the new pump basin will be necessary. Underground obstructions may be encountered. The area near the waterfront is often very congested and the construction in this area must be slow and careful. The existing, unused pipe cannot be abandoned in-place since there would be a danger of its future collapse. Thus, the old pipe trench must be immediately filled, compacted and finish graded.

   For similar reasons that were discussed with respect to the intake, the plant discharge facility must be demolished and the materials hauled away. This could also involve underwater work. Besides the typical shore-side structural features of the discharge, many once-through cooling systems have diffusers located at the very end of the discharge piping that is offshore.

4. After the construction has been completed, the start-up and testing of the system components can commence. Water will be introduced into the basins. The electrical power centers at the cooling tower and the new basin will be energized and their proper operation confirmed. Fans and pumps will then be tested to ensure accurate control and operation; valves will be stroked and their motor operators engaged. The makeup system would be checked to confirm an appropriate cooling flow is delivered to the heat exchangers on that circuit such as turbine lube oil, component cooling, service water and seal water. The overall water levels of the cooling water system will be monitored. Any leaks will be found and repaired. The cooling tower cells will be hydraulically balanced. Corrections to the operation and control of all equipment and components will be made as necessary. The process must be systematic and it will be time consuming.

   Pressures and temperatures within the new closed-cycle system will be calibrated and verified. Start-up steam would be generated and the functional performance of the new closed-cooling system on the plant operation would be checked and monitored to ensure major performance or other problems will not occur. A final check on the system performance and its operation would follow. At that point a tentative full load operation could begin. The acceptance tests of the new pumps and the cooling tower would be conducted immediately during this phase and presuming no major difficulties become evident, this would constitute the end of the plant outage.

5. Not addressed above are the special requirements nuclear plants have while constructing a retrofitted closed-cycle cooling system. The time of the outage can be significantly extended because of extra safety requirements and radiation controls. Besides the much larger systems that they typically represent, provision must be made to always maintain the availability of cooling water for the safety systems. Often the safety related cooling systems are directly or physically intermingled with the main once-through cooling system of the plant. Piping and instrumentation diagrams, schematics, yard piping and plant drawings would indicate the degree of separation of the systems and also how to effectively approach the construction activity and outage tasks. In any event, depending on the degree of safety system interaction with the balance-of-plant equipment and the main cooling system, the outage duration could be easily ten times that of fossil plant of a similar size and with similar physical site features.

Tower on Extended Cooling Loop from Existing Plant

This retrofit will result in a relatively long outage time. Though it appears to be a less complex closed-cycle retrofit construction approach, it is actually more complicated because the work inside the plant itself is much greater. Prior to the outage, the installation work of the components and equipment of the closed-cycle system external to the plant will be completed but that still leaves much to be accomplished during a plant shutdown. All of the assumptions made for the "Tower on Separate Cooling Loop External to Existing Plant" apply equally to this scenario, with the exception of assumption #3 regarding the cooling tower pump basin.

As discussed in the previous category of retrofit cooling system construction, many of the activities would be accomplished in parallel with common critical path end points. All of the construction activities described above for the tower on a separate loop scenario would apply, except for #3 and changes to the pumps as described below. For the case of the extended cooling loop, the construction, installation and demolition activity during the outage would additionally consist of the following:

1. The existing pumps would be replaced by relatively high head pumps and their larger motors. They will convey the cooling water through the condenser and directly up to the hot water distribution deck of the tower. As a result, the pump settings, switchgear, controls and local power transformers will need to replaced and/or upgraded for the higher power conditions of the higher head pumps. Because the electrical energy requirements for the new system are substantial, all electrical hardwire connections to the switchyard must be made during the outage.
2. Valving and motor operators, if not rated for the higher hydraulic pressures, must be replaced and installed.
3. A major work effort will be at and near the condenser in order that the equipment and components can withstand the higher hydraulic pressures imposed by the retrofit pumps. Based on the retrofit shut off pump pressures, a structural analysis of the condenser and

related components would have been made during the design phase of the work. Likely the original once-through system was designed for a much lower siphon circuit head and the required structural modifications can be appreciable. On that basis, improvement hardware would have been designed and fabricated and would be installed during the construction phase of the shutdown. To be specific, this necessary added pressure integrity would encompass:

- The condenser waterboxes. Besides the low pressure of the typical designs, the older waterbox materials, those on saltwater and brackish water sites are often cast iron. That material has a low allowable stress and is subject to brittle failures at high pressures. Further, welding is not an effective repair option to use for attaching any structural enhancement. Only an elaborate hardware design can improve the integrity and its installation may require removal of the waterboxes. The other alternative is to design and fabricate a suitable replacement waterbox. Waterboxes can weigh up to 30,000 lbs and heavy hoist equipment may be needed to be brought in to remove them as either a replacement or to backfit an improved design. Only after an inspection and verification of the waterbox suitability can the installation begin. There are usually at least four waterboxes on each condenser and there are large bolts at a 3 inch center to center distance along the peripheral flanges and at the expansion joint beneath, so the work is extensive.
- Once-through condenser tube bundles were not designed to handle the higher hydraulic loadings of a closed-cycle cooling system. Based on a structural analysis during the retrofit design phase, customized hardware would be developed to compensate for the higher hydraulic pressures. Inside the vacuum spaces, the hardware would be extensive and necessitate attachments to the periphery of the tubesheets at a close spacing. Only after an inspection and verification of the details of the tubesheet that can be adopted, can the installation begin. Since there are normally at least two tube bundles per condenser, the work could take a lengthy period of time in a very confined space.
- One indicative example of the long extent this aspect alone of the time the work could take was a closed-cycle cooling system with a condenser that had included a design provision for reinforcement of its tube bundles due to the hydraulic pressure imposed by the cooling towers. Shortly after the plant's commercial start-up, it was discovered that this bundle reinforcement was not installed by the factory. A shut down and field installation of almost a month was required to install the needed hardware.
- The original large diameter CW piping would not have been designed with a margin sufficient to necessarily withstand the higher retrofit hydraulic pressure and sufficient corrosion resistance to the more concentrated chemicals contained in the closed-cyle cooling water. Therefore, the original piping, often buried under 10 ft of concrete, must be analyzed for compatibility with the new system. If it is found to be inadequate, a structural reinforcing design, suitable for installation in-situ, must be installed during the outage. An inspection by a licensed and experienced engineer would be first required to ensure that the condition of the existing pipe is acceptable. The pipe would then be prepared and the structural reinforcement installed until it transitioned to the new piping run, previously bedded. The mechanical enhancement would need to cover all the piping and that could be in 8 ft diameter pipe ranging from 100 to 1000s of ft in length.

- In all cases the materials of these above retrofitted components are usually steel or other material that will be subject to corrosion by the relatively concentrated quality of circulated water of the closed-cycle system. Thus, those components must be suitably coated after their installation to prevent deterioration. That work must be done slowly, carefully and safely with precise cure times, pot life criteria and specific environmental conditions. The quantity and surface area of the improvements above that must be coated, further extends the outage and complicates the construction in the turbine building.

Re-optimized Closed-cycle Cooling System Designs

In some cases, plants that are required to retrofit closed-cycle cooling may need to re-optimize their cooling system, and make a major change to its design parameters. These instances might comprise situations where there is insufficient space on the site for a cooling tower that is capable of effectively cooling the existing quantity of CW flow. A flow changing condition may also arise as a means of improving the draft of a natural draft tower if that option was selected for the retrofit tower. It may be that the regulatory need to retrofit coincides with station improvement enhancements, such as an increase in reactor power, changing out a turbine, repowering the station, the restoration of a physically deficient condenser or a design increase of CW flow to compensate for the loss in plant performance due to the retrofit. For relatively minor changes from the existing CW flow, the outage work and durations would be no different than the two general categories of conceptual retrofit cooling system design that were discussed previously. If, however, there is an appreciable change in the CW flow rate, additional major changes in the condenser and to the CW pumps would occur. These modifications would most likely employ the cooling loop extension type of conceptual retrofit design because substantial construction will occur inside the turbine building anyway.

A major change in the CW flow rate would require the condenser to be redesigned for example, to a two-pass design arrangement from a single pass unit or vice versa. Though unusual, if sufficient room under the turbine and surrounding the condenser exists, the condenser could be enlarged in major ways. In this general case, the existing condenser waterboxes or tube bundles would be replaced by modular self-contained bundles after the waterboxes and existing tube bundles are removed. No other type of replacement such as rebuilding the condenser internals in-situ and tubing it tube-by-tube, would be practical. A project that designs, has fabricated and installs the modular bundles alone is a very expensive undertaking and usually requires a lengthy outage to complete the installation. While the former engineering actions are not within the scope of study, the effort of their change-out installation and construction is, when incorporated into a closed-cycle cooling system retrofit project.

In addition to all the construction and demolition that was presented previously for the extended cooling loop category of retrofit it would be necessary to:

- Remove all interferences between the access to the turbine building and at least one end of the condenser. Because a condenser was always considered to be permanently installed, unlike a retubing, typically there is no provision for moving a large tube bundle module, possibly 15ft by 15ft by 40 ft long, from the outside into the condenser space under the turbine. Removal of the interferences could be extensive and include block walls, equipment rooms, heat exchangers, transformers, piping, and tanks.

- Remove the waterboxes; store or haul them away from the site.
- Brace the shells and provide support for any heaters or piping within the steam space. Take out the existing tube bundles or the tubes individually. Torch the many welds and remove the internal bundle support plates from the shell walls and hotwell. Clean up all debris.
- Move the new tube bundles into the condenser, weld attach the supports and the closure end plates.
- Remove all temporary bracing. Install the waterboxes with its gaskets, instrumentation, anodes, drain, vent, priming system and accumulator connections.
- Replace all interferences.

In all other respects, the closed-cycle retrofit construction work is the same as has been described.

The total time of a station outage when the cooling system is also resized however, will increase substantially by the added work outlined above.

4
REFERENCES

J. H. Keenan, Thermodynamics, John Wiley & Sons, N.Y., 1941.

RS Means, Heavy Construction Cost Works, Norwell, MA, 2011.

Burns, J. M., Burns, D.C., Burns J. S.; “Estimates Required to Achieve the Next Level of CWA 316(b) Compliance”, presented at the International Joint Power Generation Conference, Electric Power, March 2004.

Burns, J.M.; Nicholson, J.M.; Annett, J.H.; and Alexander, D.N.; "The Impacts of Retrofitting Cooling Towers at a Large Power Station.” EPRI Cooling Tower Conference, August 1994.

Export Control Restrictions

Access to and use of EPRI Intellectual Property is granted with the specific understanding and requirement that responsibility for ensuring full compliance with all applicable U.S. and foreign export laws and regulations is being undertaken by you and your company. This includes an obligation to ensure that any individual receiving access hereunder who is not a U.S. citizen or permanent U.S. resident is permitted access under applicable U.S. and foreign export laws and regulations. In the event you are uncertain whether you or your company may lawfully obtain access to this EPRI Intellectual Property, you acknowledge that it is your obligation to consult with your company's legal counsel to determine whether this access is lawful. Although EPRI may make available on a case-by-case basis an informal assessment of the applicable U.S. export classification for specific EPRI Intellectual Property, you and your company acknowledge that this assessment is solely for informational purposes and not for reliance purposes. You and your company acknowledge that it is still the obligation of you and your company to make your own assessment of the applicable U.S. export classification and ensure compliance accordingly. You and your company understand and acknowledge your obligations to make a prompt report to EPRI and the appropriate authorities regarding any access to or use of EPRI Intellectual Property hereunder that may be in violation of applicable U.S. or foreign export laws or regulations.

The Electric Power Research Institute Inc., (EPRI, www.epri.com) conducts research and development relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, health, safety and the environment. EPRI also provides technology, policy and economic analyses to drive long-range research and development planning, and supports research in emerging technologies. EPRI's members represent more than 90 percent of the electricity generated and delivered in the United States, and international participation extends to 40 countries. EPRI's principal offices and laboratories are located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass.

Together...Shaping the Future of Electricity

Program:

Fish Protection at Steam Electric Power Plants

1023453

Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com