Gulf Power

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August 24, 2018

Ms. Carlotta Stauffer, Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

RE: Docket No. 20180007-EI

Dear Ms. Stauffer:

Attached for official filing in the above-referenced docket are the following:

1. The Petition of Gulf Power Company.

2. Prepared direct testimony and exhibits of Richard M. Markey.

3. Prepared direct testimony and exhibit of C. Shane Boyett.

Pursuant to the Order Establishing Procedure in this docket, electronic copies of exhibits CSB-3, RMM-1 and RMM-2 will be provided to the parties under separate cover.

Sincerely,

Rhonda J Alexander

Rhonda J. Alexander
Regulatory, Forecasting and Pricing Manager

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Attachments

cc w/att.: Florida Public Service Commission
  Charles Murphy, Sr. Attorney, Ofc of the General Counsel (5 copies)
Gulf Power Company
  Jeffrey A. Stone, Esq., General Counsel
Beggs & Lane
  Russell Badders, Esq.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: Environmental Cost Recovery Clause	)	
	)	Docket No.: 20180007-EI
	)	Filed: August 24, 2018
	)	

PETITION OF GULF POWER COMPANY FOR APPROVAL OF FINAL ENVIRONMENTAL COST RECOVERY TRUE-UP AMOUNT FOR JANUARY 2017 THROUGH DECEMBER 2017; ESTIMATED ENVIRONMENTAL COST RECOVERY TRUE-UP AMOUNT FOR JANUARY 2018 THROUGH DECEMBER 2018; PROJECTED ENVIRONMENTAL COST RECOVERY AMOUNTS FOR JANUARY 2019 THROUGH DECEMBER 2019; NEW ENVIRONMENTAL ACTIVITIES/PROJECTS; AND ENVIRONMENTAL COST RECOVERY FACTORS TO BE APPLIED BEGINNING WITH THE PERIOD JANUARY 2019 THROUGH DECEMBER 2019

Notices and communications with respect to this petition and docket should be addressed to:

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GULF POWER COMPANY ("Gulf Power", "Gulf", or "the Company"), by and through its undersigned counsel, and pursuant to section 366.8255, Florida Statutes and various orders of the Florida Public Service Commission ("Commission") implementing and defining the Environmental Cost Recovery Clause ("ECRC"), hereby petitions the Commission for approval of the Company's final environmental cost recovery true-up amount for the period January 2017 through December 2017; for approval of the Company's estimated environmental cost recovery true-up amount for the period January 2018 through December 2018; for approval of the

Company's projected environmental cost recovery amounts for the period January 2019 through December 2019; for approval of new and/or expansions of other environmental projects consistent with this petition; and for approval of environmental cost recovery factors to be applied in customer billings beginning with the period January 2019 through December 2019. As grounds for the relief requested by this petition, the Company would respectfully show:

BACKGROUND

(1) Section 366.8255, Florida Statutes, (the "Statute") authorizes the Commission to review and decide whether Gulf's environmental compliance costs are recoverable through an environmental cost recovery factor. Pursuant to the Statute, environmental compliance costs include "[a]ll costs or expenses incurred by an electric utility in complying with environmental laws or regulations. . . ." The term "environmental laws or regulations" is defined in the Statute to include "all federal, state, or local statutes, administrative regulations, orders, ordinances, resolutions, or other requirements that apply to electric utilities and are designed to protect the environment." Pursuant to the Statute, the Commission shall allow a utility to recover its prudently incurred environmental compliance costs through the ECRC which is separate and apart from the utility's base rates. Only prudently incurred environmental compliance costs may be recovered through the ECRC. In Order No. PSC-94-0044-FOF-EI, issued January 12, 1994, the Commission identified three criteria for eligibility for cost recovery through the ECRC: 1) the costs must have been incurred after April 13, 1993; 2) the activity is legally required to comply with a governmentally imposed environmental regulation which was enacted, or became effective, or whose effect was triggered after the company's last test year upon which rates are based; and, 3) the costs are not recovered through some other cost recovery mechanism or through base rates.

(2) Gulf Power initially petitioned the Commission to establish the ECRC in Docket No. 930613-EI. The Commission considered Gulf's petition at hearings held in December 1993 and ultimately issued Order No. PSC-94-0044-FOF-EI which established the ECRC for Gulf Power and approved the commencement of recovery through initial factors effective with the first billing cycle for February 1994. Since that initial order, Gulf has periodically petitioned for and received Commission approval for recovery of the Company's revenue requirements associated with new environmental compliance activities consistent with the ECRC statutes and Commission precedent. Also since that initial order and subsequent orders of the Commission approving the Company's environmental compliance activities for recovery through the ECRC, Gulf has periodically submitted true-up and projection filings to the Commission with updated actual and projected costs for the various environmental compliance activities recovered through the ECRC pursuant to Commission authorization.

(3) Consistent with the foregoing, Gulf submits its petition, supporting schedules, testimony and exhibits as the Company's request herein for approval of ECRC factors to be effective in calendar year 2019. As detailed in the following paragraphs and accompanying supporting schedules, testimony and exhibits, Gulf's environmental compliance activities are consistent with the ECRC statutes and Commission precedent for recovery of eligible activities through the ECRC subject to the ongoing audit, review and true-up processes established by the Commission.

FINAL ENVIRONMENTAL COST RECOVERY TRUE-UP AMOUNTS

(4) By vote of the Commission following hearings in October 2017, estimated true-up environmental cost recovery amounts were approved by the Commission for the period January 2017 through December 2017, subject to establishing the final environmental cost recovery

true-up amounts. Gulf has calculated its final environmental cost recovery true-up amounts for the period January 2017 through December 2017 in accordance with the principles and policies for environmental cost recovery established by the Commission. According to the data filed by Gulf for the period ending December 31, 2017, the final environmental cost recovery true-up amount for the period ending December 31, 2017, is an actual over-recovery of $3,179,666. This amount is submitted for approval by the Commission to be applied in the next period. The supporting data has been prepared in accordance with the uniform system of accounts as applicable to the Company's environmental cost recovery and fairly presents the Company's environmental costs to be considered for recovery through the ECRC for the period. The environmental activities and related expenditures reflected in the true-up amounts shown for the period ending December 31, 2017, are reasonable and necessary to achieve or maintain compliance with environmental requirements applicable to Gulf Power Company and, therefore, the amounts identified are prudent expenditures which have been incurred for utility purposes.

<u>ESTIMATED ENVIRONMENTAL COST RECOVERY TRUE-UP AMOUNTS</u>

(5) Gulf has calculated its estimated environmental cost recovery true-up amounts for the period January 2018 through December 2018 in accordance with the principles and policies for environmental cost recovery established by the Commission. Based on six months actual and six months projected data, the Company's estimated environmental cost recovery true-up amount for the period January 2018 through December 2018 is an over-recovery of $9,436,937. The estimated environmental cost recovery true-up is combined with the final environmental cost recovery true-up for the period ending December 31, 2017, to reach the total environmental cost recovery true-up that is to be addressed in the next cost recovery period (January 2019 through

December 2019). Gulf is requesting that the Commission approve this total environmental cost recovery true-up amount excluding revenue taxes, of $12,616,603 to be applied during the January 2019 through December 2019 recovery period.

PROJECTED ENVIRONMENTAL COST RECOVERY AMOUNTS

(6) Gulf has calculated its projected environmental cost recovery amounts for the months January 2019 through December 2019 in accordance with the principles and policies for environmental cost recovery found in section 366.8255 of the Florida Statutes and Commission Order No. PSC-94-0044-FOF-EI. The calculated factors reflect the recovery of the projected environmental cost recovery amount of $171,663,438 for the period January 2019 through December 2019, less the net true-up amount adjusted for revenue taxes.

The computations and supporting data for the Company's environmental cost recovery factors are set forth on true-up and projection schedules that are attached as part of the exhibits to the final true-up testimony and estimated/actual true-up testimony of C.S. Boyett filed previously in this docket (*See* DN 02660-2018 and DN 04874-2018) and the projection testimony of Mr. Boyett filed herewith. Additional supporting data for the environmental cost recovery factors is provided in the final true-up testimony of R. M. Markey (*See* DN 02660-2018), the estimated/actual true-up testimony of Mr. Markey (*See* DN 04874-2018) and the projection testimony of Mr. Markey filed herewith. The methodology used by Gulf in determining the amounts to include in these factors and the allocation to rate classes is in accordance with the requirements of the Commission as set forth in Order Nos. PSC-94-0044-FOF-EI and PSC-13-0606-FOF-EI. The amounts included in the calculated factors for the projection period are based on reasonable projections of the costs for environmental compliance activities that are expected to be incurred during the period January 2019 through December 2019. The calculated factors and supporting data have been prepared in accordance with the uniform system of accounts and fairly present the Company's best estimate of environmental compliance costs for the projected period. The activities described in the testimony of Mr. Markey are reasonable and necessary to achieve or maintain compliance with environmental requirements applicable to Gulf Power Company and the actual or projected costs resulting from the described compliance activities are also reasonable and necessary. Therefore, the costs identified are prudent expenditures that have been or will be incurred for utility purposes and for which the Company should be allowed to recover the associated revenue requirements.

NEW ENVIRONMENTAL ACTIVITIES/PROJECTS

(7) Gulf seeks approval of the 316(b) Cooling Water Intake Structure Regulation ("316(b)") Project for cost recovery through the Environmental Cost Recovery Clause. The 316(b) Project addresses costs associated with Gulf's compliance with new requirements of the Federal Clean Water Act, specifically section 316(b) Cooling Water Intake Structure Regulation. On August 15, 2014, the Environmental Protection Agency (EPA) published final regulations under Section 316(b) of the Clean Water Act for cooling water intake structures at existing electric generating facilities. The rule became effective on October 14, 2014, requiring existing facilities withdrawing greater than 2 million gallons per day (MGD) to adopt one of seven options for addressing impingement at the entrance to existing cooling water intake structures. In FPSC Order No. PSC-04-1187-FOF-EI, the Commission approved Gulf's request to recover prudently incurred 316(b) biological sampling and data collection through the ECRC. These studies were needed by Gulf to determine which of the seven options would be the most

appropriate, cost-effective method for meeting the new 316(b) requirements for its existing plants. In 2019, Gulf expects to incur compliance costs for 316(b) activities at its Plant Smith facility. The Plant Smith industrial wastewater permit requires Gulf to submit information required under the Cooling Water Intake Structure 316(b) rule with its next permit renewal filing in April 2019. While Gulf's 316(b) compliance strategy and design ultimately must be approved by the Florida Department of Environmental Protection in the permit renewal process, Gulf Power's preliminary studies indicate Plant Smith will need to install new lower capacity intake pumps and a closed-cycle cooling tower monitoring system for the existing Unit 3 closed-cycle cooling tower. The lower capacity pumps are needed to reduce the intake maximum through-screen velocity to less than 0.5 foot per second to meet the 316(b) impingement performance standard. Gulf plans to install the new lower capacity intake pumps at Plant Smith during 2019 to meet compliance deadlines.

The 316(b) project meets the criteria for cost recovery established by the Commission in Order No. PSC-94-0044-FOF-EI in that the costs associated with it are not recovered through any other cost recovery mechanism or through base rates and will be incurred after April 13, 1993. In addition, Gulf's compliance with the new 316(b) regulations and associated permit conditions is legally mandated under a governmentally-imposed environmental regulation. The capital expenditures associated with this project are projected to be $2,000,000 in 2019. During 2019, Gulf projects a total of $160,000 in O&M expenses for 316(b) compliance activities. Capital costs for the 316(b) project should be allocated to the rate classes on an average 12-MCP demand and 1/13th energy basis. O&M cost for the program should be allocated to the rate classes on a demand basis.

ENVIRONMENTAL COST RECOVERY FACTORS

(8) The calculated environmental cost recovery factors by rate class, including true-up, are:

RATE CLASS	ENVIRONMENTAL COST RECOVERY FACTORS ¢/kWh
RS, RSVP, RSTOU	1.810
GS	1.669
GSD, GSDT, GSTOU	1.483
LP, LPT	1.327
PX, PXT, RTP, SBS	1.272
OS-I/II	0.511
OS-III	1.172

WHEREFORE, Gulf Power Company respectfully requests the Commission to approve the final environmental cost recovery true-up amounts for the period January 2017 through December 2017; estimated environmental cost recovery true-up amounts for the period January 2018 through December 2018; the projected environmental cost recovery amounts for the period January 2019 through December 2019; the reasonableness and prudence of new and/or expansions of other environmental projects consistent with this petition; and the environmental cost recovery factors to be applied in customer billings beginning with the period January 2019 through December 2019.

Dated the 24th day of August 2018.

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

ENVIRONMENTAL COST RECOVERY CLAUSE

DOCKET NO. 20180007-EI

PREPARED DIRECT TESTIMONY
AND EXHIBITS OF
RICHARD M. MARKEY

PROJECTION FILING
FOR THE PERIOD

JANUARY 2019- DECEMBER 2019

August 24, 2018

Gulf Power

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Richard M. Markey
Docket No. 20180007-EI
Date of Filing: August 24, 2018

Q. Please state your name, business address, and occupation.

A. My name is Richard M. Markey. My business address is One Energy Place, Pensacola, Florida, 32520. I am employed by Gulf Power Company as the Director of Environmental Affairs.

Q. Have you previously filed testimony in this docket?

A. Yes, I have.

Q. Mr. Markey, what is the purpose of your testimony?

A. The purpose of my testimony is to support Gulf Power Company's projection of environmental compliance costs recoverable through the Environmental Cost Recovery Clause (ECRC) for the period from January 2019 through December 2019.

Q. Have you prepared any exhibits that contain information to which you will refer in your testimony?

A. Yes, I have prepared two exhibits. The first exhibit (RMM-1) includes Schedule 5P - Description and Progress Report of Environmental Compliance Activities and Projects. The second exhibit (RMM-2) includes the 316(b) Cooling Water Intake Structure Regulation.

Counsel: We ask that Mr. Markey's exhibits be marked as Exhibit No. _____ (RMM-1) and Exhibit No. _____ (RMM-2).

CAPITAL

Q. Mr. Markey, please identify the capital projects included in Gulf's ECRC projection filing.

A. The environmental capital projects for which Gulf seeks recovery through the ECRC are listed in Schedules 3P and 4P of Gulf Witness Boyett's Exhibit CSB-3 and described in Schedule 5P included in my Exhibit RMM-1. I am supporting the expenditures, clearings, retirements, salvage and cost of removal currently projected for each of these projects. Mr. Boyett compiled these schedules and has calculated the associated revenue requirements for Gulf's requested recovery. Of the projects shown on Mr. Boyett's schedules, one is a new program that Gulf is proposing and nine programs were previously approved by the Commission which have activities with projected capital expenditures during 2019. These programs include: Air Quality Assurance Testing, Continuous Emission Monitoring Systems (CEMS), Substation Contamination Remediation, Smith Water Conservation, Crist Florida Department of Environmental Protection (FDEP) Agreement for Ozone Compliance, Crist Water Conservation, Air Quality Compliance Program, Coal Combustion Residuals, and Effluent Limitations Guidelines.

Q. Mr. Markey, please describe the new capital program Gulf seeks to recover through the ECRC.

A. Gulf is including one new Water Quality program, the 316(b) Cooling Water Intake Structure project, in addition to the programs previously approved by the Commission.

Q. Mr. Markey, please describe the 316(b) Cooling Water Intake Structure program that Gulf seeks to recover through the ECRC (Line Item 1.30).

A. On August 15, 2014, the EPA published final regulations under Section 316(b) of the Clean Water Act for cooling water intake structures at existing electric generating facilities. The rule, found in Title 40 Parts 122 and 125 of the Code of Federal Regulations, (See Exhibit RMM-2), became effective on October 14, 2014, requiring existing facilities withdrawing greater than 2 million gallons per day (MGD) to adopt one of seven options for addressing impingement at the entrance to existing cooling water intake structures.

Although the ultimate 316(b) compliance strategy and design will be approved by the state environmental permitting agencies, with possible input from the U.S. Fish and Wildlife Service and National Marine Fisheries Service (Services) and EPA, Gulf Power's preliminary studies indicate Plant Smith will need to install new lower capacity intake pumps and a closed-cycle cooling tower monitoring system for the existing Unit 3 closed-cycle cooling tower.

The lower capacity pumps are needed to reduce the intake maximum through-screen velocity to less than 0.5 foot per second to meet the 316(b) impingement performance standard. Gulf plans to install the new lower capacity intake pumps at Plant Smith during 2019. The Plant Smith industrial wastewater permit requires Gulf to submit information required under the Cooling Water Intake Structure 316(b) rule with its next permit renewal, due in April 2019 for FDEP review and approval. The projected 2019 expenditures for this line item total $2,000,000.

Q. Mr. Markey, please describe the projected 2019 capital expenditures for Air Quality Assurance Testing (Line Item 1.1).

A. Gulf plans to replace the existing analyzers located in the Gulf Power test trailer during 2019. The existing analyzers are used for Relative Accuracy Test Audits (RATAs) and other testing at various Gulf locations. The analyzers are at the end of the normal useful life, and the manufacturer no longer provides spare parts. Expenditures associated with this equipment reflected in the 2019 projection filing are $65,000.

Q. Mr. Markey, please describe the projected 2019 capital expenditures for Continuous Emission Monitoring Systems (CEMS) (Line Item 1.5).

A. Gulf plans to replace the existing Plant Crist CEMS monitors located in the scrubber stack during 2019. The existing monitors are at the end of the normal life cycle and need to be replaced. Expenditures associated with these activities reflected in the 2019 projection filing are $200,000.

Q. Mr. Markey, please describe the projected 2019 capital expenditures for Substation Contamination Remediation (Line Item 1.6).

A. During 2019, Gulf plans to complete construction of the Fort Walton and Wewa substation remediation systems. The existing remediation equipment at the Fort Walton substation was installed in 1998 and needs to be replaced. Gulf is currently in the process of designing an active remediation system for the Wewa substation site. Site geological and geochemical data indicate installing a permeable reactive barrier (PRB) is the best option to decrease groundwater concentrations at the Wewa site. Expenditures associated with these activities reflected in the 2019 projection filing total $1,496,496.

Q. Mr. Markey, please provide an update on the Smith Water Conservation program (Line Item 1.17).

A. Gulf was granted approval for ECRC recovery of the Plant Smith Reclaimed Water project in Florida Public Service Commission (FPSC) Order No. PSC-09-0759-FOF-EI. Gulf has installed three deep injection wells, piping, and initial equipment needed for the reclaimed water pump station. Design and construction of the Underground Injection Control (UIC) wastewater treatment system and associated pump station were postponed in 2018 due to delays in the Request for Qualifications (RFQ) process for the reclaimed water pipeline design for the piping between Bay County and Plant Smith. Gulf plans to complete design and begin construction of the system needed for reclaimed water in 2019. Expenditures associated with these activities reflected in the 2019 projection filing are $13,033,532.

While Gulf is in the process of completing design and construction of the reclaimed water system, the Smith UIC system will be used for treatment and injection of wastewater from the Plant Smith ash pond closure project.

Q. Mr. Markey, please describe the projects included in the 2019 projection for the Crist FDEP Agreement for Ozone Attainment (Line Item 1.19).

A. Gulf plans to replace catalyst in the Plant Crist Unit 7 SCR during 2020. The catalyst NOx removal effectiveness is declining at a normal rate and indicates the catalyst will need to be replaced during a 2020 outage. The projected 2019 expenditure is for a catalyst progress payment totaling $200,000.

Q. Please describe the projected capital expenditures for the Crist Water Conservation program (Line Item 1.24).

A. The Crist Water Conservation program is part of Gulf's water conservation and consumptive use efficiency program required by the Plant Crist consumptive water use permit. Plant Crist's consumptive use permit, issued by the Northwest Florida Water Management District (NWFWMD), requires the plant to implement measures to increase water conservation and efficiency at the facility. The 2019 projected expenditures for the Crist Water Conservation program are for the replacement of pumps, valves and motors. The projected 2019 expenditures for this line item total $100,000.

Q. Please describe the projected capital expenditures for the Air Quality Compliance program (Line Item 1.26).

A. The 2019 projected expenditures for the Air Quality Compliance program include costs associated with the following: Plant Crist and Plant Daniel scrubbers, Plant Crist Unit 6 SCR, and the Plant Daniel Low NOx burners. More specifically, this line item includes expenditures for the Plant Crist gypsum storage area, gas cooling nozzles, scrubber agitator gear box, Unit 6 SCR catalyst layer, elevator, and air compressors. Approximately $6.2 million is projected for expansion of the Plant Crist UIC pump station. The expansion will allow Plant Crist to utilize two additional wells for disposal of wastewater generated from the gypsum storage facility and associated groundwater remediation system. Plant Crist will also be constructing a new limestone system that will add limestone as needed to the coal to help maintain the performance of catalyst used in the SCRs. The cost of the new limestone system is projected to be approximately $1 million. During 2019, Gulf will be making a progress payment of $500,000 for a new scrubber alignment grid at Plant Crist that will be installed in the 2020 scrubber outage. Plant Daniel will also be replacing the low NOx burners on Unit 2, which have reached the end of their useful life. The cost of the new low NOx burners is approximately $490,000. The projected 2019 expenditures for this program total $8,660,145.

Q. Mr. Markey, please describe the projects included in Gulf's 2019 projection for the Coal Combustion Residuals capital program (Line Item 1.28).

A. Line Item 1.28 is related to the regulation of Coal Combustion Residuals (CCR) by the United States Environmental Protection Agency (EPA) and FDEP. For Gulf's generating plants, these regulatory compliance obligations are pursuant either to the CCR rule adopted in April 2015 or through new requirements added by FDEP to the National Pollutant Discharge Elimination System (NPDES) permits issued for each of Gulf's Florida generating facilities pursuant to authority granted under the Clean Water Act. The CCR rule is located in Title 40 Code of Federal Regulations (CFR) Parts 257 and 261. Plant Scherer is also regulated under Georgia's Environmental Protection Division CCR Rule (391-3-4-.10), which requires permit applications to be submitted for the facility's ash pond and CCR landfill by November 22, 2019. The projected 2019 expenditures for this line item total $50.8 million, which includes costs for Plants Scholz, Smith, Scherer and Daniel as discussed below.

Construction activities for closure of the ash pond at Plant Scholz have begun. During 2019, the Scholz ash pond closure project will include constructing a new stormwater management system, transferring CCR material to a dry stack area within the footprint of the pond, and capping the dry stack area with closure turf material. The 2019 expenditures for the Plant Scholz CCR closure are projected to be $7.1 million.

Earlier this year at Plant Smith, Gulf began construction of a new industrial wastewater treatment pond by relocating CCR material within the ash pond footprint. In 2019, Gulf will proceed with constructing new industrial wastewater ponds and a slurry wall, as well as transferring CCR material to a dry stack area within the footprint of the pond. The 2019 expenditures for the Plant Smith CCR closure are projected to be $22.5 million.

The Plant Scherer ash pond is scheduled to stop receiving coal ash in 2019. Engineering and construction work necessary to accommodate dry ash handling is expected to be completed in 2019. Design and construction of the Scherer CCR wastewater management system will continue in 2019. In addition, detailed engineering and construction will continue at Cell 3 of the onsite landfill for CCR storage. Plant Scherer will also proceed with siting studies and preliminary design for a new landfill. The 2019 expenditures for the Plant Scherer CCR projects are projected to be $9.2 million.

The Plant Daniel bottom ash pond closure is projected to begin in the 2021 timeframe and is expected to take approximately three years to complete. Prior to beginning closure activities, the plant will need to construct a new wastewater treatment and ash handling system. Plant Daniel is currently in the process of completing studies to determine the most cost-effective technologies and system design. Plant Daniel will need to reroute wastewater streams from the ash pond to a new wastewater system prior to beginning closure of the bottom ash pond in 2021. The 2019 expenditures for the Plant Daniel CCR projects are projected to be $12.0 million.

Q. Mr. Markey, please describe the projects included in Gulf's 2019 projection for the Effluent Limitations Guideline capital program (Line Item 1.29).

A. In 2015, the EPA finalized revisions to the steam electric effluent limitations guidelines (ELG) rule, which imposes stringent technology-based requirements for certain waste streams from steam electric generating units. The revised technology-based limits and compliance dates will require extensive modifications to existing ash and flue gas desulfurization (FGD) scrubber wastewater management systems or the installation and operation of new wastewater management systems. Compliance applicability dates in the 2015 rule ranged from November 1, 2018, to December 31, 2023.

On September 18, 2017, EPA published a final rule in the Federal Register that delayed the earliest ELG applicability date for FGD wastewater and bottom ash transport water from the original (2015 rule) "as soon as possible date" of November 1, 2018, to a new "as soon as possible" date of November 1, 2020, to allow time for EPA to reconsider the requirements for FGD wastewater and bottom ash transport water. The 2017 rule did not change the latest applicability date or "no later than" date of December 31, 2023.

State environmental agencies will incorporate specific applicability dates in the NPDES permitting process based on information provided for each waste stream. The EPA plans to propose ELG rule revisions in December 2018 and to finalize the rulemaking in December 2019. Gulf has projected costs in 2019 for engineering and design of Gulf's ownership portion of the

Scherer scrubber wastewater treatment system. The 2019 expenditures for this line item total $456,695.

Operation and Maintenance (O&M)

Q. How do the projected Environmental O&M activities listed on Schedule 2P of Mr. Boyett's Exhibit CSB-3 compare to the O&M activities approved for cost recovery in past ECRC proceedings?

A. All of the O&M programs listed on Schedule 2P have been approved for recovery through the ECRC in past proceedings.

Q. Please describe the O&M activities included in the air quality category for 2019.

A. There are five O&M activities included in the air quality category that have projected expenses in 2019. The five activities are: Air Emission Fees, Title V, Asbestos Fee, Emissions Monitoring, and the FDEP NOx Reduction Agreement.

On Schedule 2P, Air Emission Fees (Line Item 1.2), represents the expenses projected for the annual fees required by the Clean Air Act Amendments (CAAA) of 1990, also known as Title V fees, that are payable to the FDEP, the Mississippi Department of Environmental Quality, and the Georgia Environmental Protection Division. The total 2019 estimated expenses for the Air Emission Fees are $305,099.

Included in the air quality category, Title V (Line Item 1.3) represents projected ongoing expenses associated with implementation of the Title V permits. The total 2019 estimated expenses for the Title V program are $293,254.

On Schedule 2P, Asbestos Fees (Line Item 1.4) consists of the fees required to be paid to the FDEP for asbestos abatement projects. The total 2019 estimated expenses for the Asbestos Fees are $1,000.

Emission Monitoring (Line Item 1.5) on Schedule 2P reflects an ongoing O&M expense associated with the CEMS equipment as required by the CAAA. These expenses are incurred in response to EPA's requirements that the Company perform Quality Assurance/Quality Control (QA/QC) testing for the CEMS, including Relative Accuracy Test Audits (RATAs) and Linearity Tests. The total 2019 estimated expenses for the Emissions Monitoring are $739,036.

The FDEP NOx Reduction Agreement (Line Item 1.19) is comprised of O&M costs associated with the Plant Crist Unit 7 SCR and the Plant Crist Units 4 and 5 Selective Non-Catalytic Reduction (SNCR) projects that were included as part of the 2002 agreement with FDEP for ozone attainment. This line item includes the cost of anhydrous ammonia, urea, air monitoring, and general O&M expenses related to activities undertaken in connection with the agreement. Gulf was granted approval for recovery of the costs incurred to complete these activities in FPSC Order No. PSC-02-1396-PAA-

EI in Docket No. 020943-EI. The total 2019 estimated expenses for the FDEP NOx Reduction Agreement are $1,021,274.

Q. What O&M activities are included in the water quality category?

A. General Water Quality (Line Item 1.6), identified in Schedule 2P, includes costs associated with NPDES industrial wastewater permit compliance, Groundwater Monitoring and Assessment, Surface Water Studies, the Cooling Water Intake Program, Soil Contamination Studies, Dechlorination, the Impoundment Integrity Program, and Stormwater Maintenance. The total 2019 estimated expenses for General Water Quality are $2,014,654.

Q. What other O&M activities are included in the water quality category?

A. Groundwater Contamination Investigation (Line Item 1.7) was previously approved for environmental cost recovery in FPSC Docket No. 930613-EI. This line item includes expenses related to substation investigation and remediation activities. Gulf has projected $2,825,274 of incremental expenses for this line item during the 2019 recovery period.

Line Item 1.8, State NPDES Administration, was previously approved for recovery in the ECRC and reflects expenses associated with NPDES annual fees and permit renewal fees for Gulf’s three generating facilities in Florida. These expenses are expected to be $42,000 during the projected recovery period.

Line Item 1.9, Lead and Copper Rule, was also previously approved for ECRC recovery and reflects sampling, analytical, and chemical costs related to the lead and copper drinking water quality standards. These expenses are estimated to be $4,000 during the 2019 projection period. Line Item 1.23, is the CCR program that includes expenses related to the regulation of Coal Combustion Residuals by the EPA and the FDEP. During 2019, the Plant Scholz and Plant Smith CCR closure projects will be under construction, and Gulf will continue its ongoing CCR groundwater monitoring and engineering inspections. The 2019 expenses projected for the CCR line item total $3,229,639, which encompasses Plant Scholz and Plant Smith pond closure activities.

As mentioned previously, construction activities for closure of the ash pond at Plant Scholz have begun. During 2019, the Scholz ash pond closure project will include constructing a new stormwater management system, transferring CCR material upland to a dry stack area within the footprint of the pond, and capping the dry stack area with closure turf material. The 2019 expenses for the Plant Scholz CCR closure are projected to be $1.5 million.

Earlier this year at Plant Smith, Gulf began construction of a new industrial wastewater treatment pond by relocating CCR material within the ash pond footprint. In 2019, Gulf will proceed with construction and associated activities to close a portion of the pond. The 2019 pond closure activities will include constructing industrial wastewater ponds and a slurry wall, as well as transferring CCR material upland to a dry stack area within the footprint of the pond. The 2019 expenses associated with the Plant Smith CCR closure are projected to be $1 million.

Q. What activities are included in the environmental affairs administration category?

A. Only one O&M activity is included in this category on Schedule 2P (Line Item 1.10) of Mr. Boyett's Exhibit CSB-3. This line item refers to the Company's Environmental Audit/Assessment function. This program is an on-going compliance activity previously approved for ECRC recovery. The total 2019 estimated expenses for the Environmental Audit/Assessment are $15,000.

Q. What O&M activities are included in the General Solid and Hazardous Waste category?

A. The General Solid and Hazardous Waste activity (Line Item 1.11) involves the proper identification, handling, storage, transportation, and disposal of solid and hazardous wastes as required by federal and state regulations. The program includes expenses for Gulf's generating and power delivery facilities. The total 2019 estimated expenses for the General Solid and Hazardous Waste activity is $1 million.

Q. Are there any other O&M activities that have been approved for recovery that have projected expenses?

A. There are six other O&M activities that have been approved in past proceedings which have projected expenses during 2019. They are the Above Ground Storage Tanks program, the Sodium Injection System, the Air Quality Compliance Program, Crist Water Conservation, Smith Water Conservation, and Emission Allowances.

Q. What O&M activities are included in the Above Ground Storage Tanks line item?

A. Above Ground Storage Tanks (Line Item 1.12) includes maintenance activities, tank integrity inspections, and fees required by Florida's above ground storage tank regulation, Chapter 62 Part 762, F.A.C. Expenses totaling $92,532 are projected to be incurred during 2019.

Q. What activity is included in the Sodium Injection line item?

A. The Sodium Injection System (Line Item 1.16) was originally approved for inclusion in the ECRC in Order No. PSC-99-1954-PAA-EI. The activities in this line item involve sodium injection to the coal supply that enhances precipitator efficiencies when burning certain low sulfur coals at Plant Crist. Expenses totaling $10,000 are projected to be incurred during 2019 for this line item.

Q. What activities are included in the Air Quality Compliance Program (Line Item 1.20)?

A. This line item encompasses O&M expenses associated with the capital projects approved for ECRC recovery under the Air Quality Compliance Program and expenses associated with Gulf's ownership portion of the Scherer 3 baghouse, SCR, and scrubber as well as associated equipment. Anhydrous ammonia, hydrated lime, limestone and general O&M expenses are included in the Air Quality Compliance Program line item. The projected cost for limestone associated with operation of the Plant Crist, Plant Daniel, and Plant Scherer 3 scrubbers is approximately $9.2 million. The projected 2019 expenses for this line item total $21,813,790.

Q. What activities are included in the Crist Water Conservation line item (Line Item 1.22)?

A. The Crist Water Conservation line item includes general O&M expenses associated with the Plant Crist reclaimed water systems, such as piping and valve maintenance. Expenses totaling $428,542 are projected to be incurred during 2019 for this line item.

Q. What activities are included in the Smith Water Conservation line item (Line Item 1.24)?

A. The Smith Water Conservation line item includes general O&M expenses associated with the Plant Smith deep injection well system that was placed in service during 2016 as part of the Plant Smith Reclaimed Water capital project. The projected costs include sampling and analytical charges, chemicals, and mechanical integrity testing expenses required by the FDEP permit. Gulf was granted approval for recovery of the Plant Smith Reclaimed Water project in FPSC Order No. PSC-09-0759-FOF-EI. Expenses totaling $190,000 are projected to be incurred during 2019 for this line item.

Q. Please describe the emission allowance expense line items.

A. This line item includes projected allowance expenses for Gulf's generation. Line Item 1.26 includes $7,214 of projected expenses for annual NOx allowances, Line Item 1.27 includes $7,887 of projected expenses for seasonal NOx allowances, and Line Item 1.28 includes $37,762 of projected expenses for SO_2 allowances during 2019.

Q. Do each of the capital projects and O&M activities that have projected costs in 2019 meet the ECRC statutory guidelines?

A. Yes. The projects included in Gulf's 2019 ECRC projection filing meet the requirements of the ECRC statute and are consistent with the Commission's precedents regarding environmental cost recovery. Each of the capital projects and O&M activities set forth in Mr. Boyett's schedules includes only prudent costs that are not recovered through some other cost recovery mechanism or base rates. The projected environmental costs are necessary to achieve and/or maintain compliance with environmental laws, rules, and regulations.

Q. Mr. Markey, does this conclude your testimony?

A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 20180007-EI

Before me, the undersigned authority, personally appeared Richard M. Markey, who being first duly sworn, deposes and says that he is the Director of Environmental Affairs of Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of his knowledge and belief. He is personally known to me.

Richard M. Markey

Richard M. Markey
Director of Environmental Affairs

Sworn to and subscribed before me this 24th day of August, 2018.

Melissa Darnes

Notary Public, State of Florida at Large

NOTARY PUBLIC STATE OF FLORIDA
MELISSA DARNES
MY COMMISSION # FF 912698
EXPIRES: December 17, 2019
Bonded Thru Budget Notary Services

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Air Quality Assurance Testing
PEs 1006 and 1244

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
This line item includes the audit test trailer and associated support equipment used to conduct Relative Accuracy Test Audits (RATAs) on the Continuous Emission Monitoring Systems (CEMS) as required by the 1990 Clean Air Act Amendments (CAAA).

Accomplishments:
The RATA test trailer and CEMs system was replaced during the 2010 recovery period. These replacements provide Gulf with the accuracy and reliability needed to accurately measure SO_2, NOx, and CO_2 and to further maintain compliance with CAAA requirements.

Project-to-Date: Plant-in-service of $65,000 projected at December of 2019

Progress Summary: In 2019, Gulf will replace the analyzers located in the RATA test trailer.

Projections: Expenditures reflected in the 2019 projection filing for this line item total $65,000.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist 5, 6 & 7 Precipitator Projects
PEs 1038, 1119, 1216, 1243 and 1249

FPSC Approval: Order No. PSC-94-0044-FOF-EI
Order No. PSC-09-0759-FOF-EI

Description:
The Plant Crist precipitator projects are necessary to improve particulate removal capabilities. The larger more efficient precipitators with increased collection areas improve particulate collection efficiency.

Accomplishments:
The precipitators have successfully reduced particulate emissions. The upgraded Crist Unit 7 precipitator was placed in service during 2004 as part of the FDEP agreement. The Plant Crist Unit 6 precipitator upgrade was placed in service in April 2012. The digital control system for the Unit 6 precipitator was upgraded during 2015.

Project-to-Date: Plant-in-service of $33,677,323 projected at December 2019.

Progress Summary: In Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist 7 Flue Gas Conditioning
PE 1228

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
This project included the injection of sulfur trioxide into the flue gas to enhance particulate removal and improve the collection characteristics of fly ash. Retirement of the Plant Crist Unit 7 flue gas conditioning system was completed during July 2005.

Accomplishments:
The system enhanced particulate removal in the precipitator.

Project-to-Date: $0

Progress Summary: Retired

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Low NO_x Burners, Crist 6 & 7
PEs 1234, 1236, 1242 and 1284

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
Low NO_x burners are unique burners installed to decrease the NO_x emissions that are formed during the combustion process. This equipment was installed to meet the requirements of the 1990 Clean Air Act Amendments.

Accomplishments:
The Low NO_x burner systems have proven effective in reducing NO_x emissions. The low NO_x burners on Crist Unit 7 were replaced during the 2003-2004 time frame and the Crist Unit 6 burners were replaced during December 2005. The digital control systems for the Unit 6 and Unit 7 Low NOx burners were upgraded during 2015. The Crist Unit 7 band gas canes on the Low NOx burners were upgraded with new retractable gas gun burning technology during 2016. Additional gas gun upgrades were installed in 2018.

Project-to-Date: Plant-in-service of $13,634,258 projected at December 2019.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: CEMs – Plant Crist and Daniel
PEs 1001, 1060, 1154, 1164, 1217, 1240, 1245, 1247, 1256, 1283, 1286, 1289, 1290, 1311, 1312, 1316, 1323, 1324, 1325, 1357, 1358, 1364, 1558, 1570, 1592, 1658, 1829and 1830

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Continuous Emission Monitoring (CEM) line item includes dilution extraction emission monitors that measure the concentrations of sulfur dioxide (SO_2), carbon dioxide (CO_2) and nitrogen oxides (NO_x) in the flue gas. Opacity and flow monitors were also installed under this line item. All CEMs monitors were installed pursuant to the 1990 Clean Air Act Amendments (CAAA).

Accomplishments:
The systems at both Gulf and Mississippi Power continue to successfully exceed routine quality assurance/quality control (QA/QC) audits as required by the 1990 CAAA.

Project-to-Date: Plant-in-service of $4,690,600 projected at December 2019.

Progress Summary:
The Plant Daniel Units 1 & 2 gas analyzers were replaced during 2005 and the flow monitors were replaced during 2007. During the 2009 recovery period, the CEMS project included replacement of opacity monitors at Plant Crist on Units 4 through 7 and the installation of CEMs equipment for the new Plant Crist scrubber stack to monitor SO_2, NOx, CO_2 and flow. Plant Crist completed the installation of two CEMS bypass monitoring systems for Units 4 through 7 in the 2011-2012 timeframe. In 2017, Plant Crist replaced the Unit 7 flue gas monitors. During 2019, Plant Crist will replace CEMS monitors located in the scrubber stack.

Projections: Expenditures reflected in the 2019 projection filing for this line item total $200,000.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Substation Contamination Remediation
PEs 1007, 2859, 3400, 3412, 3463 and 3477

FPSC Approval: Order No. PSC-95-1051-FOF-EI

Description:
Three groundwater treatment systems were purchased for the treatment of contaminated groundwater at substation sites. Capital components of substation soil remediation projects are also included in the line.

Accomplishments:
Systems have proven effective in groundwater remediation. During 2014, additional groundwater recovery well pumps and controls were added to the existing Ft. Walton substation treatment system.

Project-to-Date: Plant-in-service of $4,979,829 projected at December 2019.

Progress Summary: During 2019, Gulf will be completing replacement of the groundwater remediation equipment at the Fort Walton substation and completing construction of the Wewa substation remediation system.

Projections: Expenditures reflected in the 2019 projection filing for this line item total $1,496,496.

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Raw Water Flowmeters - Plants Crist and Smith
PEs 1155 and 1606

FPSC Approval: Order No. PSC-96-1171-FOF-EI

Description:
The Raw Water Flow Meters capital project was necessary for Gulf to comply with the Plant Crist and Plant Smith Consumptive Use and Individual Water Use permits issued by the Northwest Florida Water Management District (NWFWMD). These permits require the installation and monitoring of in-line totaling water flow meters on all existing and future water supply wells. Gulf incurred costs related to the installation and operation of new in-line totaling water flow meters at Plant Crist and Plant Smith for implementation of this new activity.

Accomplishments:
The raw water flow meters have been installed at Plant Crist and Plant Smith.

Project-to-Date: Plant-in-service of $149,950 projected at December 2019.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Cooling Tower Cell
PE 1232

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Crist Cooling Tower is a pollution control device which allows condenser cooling water to be continually reinjected into the condenser. The cooling tower reduces water discharge temperatures to meet the National Pollution Discharge Elimination System (NPDES) industrial wastewater permit requirements.

Accomplishments:
Plant Crist has maintained compliance with the temperature discharge limits as required by the facility's NPDES Permit. The original cooling tower cell was retired during July 2007 when the new Crist Unit 7 cooling tower was placed-in-service in June 2007 as part of the Crist scrubber project that is reflected in Air Quality Compliance Program.

Project-to-Date: $0

Progress Summary: Retired

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Dechlorination System
PEs 1180 and 1248

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
National Pollutant Discharge Elimination System wastewater permits require reductions in chlorine concentrations prior to discharge from the plant. The Crist dechlorination system uses sodium bisulfite to chemically eliminate the residual chlorine present in the plant industrial wastewater prior to discharge.

Accomplishments:
During 2011-2012 Plant Crist replaced the existing sodium bisulfate storage tank and installed a new dechlorination system for the Unit 6 and Unit 7 cooling tower blowdowns and the ECUA return water pit. These systems are necessary in order to dechlorinate the industrial wastewater prior to discharge. The system has been effective in maintaining chlorine discharge limits.

Project-to-Date: Plant-in-service of $380,697 projected at December 2019.

Progress Summary: In service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Diesel Fuel Oil Remediation
PE 1270

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
The Plant Crist diesel fuel oil remediation project included installing monitoring wells in the vicinity of the Crist diesel tank systems. The project also included the installation of an impervious cap to reduce migration of contaminants to groundwater.

Accomplishments: Monitoring wells and an impervious cap were installed.

Project-to-Date: Plant-in-service of $68,923 projected at December 2019.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Bulk Tanker Unloading Secondary Containment
PE 1271

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
The Crist Bulk Tanker Unloading Secondary Containment project was necessary to minimize the potential risk of an uncontrolled discharge of pollutants into the waters of the United States. Secondary containment was required to be installed for tank unloading racks pursuant to the Federal Spill Prevention Control and Countermeasures (SPCC) regulation (40 CFR Part 112).

Accomplishments:
The Plant Crist unloading area secondary containment area complies with current SPCC regulatory requirements.

Project-to-Date: Plant-in-service of $101,495 projected at December 2019.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist IWW Sampling System
PE 1275

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
The 1993 revision to Plant Crist's National Pollutant Discharge Elimination System (NPDES) industrial wastewater permit moved the compliance point from the end of the discharge canal to a point upstream of Thompson's Bayou. To allow for this sample point modification, an access dock was constructed in the discharge canal. The Crist Industrial Wastewater (IWW) project also included a small building for monitoring and sampling equipment.

Accomplishments:
The dock is complete and samples are being collected at the required compliance point.

Project-to-Date: Plant-in-service of $59,543 projected at December 2019.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

**Description and Progress Report of
Environmental Compliance Activities and Projects**

**Title: Sodium Injection System
PE 1214**

FPSC Approval: Order No. PSC-99-1954-FOF-EI

Description:
The Sodium Injection System line item includes silo storage systems and associated components that inject sodium carbonate directly onto the coal feeder belt to enhance precipitator performance when burning low sulfur coal. Sodium injection was used at Plant Smith on Units 1 and 2 and is still in use at Plant Crist on Units 4 and 5. The injection of sodium carbonate as an additive to low sulfur coal reduces opacity levels to maintain compliance with the Clean Air Act provisions.

Accomplishments:
The silo storage and injection system components at Plant Crist have been installed and the system is fully operational. The Smith system was retired in April 2016 after the coal units ceased operations.

Project-to-Date: Plant-in-service of $284,622 projected at December 2019.

Progress Summary: In Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Smith Stormwater Collection System
PE 1446

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
The National Pollutant Discharge Elimination System (NPDES) stormwater program requires industrial facilities to install stormwater management systems in order to prevent the discharge of impacted stormwater to the surface waters of the United States.

Accomplishments:
The Plant Smith stormwater sump system has been effective in managing onsite stormwater.

Project-to-Date: Plant-in-service of $2,764,379 projected at December 2019.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Smith Waste Water Treatment Facility
PEs 1466 and 1643

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
During the 1990's a domestic wastewater treatment facility was installed at Plant Smith to replace the septic tank system that was installed in the early 1960's. In April 2004 a new wastewater treatment facility with additional capacity was installed to replace the facility installed in the 1990's. The new treatment plant includes aeration and chlorination of the wastewater prior to discharge in the Plant Smith ash pond.

Accomplishments: Plant Smith has maintained compliance with the NPDES industrial wastewater permit.

Project-to-Date: Plant-in-service of $591,865 projected at December 2019.

Progress Summary: The current domestic wastewater treatment plant needs to be relocated as part of the Plant Smith ash pond closure project since the area will used for future dry ash stacking. Gulf plans to place the new wastewater treatment system in service in early 2019.

Projections: N/A.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Daniel Ash Management Project
PEs 1501, 1535, 1555 and 1819

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The original Daniel Ash Management project included the installation of a dry ash transport system, lining the bottom of the ash pond, closure and capping of the existing fly ash pond, and expansion of the landfill area. During 2006 Plant Daniel completed construction of a new on-site ash storage facility in preparation for the completion and closure of the existing landfill area.

Accomplishments: Construction of the new on-site ash storage facility was completed in 2006. Portions of the original Daniel ash storage facility were closed in place during 2010.

Project-to-Date: Plant-in-service of $14,950,124 projected at December 2019.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

**Description and Progress Report of
Environmental Compliance Activities and Projects**

**Title: Smith Water Conservation
PEs 1601**

**FPSC Approval: Order No. PSC-01-1788-FOF-EI and
Order No. PSC-09-0759-FOF-EI**

Description:
Specific Condition nine of Plant Smith's consumptive use permit, issued by the Northwest Florida Water Management District (NWFWMD), requires the plant to implement measures to increase water conservation and efficiency at the facility. Phase I of the Smith Water Conservation project consisted of adding pumps, piping, valves, and controls to reclaim water from the ash pond. Phase II, the Smith Closed Loop Cooling System for the laboratory sampling system, was installed during 2005 to further reduce groundwater usage. Phase III includes investigating and installing a deep injection will system to allow Plant Smith to utilize reclaimed water.

As discussed in previous filings, Gulf has determined that it is feasible to inject reclaimed water into the Plant Smith deep injection well system. Gulf has installed three deep injection wells, piping, and initial equipment needed for the pump station.

Project-to-Date: Plant-in-service of $34,299,806 projected at December 2019.

Progress Summary: During the remainder of 2018 and 2019, Gulf will obtain additional operational data required to design the final pump station, wastewater treatment equipment, as well as additional piping and associated storage capacity. Gulf plans to begin construction of the reclaimed water pump station and wastewater treatment equipment during 2019.

Projections: The projected 2019 expenditures for this line item total $13,033,532.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Underground Fuel Tank Replacement
PE 4397

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Underground Fuel Tank Replacement Program provided for the replacement of Gulf's underground storage tanks with new above ground tanks (ASTs). The installation of ASTs significantly reduced the risk of potential petroleum product discharges, groundwater contamination, and subsequent remediation activities.

Accomplishments:
All underground storage tanks have been replaced with above ground tank systems.

Project-to-Date: $0

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist FDEP Agreement for Ozone Attainment
PEs 1031, 1158, 1167, 1199, 1250, 1258, 1287 and 1958

FPSC Approval: Order No. PSC-02-1396-FOF-EI

Description:
The Florida Department of Environmental Protection (FDEP) and Gulf Power entered into an agreement on August 28, 2002 to support Escambia/Santa Rosa County area's effort to maintain compliance with the 8-hour ozone ambient air quality standards. This agreement included a requirement for Gulf to install Selective Catalytic Reduction (SCR) controls on Plant Crist Unit 7, relocate the Crist Unit 7 precipitator, and install a NO_x reduction technology on Plant Crist Unit 6, and Units 4 and 5 if necessary, to meet the NO_x standard specified in the Agreement.

Accomplishments: The new Crist Unit 7 precipitator and SCR were placed in service during 2004 and 2005, respectively. The Crist Unit 6 Selective Non-Catalytic Reduction (SNCR)/low NOx burners with Over-Fired Air (OFA) technologies were then placed in service during November 2005. The Crist Unit 4 and Unit 5 SNCRs were subsequently placed in service during April 2006. The Crist Unit 6 SNCR was retired during the Spring of 2012 when the Crist Unit 6 SCR was placed in-service. Gulf replaced one layer of the Plant Crist Unit 7 SCR catalyst during the Fall of 2014. Gulf replaced the Plant Crist Unit 7 SCR ammonia unloading piping during 2015 and upgraded the digital control system for the Unit 7 SCR. Gulf replaced a layer of the Plant Crist unit 7 SCR catalyst and installed the Plant Crist unit 6 flame scanner during 2016. Gulf replaced the Crist Unit 7 Fgas fans, a layer of the Plant Crist unit 7 SCR catalyst, and performed work on the Unit 7 SCR during 2018.

Project-to-Date: Plant-in-service of $122,186,973 projected at December 2019.

Progress Summary: During 2019, Gulf will be making a progress payment for the catalyst on Crist Unit 7 being replaced during the 2020 outage.

Projections: The projected 2019 expenditures for this line item total $200,000.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: SPCC Compliance
PEs 1272, 1404, 1628 and 4418

FPSC Approval: Order No. PSC-03-1348-FOF-EI

Description:
The SPCC Compliance projects were required as the result of a more stringent July 2002 revision to Title 40 Code of Federal Regulation Part 112, which is commonly referred to as the Spill Prevention Control and Countermeasures (SPCC) regulation. The 2002 regulatory revision specifically included oil-containing electrical equipment within the scope of the regulation. Therefore, oil-filled electrical equipment that has the potential to discharge to navigable waters must be provided with appropriate containment and/or diversionary structures to prevent such a discharge. The 2002 revisions also resulted in oil storage containers having a capacity greater than or equal to 55 gallons being classified as bulk storage containers that are subject to the secondary containment requirements in 40 CFR Part 112.8(c).

Accomplishments: The 2006 SPCC project at Plant Crist routed stormwater from the switchyard drains to the new oil skimming sump where any potential spill could be captured, preventing the oil from reaching surface water. During 2009, Plant Smith installed secondary containment for a padmount transformer located along the ash pond discharge canal. During 2012, Plant Smith installed a secondary containment system for the diesel emergency sump pump system. During 2017, Gulf installed a double walled fuel tank at the Panama City Beach Facility for the emergency generator.

Project-to-Date: Plant-in-service of $947,925 projected at December 2019.

Progress Summary: In-service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Common FTIR Monitor
PE 1297

FPSC Approval: Order No. PSC-03-1348-FOF-EI

Description:
The purchase of a Fourier Transform Infrared (FTIR) spectrometer, a device used to measure and analyze various low concentration stack gas emissions, was required at Plant Crist under Title V regulations.

Accomplishments: Purchasing the FTIR instrument has enabled Gulf Power to measure ammonia slip emissions as required by the Plant Crist air permit.

Project-to-Date: Plant-in-service of $62,870 projected at December 2019.

Progress Summary: In-Service

Projections: N/A

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Precipitator Upgrades for Compliance Assurance Monitoring Compliance
PEs 1175, 1191, 1305 and 1330

FPSC Approval: Order No. PSC-04-1187-FOF-EI

Description: Compliance Assurance Monitoring (CAM) Precipitator Upgrades were required to comply with new CAM regulations incorporated into Gulf's Title V permits in the 2005 timeframe. CAM requirements are regulated under Title V of the 1990 Clean Air Act Amendments (CAAA) which requires a method of continuously monitoring particulate emissions. Opacity can be used as a surrogate parameter if the precipitator demonstrates a correlation between opacity and particulate matter. Gulf demonstrated this correlation by stack testing in 2003 and 2004, and the results were included as part of the CAM plans in Gulf's Title V Air Permits effective January 2005. Several precipitator upgrades have been necessary to meet the more stringent surrogate opacity standards under CAM.

Accomplishments: The Plant Smith Unit 2 and Unit 1 precipitator upgrades were placed in service during April 2005 and May 2007, respectively. The Plant Scholz Unit 2 precipitator upgrade was completed during December of 2007. The Plant Crist Units 4 and 5 precipitator upgrades were placed in-service during March of 2008. The Scholz precipitators were retired in 2015. The Plant Smith precipitators were retired in April 2016 after the Plant Smith Units 1 & 2 ceased operations.

Project-to-Date: Plant-in-service of $13,997,696 projected at December 2019.

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Plant Groundwater Investigation
PEs 1218 and 1361

FPSC Approval: Order No. PSC-05-1251-FOF-EI

Description: The Florida Department of Environmental Protection (FDEP) lowered the arsenic groundwater standard from 0.05 mg/L to 0.01 mg/L effective January 1, 2005. Historical groundwater monitoring data from Plants Crist and Scholz indicated that these facilities may be unable to comply with the lower standard.

Accomplishments: The Plant Crist and Plant Scholz projects have been canceled because Gulf has been released from any arsenic remedial actions at these sites.

Project-to-Date: $0

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Water Conservation Project
PEs 1178, 1227 and 1298

FPSC Approval: Order No. PSC-05-1251-FOF-EI

Description:
This project is part of the Plant Crist water conservation and consumptive use efficiency program to reduce the demand for groundwater and surface water withdrawals. Specific Condition six of the Northwest Florida Water Management District Individual Water Use Permit Number 19850074 issued January 27, 2005 requires Plant Crist to implement measures to increase water conservation and efficiency at the facility. The first Plant Crist Water Conservation project was placed in service during 2006. This project included installing automatic level controls on the fire water tanks to reduce groundwater usage. The second phase of the project involves utilizing reclaimed water from ECUA's wastewater treatment plant to reduce the demand for groundwater and surface water withdrawals at Plant Crist. The Northwest Florida Water Management District has agreed that this is a valid project to pursue for continued implementation of the water conservation effort.

Accomplishments: Level controls were installed on the fire tank system during 2006. Portions of the Plant Crist reclaimed water project were placed in-service in 2009 and 2010. Gulf began receiving reclaimed water from ECUA in November 2010. During the 2011-2012 timeframe, Gulf installed defoaming and acid injection systems for the Units 6-7 cooling towers to treat scaling and foam associated with reclaimed water usage. During 2017, Gulf replaced two header pumps that were installed when Plant Crist began receiving reclaimed water. In 2018, Gulf's plan is to replace the remaining three header pumps.

Project-to-Date: Plant-in-service of $20,195,681 projected at December 2019.

Progress Summary: During 2019, Gulf plans on replacing pumps, piping, valves and motors that were installed when Plant Crist began receiving reclaimed water.

Projections: The projected 2019 expenditures for this line item total $100,000.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Plant NPDES Permit Compliance Projects
PEs 0433, 1204 and 1299

FPSC Approval: Order No. PSC-05-1251-FOF-EI

Description: The water quality based copper effluent limitations included in Chapter 62 Part 302, Florida Administrative Code (F.A.C.) were amended in April 2002 with an effective date of May 2002. The more stringent hardness based standard is included by reference in the Plant Crist National Pollutant Discharge Elimination System (NPDES) industrial wastewater permit.

Accomplishments: Plant Crist installed stainless steel condenser tubes on Unit 6 during June 2006 in an effort to meet the revised water quality standards during times of lower hardness in the river water. During 2008, Plant Crist completed the second phase of the project which involved installing a chemical treatment system in the ash pond. During 2010, Gulf completed the third phase of the project that included installing an aeration system in the ash pond. During 2011-2012, Plant Crist completed installation of a new caustic tank and a sulfuric acid tank as part of the ash pond chemical treatment system.

During 2018, Plant Smith will complete replacement of the second discharge canal crossover to allow for continued safe access for obtaining representative main plant discharge samples as required by the Plant Smith NPDES industrial wastewater permit.

Project-to-Date: Plant-in-service of $6,167,068 projected at December 2019.

Progress Summary: See Accomplishments

Projections: N/A

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Air Quality Compliance Program
PEs 0560, 0860,1034, 1035, 1036, 1037, 1067, 1095, 1168, 1188, 1222, 1233, 1279, 1288, 1362, 1505, 1508, 1512, 1513, 1517, 1551, 1552, 1646, 1684, 1701, 1727, 1728, 1729, 1768, 1774, 1778, 1791, 1798, 1809, 1810, 1824, 1826, 1909, 1911, 1913 and 1950

FPSC Approval: Order No. PSC-06-0972-FOF-EI

Description: This line item covers the prudently incurred costs for compliance with Gulf's Air Quality Compliance Program including the expenses associated with Gulf's ownership portion of the Scherer 3 baghouse, SCR, and scrubber projects and associated equipment.

Accomplishments: The Plant Smith Unit 1 and Unit 2 SNCRs were placed in service during May 2009 and December 2008, respectively. The Plant Smith SNCRs were retired in April 2016 after Plant Smith Units 1 & 2 ceased operations. The Crist Units 4 - 7 scrubber project was placed in-service in December of 2009 and the Crist Unit 6 hydrated lime injection system was placed in-service in 2011. The Plant Crist Unit 6 SCR was placed-in-service in April of 2012. The Plant Daniel scrubber projects were placed in-service in November 2015. Plant Daniel's bromine and activated carbon injection systems were placed in-service in December 2015. The scrubbers when used in conjunction with the bromine and activated carbon injection systems will allow Plant Daniel to comply with the MATS standards. Plant Scherer 3 baghouse was placed in-service February 2009, SCR in-service December 2010, and scrubber in-service March 2011.

Project-to-Date: Plant-in-service of $1,360,480,617 projected at December 2019.

Progress Summary: During 2019, the Air Quality Compliance program includes costs associated with the following: Plant Crist and Plant Daniel scrubbers, Plant Crist Unit 6 SCR, as well as the Plant Daniel Low NOx burners. More specifically, it includes expenditures for the Plant Crist gypsum storage area, gas cooling nozzles, scrubber agitator gear box, Unit 6 SCR catalyst layer, elevator, and air compressors. Approximately $6.2 million is projected for expansion of the Plant Crist UIC pump station. The expansion will allow Plant Crist to utilize two additional wells for disposal of wastewater generated from the gypsum storage facility and associated groundwater remediation system. Plant Crist will also be constructing a new limestone system that will add limestone as needed to the coal to help maintain the performance of catalyst used in the SCRs. The cost of the new limestone system is projected to be approximately $1 million. During 2019, Gulf will be making a progress payment of $500,000 for a new scrubber alignment grid at Plant Crist that will be installed in the 2020 scrubber outage. Plant Daniel will also be replacing the low NOx burners on Unit 2, which have reached the end of their useful life. The cost of the new low NOx burners is approximately $490,000.

Projections: The total projected 2019 expenditures for this line item total $8,660,145.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: General Water Quality
PEs 0831, 0861 and 1280

FPSC Approval: Order No. PSC-06-0972-FOF-EI

Description: The General Water Quality line item includes capital expenditures required to ensure compliance with Gulf Power's NPDES industrial wastewater permits. Gulf purchased a boat during 2007 for surface water sampling required by the Plants Crist, Smith and Scholz National Pollutant Discharge Elimination System (NPDES) permits. The permits had new conditions which required Gulf to establish a biological evaluation plan and implementation schedule for each plant.

Accomplishments: The General Water Quality sampling boat was purchased during 2007. It is currently being used to conduct Gulf's surface water sampling for Plants Crist, Smith, and Scholz. Plant Crist installed additional groundwater monitoring wells during 2017 and plans to install additional wells in 2018 for compliance with the plant's NPDES industrial wastewater permit.

Project-to-Date: Plant-in-service of $832,922 projected at December 2019.

Progress Summary: N/A

Projections: N/A

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Coal Combustion Residuals
PEs 0404, 0412, 0424, 0514, 1597, 1598, 1599, 1641, 1997, 4405, 4430, 4440, 6756, 6757, 6759, 6764 and 6765

FPSC Approval: PSC-15-0536-FOF-EI

Description: The Coal Combustion Residuals (CCR) program includes expenses related to the regulation of Coal Combustion Residuals by the United States Environmental Protection Agency ("EPA") and the Florida Department of Environmental Protection ("FDEP"). On April 17, 2015 EPA published the final CCR rule in the Federal register regulating CCR disposal under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The CCR rule is located in Title 40 Code of Federal Regulations (CFR) Parts 257 and 261. The CCR rule regulates the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste at active generating power plants. The rule applies to CCR Units at Gulf's Plants Crist, Scherer, Smith, and Daniel. Plant Scherer is also regulated under Georgia's Environmental Protection Division CCR Rule, which requires permit applications to be submitted for the facility's ash pond and CCR landfill by November 22, 2019.

Accomplishments: Gulf installed additional groundwater monitoring wells at Plants Crist, Daniel, and Smith during 2015. In 2017, Gulf completed construction of a slurry wall and new industrial wastewater treatment pond at Scholz. Construction activities for the ash pond closures at Plant Scholz and Plant Smith began in 2018.

Project-to-Date: Plant-in-service of $41,778,858 projected at December 2019.

Progress Summary: During 2019, the Scholz ash pond closure project will include construction of a new stormwater management system, transferring CCR material to a dry stack area within the footprint of the pond, and capping the dry stack area with closure turf material. At Plant Smith, Gulf will proceed with construction of new industrial wastewater ponds and a slurry wall as well as transferring CCR material to a dry stack area within the footprint of the pond during 2019.

Engineering and construction of the Scherer dry ash handling system is expected to be completed in 2019 and design and construction of the CCR wastewater management system will continue in 2019. In addition, detailed engineering and construction will continue on Cell 3 of the onsite landfill for CCR storage. Plant Scherer will also proceed with siting studies and preliminary design for a new landfill.

Final design and initial construction of a new wastewater treatment and bottom ash handling system will occur at Plant Daniel during 2019. Plant Daniel will need to reroute wastewater streams from the ash pond to a new wastewater system prior to beginning closure of the bottom ash pond in 2021. Plant Daniel is currently in the process of completing studies to determine the most cost-effective technologies and system design.

Projections: The total projected 2019 expenditures for this line item total $50,765,515.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Steam Electric Power Effluent Limitations Guidelines and Standards
PEs 1193, 1912 and 6754

FPSC Approval: PSC-15-0536-FOF-EI

Description: In 2015, the EPA finalized revisions to the steam electric effluent limitations guidelines (ELG) rule, which imposes stringent technology-based requirements for certain waste streams from steam electric generating units. The revised technology-based limits and compliance dates will require extensive modifications to existing ash and flue gas desulfurization (FGD) scrubber wastewater management systems or the installation and operation of new wastewater management systems. Compliance applicability dates in the 2015 rule ranged from November 1, 2018, to December 31, 2023.

On September 18, 2017, EPA published a final rule in the Federal Register that delayed the earliest ELG applicability date for FGD wastewater and bottom ash transport water from the original (2015 rule) “as soon as possible date” of November 1, 2018 to a new “as soon as possible” date of November 1, 2020, to allow time for EPA to reconsider the requirements for FGD wastewater and bottom ash transport water. The 2017 rule did not change the latest applicability date or “no later than” date of December 31, 2023.

State environmental agencies will incorporate specific applicability dates in the NPDES permitting process based on requirements provided for each waste stream. The EPA plans to propose ELG rule revisions in December 2018 and to finalize the rulemaking in 2019.

Project-to-Date: Plant-in-service of $5,655,259 projected at December 2019.

Progress Summary: Gulf has projected expenditures in 2019 for engineering and design of Gulf’s ownership portion of the Scherer scrubber wastewater treatment system.

Projections: The projected 2019 expenditures for this line item total $456,695.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: 316(b) Cooling Water Intake Structure Regulation
PE 1691

FPSC Approval: Order No.

Description: On August 15, 2014, the EPA published final regulations under Section 316(b) of the Clean Water Act for cooling water intake structures at existing electric generating facilities. The rule found in Title 40 Parts 122 and 125 of the Code of Federal Regulations, (See Exhibit RMM-1), became effective on October 14, 2014, requiring existing facilities withdrawing greater than 2 million gallons per day (MGD) to adopt one of seven options for addressing impingement at the entrance to existing cooling water intake structures. Although the ultimate 316(b) compliance strategy and design will be approved by the state environmental permitting agencies, with possible input from the U.S. Fish and Wildlife Service and National Marine Fisheries Service (Services) and EPA, Gulf Power's preliminary studies indicate Plant Smith will need to install new lower capacity intake pumps and a closed-cycle cooling tower monitoring system for the existing Unit 3 closed-cycle cooling tower.

Accomplishments: N/A

Project-to-Date: Plant-in-service of $2,000,000 projected at December 2019.

Progress Summary: Gulf plans to install new lower capacity intake pumps at Plant Smith during 2019. The Plant Smith industrial wastewater permit requires Gulf to submit information required under the Cooling Water Intake Structure 316(b) rule with its next permit renewal that is due in April of 2019 for FDEP review and approval.

Projections: The total projected 2019 expenditures for this line item total $2,000,000.

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Mercury Allowances

FPSC Approval: Order No. PSC-07-0721-S-EI

Description:
Mercury Allowances were included as part of Gulf's March 2007 CAIR/CAMR/CAVR Compliance Program. The purchase of allowances in conjunction with the retrofit projects comprised the most reasonable, cost-effective means for Gulf to meet the CAIR, CAMR and CAVR requirements. On February 8, 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion vacating EPA's CAMR. The vacatur became effective with the issuance of the court's mandate on March 14, 2008, nullifying CAMR mercury emission control obligations and monitoring requirements. In response to the CAMR vacatur, mercury allowances have been removed from Gulf's Air Quality Compliance Program.

Accomplishments: N/A

Project-to-Date: N/A

Progress Summary: N/A

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Annual NO_x Allowances

FPSC Approval: Order No. PSC-07-0721-S-EI

Description:
Although the retrofit installations set forth in Gulf's Air Quality Compliance Program significantly reduce emissions, they will not result in Gulf achieving CAIR compliance levels without the purchase of some emission allowances. Thus, Gulf's Compliance Program called for the purchase of allowances as needed. The purchase of allowances in conjunction with the retrofit projects comprised the most reasonable, cost-effective means for Gulf to meet CAIR requirements. CAIR has now been replaced by CSAPR.

Accomplishments: N/A

Project-to-Date: N/A

Progress Summary:
Gulf began surrendering annual NOx allowances during 2009.

Projections: The projected 2019 O&M Annual NOx allowance expenses are $7,214.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

**Description and Progress Report of
Environmental Compliance Activities and Projects**

Title: Seasonal NO_x Allowances

FPSC Approval: Order No. PSC-07-0721-S-EI

Description:
Although the retrofit installations set forth in Gulf's Air Quality Compliance Program significantly reduce emissions, the projects would not result in Gulf achieving CAIR/CASPR compliance levels without the purchase of some emission allowances. Thus, Gulf's Compliance Program called for the purchase of allowances as needed. The purchase of allowances in conjunction with the retrofit projects comprised the most reasonable, cost-effective means for Gulf to meet CAIR/CSAPR requirements.

Accomplishments: N/A

Project-to-Date: N/A

Progress Summary:
Gulf began surrendering seasonal NOx allowances during 2009.

Projections: The projected 2019 O&M Seasonal NOx allowance expenses are $7,887.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of Environmental Compliance Activities and Projects

Title: SO_2 Allowances

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
Part of Gulf's strategy to comply with the Acid Rain Program under the Clean Air Act Amendments of 1990 was to bring several of Gulf's Phase II generating units into compliance early and bank the SO_2 allowances associated with those units. SO_2 reductions under the CAIR program utilized this program requiring an increased rate of surrender beginning in 2010. Gulf's bank has slowly been drawn down over the years due to more allowances being consumed than are allocated to Gulf by EPA. Gulf proposed to meet this shortfall by executing forward contracts to secure allowances supplemented with forward contracts, swaps, and spot market purchases of allowances as prices dictate.

Accomplishments: Gulf executed forward contacts to secure allowances during 2006, 2007, and 2009.

Project-to-Date: N/A

Progress Summary: See Accomplishments

Projections: The projected 2019 O&M SO_2 allowance expenses are $37,762.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

**Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.1**

Title: Sulfur

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Plant Crist Unit 7 sulfur trioxide (SO_3) flue gas system allowed for the injection of SO_3 into the flue gas stream. The addition of sulfur trioxide to the flue gas improved the collection efficiency of the precipitator when burning a low sulfur coal. Sulfur trioxide agglomerated the particles which in turn enhanced the collection efficiency of the precipitator.

Accomplishments:
The flue gas injection system was retired during 2005.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.2

Title: Air Emission Fees

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
Air Emission Fees are the annual fees required by the Florida Department of Environmental Protection (FDEP), Georgia Environmental Protection Division (EPD), and Mississippi Department of Environmental Quality (MDEQ) under Title V of the 1990 Clean Air Act Amendments.

Accomplishments:
Fees have been paid by due dates.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $305,099

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.3

Title: Title V

FPSC Approval: Order No. PSC-95-0384-FOF-EI

Description:
Title V expenses are associated with preparation of the Clean Air Act Amendments (CAAA) Title V permit applications and the subsequent implementation of Title V permits. Renewal of the Title V permits is on a five-year cycle (i.e. 2014, 2019, etc). Title V permits are periodically revised between renewals to incorporate major changes or modifications of a source.

Accomplishments:
Gulf's Title V permit renewals were finalized in January 2015 and are valid for a 5-year period. Title V permit amendments to incorporate a new Southern System NOx Averaging Plan for the Acid Rain Program (Title IV Permits) were issued by FDEP during July 2016 for Plant Crist, Plant Scholz and Plant Smith. Gulf's Perdido Landfill Gas-to-Energy Facility Title V permit was issued on November 16, 2016 and is valid for a 5-year period.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $293,254

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.4

Title: Asbestos Fees

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
Asbestos Fees include both annual and individual project fees due to the Florida Department of Environmental Protection (FDEP) for asbestos abatement projects.

Accomplishments:
Fees are paid as required by FDEP.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $1,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.5

Title: Emission Monitoring

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Emission Monitoring program provides quality assurance/quality control testing for Continuous Emission Monitoring systems, including Relative Accuracy Test Audits and Linearity Tests, as required by the Clean Air Act Amendments (CAAA) of 1990.

Accomplishments:
All systems are in compliance.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $739,036

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.6

Title: General Water Quality

FPSC Approval: **Order No. PSC-94-0044-FOF-EI**
Order No. PSC-04-1187-FOF-EI
Order No. PSC-08-0775-FOF-EI
Order No. PSC-11-0553-FOF-EI

Description:
The General Water Quality program includes activities undertaken pursuant to the Company's NPDES industrial wastewater permit including dechlorination, surface and groundwater monitoring studies and associated assessment activities, and soil contamination studies. This line item also includes expenses for Gulf's Cooling Water Intake program, the Impaired Waters Rule, Storm Water Maintenance, and the Impoundment Integrity project.

Accomplishments:
All activities are on-going in compliance with applicable environmental laws, rules, and regulations.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $2,014,654.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.7

Title: Groundwater Contamination Investigation

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Groundwater Contamination Investigation project includes sampling and testing to determine possible environmental impacts to soil and groundwater from past herbicide applications at various substation sites. Once possible environmental impacts to groundwater and soils have been identified cleanup operations are initiated.

Accomplishments:
The Florida Department of Environmental Protection has issued a No Further Action (NFA) letter or Site Rehabilitation Completion Order for 95 sites.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $2,825,274

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.8

Title: State NPDES Administration

FPSC Approval: Order No. PSC-95-1051-FOF-EI

Description:
The State NPDES Administration fees are required by the State of Florida's National Pollutant Discharge Elimination System (NPDES) program administration. Annual and five-year permit renewal fees are required for the NPDES industrial wastewater permits at Plants Crist, Smith and Scholz.

Accomplishments:
Gulf has complied with the NPDES program administration fee submittal schedule.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $42,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.9

Title: Lead & Copper Rule

FPSC Approval: Order No. PSC-95-1051-FOF-EI

Description:
The Lead and Copper Rule expenses include potable water treatment and sampling costs as required by the Florida Department of Environmental Protection (FDEP) regulations.

Accomplishments:
Gulf has complied with all sampling and analytical protocols.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $4,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.10

Title: Environmental Auditing/Assessment

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Environmental Auditing/Assessment program ensures continued compliance with environmental laws, rules, and regulations through auditing and/or assessment of company facilities and operations.

Accomplishments:
Audits and assessments completed to date have demonstrated compliance with environmental laws, rules, and regulations.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $15,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.11

Title: General Solid and Hazardous Waste

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The General Solid and Hazardous Waste program provides for the proper identification, handling, storage, transportation and disposal of solid and hazardous wastes. This line item also includes O&M expenses associated with Gulf's Spill Prevention Control and Countermeasures (SPCC) plans.

Accomplishments:
Gulf has complied with all hazardous and solid waste regulations.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $1,000,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.12

Title: Above Ground Storage Tanks

FPSC Approval: Order No. PSC-97-1047-FOF-EI

Description:
The aboveground storage tank projects are required under the provisions of Chapter 62-762, F.A.C. which includes specific performance standards applicable to storage tank systems. These performance standards include maintenance requirements, installation of secondary containment and cathodic protection systems, as well as periodic tank integrity testing.

Accomplishments:
Gulf has complied with all applicable storage tank requirements.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $92,532

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

**Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.13**

Title: Low NO_x

FPSC Approval: Order No. PSC-98-0803-FOF-EI

Description:
The Low NO_x activity refers to the maintenance expenses associated with the Low NO_x burner tips on Crist Units 4 & 5 and Smith Unit 1.

Accomplishments:
Burner tips were installed on Plant Crist Units 4 & 5 and Plant Smith Unit 1. The Plant Smith Unit 1 Low NOx burners were retired in April 2016 when the unit ceased operations.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.14

Title: Ash Pond Diversion Curtains

FPSC Approval: Order No. PSC-98-1764-FOF-EI

Description:
The installation of flow diversion curtains in the Plant Crist industrial wastewater pond were required to effectively increase water retention time in the pond. Diversion curtains allow for the sedimentation/precipitation treatment process to be more effective in reducing levels of suspended particulate from the Plant Crist outfall.

Accomplishments:
Plant Crist replaced the diversion curtains and dredged the pond during the 2009-2010 timeframe.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.15

Title: Mercury Emissions

FPSC Approval: Order No. PSC-99-0912-FOF-EI

Description: The Mercury Emissions program pertains to requirements for Gulf to periodically analyze coal shipments for mercury and chlorine content. The Environmental Protection Agency (EPA) mandated that shipments of coal would be analyzed for mercury and chlorine only during 1999. No further notices of continued sampling requirements of coal shipments beyond 1999 have been issued by EPA, therefore, no expenses have been planned for this activity.

Accomplishments:
Coal shipments were analyzed as required during 1999. Sampling and analytical requirements are not expected during 2019.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.16

Title: Sodium Injection

FPSC Approval: Order No. PSC-99-1954-FOF-EI

Description:
This line item includes O&M expenses associated with the sodium injection system at Plant Crist. Sodium carbonate is added to the Plant Crist coal supply to enhance precipitator efficiencies when burning certain low sulfur coals.

Accomplishments:
Sodium carbonate injection is used at Plant Crist as necessary when low sulfur coal is burned.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $10,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

**Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.17**

Title: Gulf Coast Ozone Study (GCOS)

FPSC Approval: Order No. PSC-00-0476-FOF-EI

Description:
This project referred to Gulf's participation in the Gulf Coast Ozone Study (GCOS) which was a joint modeling analysis between Gulf Power and the State of Florida to provide an improved basis for assessment of eight-hour ozone air quality for Northwest Florida. The goal of the project was to develop strategies for ozone ambient air attainment to supplement the Florida Department of Environmental Protection (FDEP) studies submitted to the Environmental Protection Agency (EPA) for Escambia and Santa Rosa counties.

Accomplishments: The GCOS project was completed during 2006.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.18

Title: SPCC Substation Project

FPSC Approval: Order No. PSC-03-1348-FOF-EI

Description:
During 2002 EPA published a revision to Title 40 Code of Regulation Part 112, commonly referred to as the Spill Prevention Control and Countermeasures (SPCC) regulation. The revision expanded applicability of the rule to specifically include oil containing electrical transformers and regulators. Gulf was required to install additional containment and/or diversionary structures or equipment at several substations to prevent a potential discharge of oil to navigable waters of the United States or adjoining shorelines.

Accomplishments: Gulf has assessed its substations to determine which sites are subject to the revised SPCC regulations. Additional containment has been added to the substations that were identified as having a higher risk of discharging oil into navigable waters of the United States or adjoining shorelines.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.19

Title: FDEP NO_x Reduction Agreement

FPSC Approval: Order No. PSC-02-1396-FOF-EI

Description: This line item includes O&M expenses associated with the Crist Unit 7 SCR and the Crist Units 4 and 5 Selective Non-Catalytic Reduction (SNCR) projects that were included as part of the Florida Department of Environmental Protection (FDEP) and Gulf Power Agreement entered into on August 28, 2002 to address ozone attainment. Anhydrous ammonia, urea, air monitoring, catalyst regeneration, and general operation and maintenance expenses are included in this line item.

Accomplishments: The Crist Unit 7 SCR and the Crist Units 4 and 5 SNCRs are fully operational. The Crist Unit 6 SNCR was retired when the Crist Unit 6 SCR was placed in-service during the Spring of 2012. The Crist Unit 6 SCR was installed as part of the Air Quality Compliance Program.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $1,021,274

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.20

Title: Air Quality Compliance Program

FPSC Approval: **Order No. PSC-06-0972-FOF-EI**
Order No. PSC-13-0506-PAA-EI
Order No. PSC-17-0178-S-EI

Description: This line item covers prudently incurred costs for compliance with Gulf's Air Quality Compliance Program including expenses associated with Gulf's ownership portion of the Scherer 3 baghouse, SCR, and scrubber projects as well as associated equipment. More specifically, the line item includes the cost of anhydrous ammonia, hydrated lime, urea, limestone and general O&M expenses.

Accomplishments: The Plant Smith Unit 1 and Unit 2 SNCRs were placed in service during May 2009 and December 2008, respectively. The Smith SNCRs were retired in April 2016 after the coal units ceased operations. The Crist Units 4 -7 scrubber project was placed in-service December of 2009 and the Crist Unit 6 hydrated lime injection system was placed in-service in 2011. The Plant Crist Unit 6 SCR was placed-in-service in April of 2012. The Plant Daniel scrubbers were placed in-service in November 2015. The Plant Daniel Bromine and Activated Carbon Injection systems were placed in-service in December 2015. This line items includes expenses associated with a baghouse, SCR, and scrubber as well as associated equipment installed at Plant Scherer 3. Plant Scherer 3 baghouse was placed in-service February 2009, SCR in-service December 2010, and scrubber in-service March 2011.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $21,813,790

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.21

Title: Maximum Achievable Control Technology (MACT)
Information Collection Request (ICR)

FPSC Approval: Order No. PSC-09-0759-FOF-EI

Description: During early 2010 EPA finalized an extensive Information Collection Request (ICR) for coal and oil fired steam electric generating units to support Maximum Achievable Control Technology (MACT) rulemaking under Section 112 of the Clean Air Act (CAA). The ICR required submission of information on control equipment efficiencies, emissions, capital and O&M costs, and fuel data for all coal and oil fired generating units greater than 25 MW.

Accomplishments:
Gulf completed the Part I & 2 MACT ICR survey and the Part 3 emissions testing reports during 2010.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

**Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.22**

Title: Crist Water Conservation

FPSC Approval: Order No. PSC-08-0775-FOF-EI

Description: Gulf Power entered into an agreement with the Emerald Coast Utilities Authority (ECUA) to begin utilizing reclaimed water to reduce the demand for groundwater and surface water withdrawals. This line item includes general O&M expenses associated with the Plant Crist reclaimed water system such as piping, pump, and valve maintenances.

Accomplishments:
Gulf began receiving reclaimed water from ECUA during November 2010.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $428,542

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

**Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.23**

Title: Coal Combustion Residuals

FPSC Approval: PSC-15-0536-FOF-EI

Description: The Coal Combustion Residuals (CCR) program includes expenses related to the regulation of Coal Combustion Residuals by the United States Environmental Protection Agency ("EPA") and the Florida Department of Environmental Protection ("FDEP"). On April 17, 2015 EPA published the final CCR rule in the Federal register regulating CCR disposal under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The CCR rule is located in Title 40 Code of Federal Regulations (CFR) Parts 257 and 261. The CCR rule regulates the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste at active generating power plants. The rule applies to CCR Units at Gulf's Plants Crist, Scherer, Smith, and Daniel. Plant Scherer is also regulated under Georgia's Environmental Protection Division CCR Rule, which requires permit applications to be submitted for the facility's ash pond and CCR landfill by November 22, 2019.

In addition, pursuant to its authority granted under the Clean Water Act, the FDEP issues National Pollutant Discharge Elimination System (NPDES) industrial wastewater permits for each of Gulf's generating facilities. A NPDES permit renewal for Plant Scholz (FL0002283) was issued on October 20, 2015 which requires closure of the existing on-site ash pond during the 2015-2020 permit cycle.

Accomplishments:
During 2015 Gulf established a publicly available website, began conducting and documenting weekly and monthly inspections, and prepared a fugitive dust plan as required by the CCR rule. Gulf also installed permanent markers at all CCR ponds and conducted annual inspections of the CCR impoundments and landfills. In 2017, Gulf completed construction of the Plant Scholz slurry wall, industrial wastewater pond, and supporting activities to facilitate closure. In 2018, Gulf moved forward with the Smith and Scholz ash pond closure projects which includes removing CCR material from portions of the existing ponds, and transferring CCR material to a dry stack area within the footprint of the pond.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $3,229,639.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.24

Title: Smith Water Conservation

FPSC Approval: Order No. PSC-09-0759-FOF-EI

Description: Specific Condition Nine of the Northwest Florida Water Management District (NFWMD) Individual Water Use Permit Number 19850773 (Permit) issued on November 30, 2006, requires Gulf's Plant Smith to implement measures to increase water conservation and efficiency. On October 20, 2008, the NWFMD issued a letter stating that the re-use of reclaimed water meets the requirement listed in Specific Condition Nine in the Permit. This line item includes general O&M expenses associated with the Plant Smith reclaimed water system such as sampling and analytical charges, and mechanical integrity testing expenses required by the FDEP permit.

Fiscal Expenditures: N/A

Progress Summary: Gulf has installed three deep injection wells, a pump station and associated piping

Projections: $190,000

FEDERAL REGISTER

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No. 158 August 15, 2014

Part II

Environmental Protection Agency

40 CFR Parts 122 and 125
National Pollutant Discharge Elimination System—Final Regulations To Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 122 and 125

[EPA–HQ–OW–2008–0667, FRL–9817–3]

RIN 2040–AE95

National Pollutant Discharge Elimination System—Final Regulations To Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The purpose of this action is to reduce impingement and entrainment of fish and other aquatic organisms at cooling water intake structures used by certain existing power generation and manufacturing facilities for the withdrawal of cooling water from waters of the United States. This rule establishes requirements under section 316(b) of the Clean Water Act (CWA) for existing power generating facilities and existing manufacturing and industrial facilities that are designed to withdraw more than 2 million gallons per day (mgd) of water from waters of the United States and use at least 25 percent of the water they withdraw exclusively for cooling purposes. These national requirements, which will be implemented through National Pollutant Discharge Elimination System (NPDES) permits, apply to the location, design, construction, and capacity of cooling water intake structures (CWIS) at regulated facilities and provide requirements that reflect the best technology available (BTA) for minimizing adverse environmental impact. On April 20, 2011, EPA published a proposed rule that included several options for addressing these impacts. Subsequently, EPA published two Notices of Data Availability (NODA), on June 11, 2012 and June 12, 2012, that further clarified EPA's proposed approach. This final rule also responds to judicial remand of aspects of the previously promulgated Phase II and Phase III section 316(b) rules. In addition, EPA is also responding to an earlier judicial decision by removing from the previously promulgated Phase I new facility rule a restoration-based compliance alternative and the associated monitoring and demonstration requirements.

DATES: This regulation is effective October 14, 2014. For judicial review purposes, this final rule is promulgated as of 1 p.m. EDT (Eastern Daylight Time) on August 29, 2014 as provided in 40 CFR 23.2.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–HQ–OW–2008–0667. All documents in the docket are listed on the *www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, e.g., CBI (confidential business information) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hardcopy form. Publicly available docket materials are available either electronically through *www.regulations.gov* or in hardcopy at the Water Docket in the EPA Docket Center, EPA/DC, EPA West, Room 3334, 1301 Constitution Avenue NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is 202–566–1744, and the telephone number for the Water Docket is 202–566–2426.

FOR FURTHER INFORMATION CONTACT: For additional biological information, contact Tom Born at 202–566–1001; email: *born.tom@epa.gov*. For additional economic information, contact Wendy Hoffman at 202–564–8794; email: *hoffman.wendy@epa.gov*. For additional technical information, contact Paul Shriner at 202–566–1076; email: *shriner.paul@epa.gov*.

SUPPLEMENTARY INFORMATION:

What facilities are regulated by this action?

This final rule applies to existing facilities that use cooling water intake structures to withdraw water from waters of the United States and have or require an NPDES (National Pollutant Discharge Elimination System) permit issued under section 402 of the CWA (Clean Water Act). Existing facilities subject to this regulation include those with a design intake flow (DIF) greater than 2 mgd. If a facility meets these conditions, it is subject to today's final regulations. If a facility has or requires an NPDES permit but does not meet the 2 mgd intake flow threshold, it is subject to permit conditions implementing CWA section 316(b), developed by the NPDES Permit Director on a case-by-case basis using BPJ (best professional judgment) under 40 CFR 125.90(b). This final rule defines the term *cooling water intake structure* to mean the total physical structure and any associated constructed waterways used to withdraw cooling water from waters of the United States. The cooling water intake structure extends from the point at which water is first withdrawn from waters of the United States source up to, and including, the intake pumps. Generally, facilities that meet these criteria fall into two major groups: steam electric generating facilities and manufacturing facilities. The final rule also makes limited changes to the requirements for Phase I facilities (i.e., new facilities).

Exhibit 1 lists industry sectors of facilities subject to this final rule. This table is not intended to be exhaustive; facilities in other industries not listed in Exhibit 1 could also be regulated. The 4-digit NAICS industry sectors may include 6-digit NAICS industry sub-sectors with operations that are not dependent on cooling water.

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EXHIBIT 1—INDUSTRY SECTORS WITH FACILITIES SUBJECT TO THE FINAL RULE

Category	4-Digit NAICS industry sectors	NAICS definition
Federal, State and Local Government	Electric Power Industry	
	2211	Electric Power Generation, Transmission and Distribution.
Industry	Electric Power Industry	
	2211	Electric Power Generation, Transmission and Distribution.
Industry	Primary Manufacturing Industries	
	3112	Grain and Oilseed Milling.
	3113	Sugar and Confectionery Product Manufacturing.
	3121	Beverage Manufacturing.
	3221	Pulp, Paper, and Paperboard Mills.
	3222	Converted Paper Product Manufacturing.
	3241	Petroleum and Coal Products Manufacturing.
	3251	Basic Chemical Manufacturing.
	3252	Resin, Synthetic Rubber, and Artificial Synthetic Fibers and Filaments Manufacturing.
	3253	Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing.
	3254	Pharmaceutical and Medicine Manufacturing.
	3256	Soap, Cleaning Compound, and Toilet Preparation Manufacturing.
	3259	Other Chemical Product and Preparation Manufacturing.
	3311	Iron and Steel Mills and Ferroalloy Manufacturing.
	3312	Steel Product Manufacturing from Purchased Steel.
	3313	Alumina and Aluminum Production and Processing.
Industry	Other Industries	
	1119	Other Crop Farming.
	2122	Metal Ore Mining.
	3133	Textile and Fabric Finishing and Fabric Coating Mills.
	3211	Sawmills and Wood Preservation.
	3314	Nonferrous Metal (except Aluminum) Production and Processing.
	3322	Cutlery and Handtool Manufacturing.
	3329	Other Fabricated Metal Product Manufacturing.
	3364	Aerospace Product and Parts Manufacturing.
	3391	Medical Equipment and Supplies Manufacturing.

To determine whether a facility could be regulated by this action, one should carefully examine the applicability criteria in § 125.91 of the final rule. For information regarding the applicability of this action to an entity, consult the persons listed for technical information in **FOR FURTHER INFORMATION CONTACT**.

Supporting Documentation

1. Docket

EPA has established an official public docket for this action under Docket ID EPA–HQ–OW–2008–0667. The official public docket consists of the documents specifically referenced in this action, any public comments received, and other information related to this action. Although a part of the official docket, the public docket does not include information claimed as Confidential Business Information (CBI) or other information, the disclosure of which, is restricted by statute. For information on how to access materials in the docket, see **ADDRESSES** above. To view docket materials, call ahead to schedule an appointment. Every user is entitled to copy 266 pages per day before incurring a charge. The Docket Center may charge $0.15 for each page over the 266-page limit, plus an administrative fee of $25.00.

2. Electronic Access

You may access this **Federal Register** document and the docket electronically through the Web site *http://www.regulations.gov* by searching for Docket ID EPA–HQ–OW–2008–0667. For additional information about the public docket, visit the EPA Docket Center home page at *http://www.epa.gov/epahome/dockets.htm*.

3. Technical Support Documents

The final regulation is supported by three major documents:

- Economic Analysis for the Final Section 316(b) Existing Facilities Rule (EPA–821–R–14–001), referred to as the EA throughout. This document presents the analysis of compliance costs, economic impacts, energy supply effects, and a summary of benefits associated with the final rule.
- Benefits Analysis for the Final Section 316(b) Existing Facilities Rule (EPA–821–R–14–005), referred to as the BA throughout. This document examines cooling water intake structure impacts and regulatory benefits at the regional and national levels.
- Technical Development Document for the Final Section 316(b) Existing Facilities Rule (EPA–821–R–14–002), referred to as the TDD throughout. This document presents detailed information on the methods used to develop unit costs and describes the set of technologies that may be used to meet the final rule requirements.

Table of Contents

I. Executive Summary and Scope of Today's Rulemaking

A. Executive Summary

1. Summary of the Major Provisions of the Regulatory Action

This rule establishes requirements under section 316(b) of the Clean Water Act (CWA) for existing power generating facilities and existing manufacturing and industrial facilities that withdraw more than 2 million gallons per day (mgd) of water from waters of the United States and use at least 25 percent of the water they withdraw exclusively for cooling purposes. These national requirements, which will be implemented through National Pollutant Discharge Elimination System (NPDES) permits, apply to the location, design, construction, and capacity of cooling water intake structures (CWIS) at regulated facilities by setting requirements that reflect the best technology available (BTA) for minimizing adverse environmental impact.[1] On April 20, 2011, EPA published a proposed rule that included several options for addressing these impacts. EPA published two Notices of Data Availability (NODA), on June 11, 2012 and June 12, 2012, that further clarified EPA's approach. This final rule constitutes EPA's response to the remand of the Phase II and Phase III rules. In addition, EPA is also responding to the decision in *Riverkeeper I* to remove from the Phase I new facility rule the restoration-based compliance alternative and the associated monitoring and demonstration requirements.

2. Need for the Rule

Cooling water is withdrawn for the purpose of dissipating waste heat from industrial processes. Over half of all water withdrawn in the United States each year is for cooling purposes. By far, the largest industrial use of cooling water is for thermoelectric generation, but cooling water is also used in the manufacture of aluminum, chemicals and allied products, food and kindred products, pulp and paper, refined petroleum products, and steel, as well as in other industries. Although newer designs are more efficient, the long life of the capital equipment in these industries suggests that the adverse environmental impacts could continue for decades. Electric generators, for

[1] As noted here, the term BTA means ''best technology available for minimizing adverse environmental impact.'' In the interests of brevity, the acronym will frequently be used in the preamble to reflect the entire definition.

example, typically convert 30 to 40 percent of the heat content of their fuel to electricity, depending on their fuel source, age of their facility, and capacity utilization (see TDD 5.1). The purpose of cooling water withdrawals is to dissipate that portion of the heat that is a by-product of industrial processes that facilities have not used and therefore view as waste heat.

The withdrawal of cooling water by existing facilities removes and kills hundreds of billions of aquatic organisms from waters of the United States each year, including plankton (small aquatic animals, including fish eggs and larvae), fish, crustaceans, shellfish, sea turtles, marine mammals, and many other forms of aquatic life. Most impacts are to early life stages of fish and shellfish. Aquatic organisms drawn into CWIS are either impinged (I) on components of the intake structure or entrained (E) in the cooling water system itself. In CWA section 316(b) and in this rulemaking, these impacts are referred to as *adverse environmental impact* (AEI). Rates of I&E depend on species characteristics, the facility's environmental setting, and the location, design, construction and capacity of the facility's CWIS. In addition to direct losses of aquatic organisms from I&E, a number of indirect, ecosystem-level effects may also occur, including (1) disruption of aquatic food webs resulting from the loss of impinged and entrained organisms that provide food for other species, (2) disruption of nutrient cycling and other biochemical processes, (3) alteration of species composition and overall levels of biodiversity, and (4) degradation of the overall aquatic environment. In addition to the impacts of a single CWIS on currents and other local habitat features, environmental degradation can result from the cumulative impact of multiple intake structures operating in the same watershed or intakes located within an area where intake effects interact with other environmental stressors. Finally, although it is difficult to measure, the compensatory ability of an aquatic population, which is the capacity for a species to increase survival, growth, or reproduction rates in response to decreased population, is likely compromised by I&E and the cumulative impact of other stressors in the environment over extended periods of time.

The beneficiaries of fish protection at cooling water intakes include fisherman, both recreational and commercial, and people interested in well-functioning and healthy aquatic ecosystems. While most people consume electricity, they consume electricity in differing amounts, and may not be uniformly interested in, or willing to pay for, fish protection. Thus, there is imperfect overlap between those who could be required to pay for fish protection and those who would benefit from fish protection. Those who desire more fish protection have extremely limited opportunities in which they can express their willingness to pay for fish protection in market transactions that result in fish protection. In addition, deregulation in the electric industry has made it more difficult for merchant power producers to both remain competitive and pass along to consumers costs associated with fish protection, relative to rate-regulated electric utilities that are vertically integrated.

Fish protection at cooling water intakes is also variable, based on species and their migrations, waterbody, size of a cooling water intake, presence of multiple facilities on a waterbody, and many more variables that are highly site specific. In addition, given the history of litigation around this section of the Clean Water Act, states have, in some instances, administratively continued permits while awaiting final Federal action, and thus fish protection has been delayed, in some instances for decades.

Promulgation of today's final rule will complete EPA's regulations under section 316(b) of the Clean Water Act. This rule includes a national performance standard as the BTA to address impingement mortality (IM) at existing CWIS. This national standard for impingement reflects EPA's assessment that impingement reduction technology is available, feasible and demonstrated, and thus BTA for existing facilities. The impingement mortality standard is based on modified traveling screens with fish returns and includes a performance standard as one compliance alternative, but also offers six other compliance alternatives that are equivalent or better in performance. With regard to entrainment, this rule contains a national BTA standard that is a process for a site-specific determination of entrainment mitigation requirements at existing CWIS. The entrainment provision reflects EPA's assessment that there is no single technology basis that is BTA for entrainment at existing facilities, but instead a number of factors that are best accounted for on a site-specific basis. Site-specific decision making may lead to a determination by the NPDES permitting authority that entrainment requirements should be based on variable speed pumps, water reuse, fine mesh screens, a closed-cycle recirculating system, or some combination of technologies that constitutes BTA for the individual site. The site-specific decision-making may also lead to no additional technologies being required.

In addition to the above provisions, which apply to existing units at existing facilities, the rule establishes a BTA standard, for both impingement mortality and entrainment, for new units at existing facilities. Under this standard, new units at existing facilities will be subject to requirements similar to the section 316(b) requirements for new facilities subject to the previously promulgated Phase I rule.

In addition, there is a need to regulate even those facilities that adopt the most effective technology. Closed-cycle cooling is a technology that recirculates cooling water, reducing withdrawals from surface waters. Closed-cycle cooling can reduce water withdrawals by at least 95 percent, compared to once-through cooling, but is itself capital intensive. Facilities that retrofit to closed-cycle cooling without also modifying their condenser may not be able to operate at full capacity during summer peak periods of electricity demand (replacing the condenser would require longer outages). Operators who retrofit closed-cycle cooling systems have a financial incentive not to run their system in closed-cycle mode during summer months. Thus, decision making at facilities that use cooling water may not take society's preferences for fish protection into account in their actions.

EPA notes that some facilities have installed, and some NPDES permits require, controls that protect aquatic organisms from impingement and entrainment. Facilities may have adopted controls as good stewards. Directors may have required controls to meet state water quality standards, particularly with regard to temperature. Based on our evaluation of available evidence, these actions have not been widespread enough to discourage cooling water withdrawals from waters where they have the greatest impact on aquatic organisms.

3. Costs and Benefits

As presented in Exhibit I–1, EPA assessed the expected costs to society for complying with the final rule, accounting for both the existing CWIS unit provision and the new unit provision, as $275 million and $297 million per year at the 3 percent and 7 percent discount rates, respectively. These costs reflect permit applications, studies, recordkeeping, monitoring, and reporting required by the rule. The costs also include costs of technologies for complying with the BTA for IM. The cost of additional technologies that may be required to meet the site-specific BTA for entrainment are not included in this analysis because, as explained in Section VII, EPA cannot estimate, with any level of certainty, what site-specific determinations will be made based on the analyses that will be generated as a result of the national BTA standard for entrainment decision-making established by today's rule.

EPA estimates that today's final rule—including standards for both existing units and new units at existing facilities—will achieve monetized benefits to society of $33 million and $29 million annually, again depending on the discount rate. This estimate of benefits omits important categories of benefits that EPA expects the rule will achieve, such as most of the benefits associated with fish other than commercially and recreationally harvested fish. As a result, these estimates are likely to understate substantially the rule's expected benefits to society. In estimating the benefits of today's rule, EPA did not rely on the results of the stated preference survey conducted by the Agency and described in the June 12, 2012 Notice of Data Availability (77 FR 34927 (June 12, 2012)). Included in the monetized benefits is EPA's estimate that the final rule will reduce greenhouse gas (GHG) emissions by 9.3 million tons of CO_2-equivalent emissions over the 40-year compliance period for this analysis. Based on this reduction in GHG emissions, EPA estimates benefits to society (based on social cost of carbon (DCN [2] 12–4853)) ranging from $12 million to $13 million annually (see Section 9 of the BA), depending on the discount rate and other assumptions in the social cost of carbon analysis.

EXHIBIT I–1—TOTAL ANNUALIZED SOCIAL COSTS AND BENEFITS FOR THE FINAL RULE
[in millions, 2011 dollars]

	Existing units	New units	Total
Using 3 percent discount rate:			
Social Costs	$272.4	$2.5	$274.9
Social Benefits	33.0	−0.2	32.8
Using 7 percent discount rate:			
Social Costs	295.3	2.0	297.3
Social Benefits	28.7	−0.1	28.6

EPA expects that the final rule will have relatively minor economic impacts on the regulated facilities, the entities that own them, and the overall electric power sector, which is the industry most affected by today's rule. Under the rule's existing unit provisions, EPA estimates that a substantial majority (86 percent) of electric generators will incur compliance costs of less than 1 percent of revenue, indicating the minor impact of the rule on these facilities.

EPA also expects very small impacts on the non-power sector component of regulated facilities. EPA estimates that 504 out of 509 facilities will incur costs less than one percent of revenue, five will incur costs between one and three percent, and none will incur costs greater than 3 percent. In addition, EPA estimates that no manufacturing facilities will close as a result of today's rule, and that only 12 facilities in the non-power sector component will experience moderate financial stress short of closure. These 12 facilities represent approximately 3 percent of the estimated total regulated facilities in the non-power sector component.

At the level of the entities that own regulated facilities, EPA estimates that 91 to 94 percent of entities owning regulated facilities in the electric power sector will incur compliance costs of less than 1 percent of revenue under the rule's existing unit provisions. Likewise, for the non-power sector component of regulated facilities, EPA estimates that 90 to 95 percent of entities owning regulated facilities will incur compliance costs of less than 1 percent of revenue under the rule's existing unit provisions.

Finally, EPA estimates that today's rule will have a minor impact on the overall electric power sector and electricity consumers. EPA estimates that the rule will not affect national or regional electricity markets on a long-term basis. In addition, EPA expects there to be no effects of the final rule on the reliability of electricity generation, transmission and distribution. In terms of consumer impacts, EPA estimates, on average, across the United States, that the final rule will increase electricity production costs by 0.009 cents per kWh, causing an estimated 0.1 percent increase in average electricity prices. The corresponding annual increase in electricity costs is approximately $1.03 per household.

B. Scope of Today's Rulemaking

Today's final rule represents the last stage in EPA's efforts to implement section 316(b) of the CWA. In the course of their operations, electric power facilities and certain manufacturing facilities use large amounts of water either for cooling purposes or in their manufacturing processes. Such facilities typically remove water from nearby sources using ''cooling water intake structures.'' The structures associated with water removal pose a number of threats to the environment. Principally, aquatic organisms are squashed against intake screens—impingement—or drawn into the cooling system—entrainment. Section 316(b) requires EPA to develop standards for cooling water intakes structures.

Today's final rule establishes national requirements applicable to the location, design, construction, and capacity of cooling water intake structures at existing facilities that reflect the BTA for minimizing the adverse environmental impacts– impingement and entrainment—associated with the use of these structures. It represents the culmination of EPA's efforts to implement section 316(b) and, as such, fulfills EPA's obligation under a settlement agreement entered in the United States District Court for the Southern District of New York in *Riverkeeper Inc., et al.* v. *Jackson,* No. 93 Civ. 0314 (AGS). (For a more detailed discussion of the settlement agreement, see Section II.C.)

This final rule establishes requirements for all existing facilities with a DIF (design intake flow) of more

[2] DCN refers to a document control number. An index of DCNs can be found in the docket for this action.

than 2 mgd. EPA estimates that a total of 1,065 facilities will be subject to the final rule, including 544 Electric Generators, 509 Manufacturers in six Primary Manufacturing Industries, and 12 Manufacturers in Other Industries. The rule also clarifies the definition and requirements for new units at existing facilities. The applicable requirements are summarized in Exhibits I–2 and I–3.

EXHIBIT I–2—APPLICABILITY BY PHASE OF THE 316(B) RULES

Facility characteristic	Applicable rule
New power-generating or manufacturing facility	Phase I rule.
New offshore oil and gas facility	Phase III rule.
New unit at an existing power-generating or manufacturing facility	This rule.
Existing power-generating or manufacturing facility	This rule.
Existing offshore oil and gas facility and offshore seafood processing facilities	This rule (site-specific, BPJ).

EXHIBIT I–3—APPLICABLE REQUIREMENTS OF TODAY'S RULE FOR EXISTING FACILITIES

Facility characteristic	Applicable requirements
Existing facility with a DIF greater than 2 mgd and an AIF (actual intake flow) greater than 125 mgd.	Impingement mortality standards at § 125.94(c) and site-specific entrainment requirements under the entrainment standards at § 125.94(d) (Additional study requirements at § 122.21(r)(1)(ii)(B)).
Existing facility with a DIF greater than 2 mgd but AIF not greater than 125 mgd.	Impingement mortality standards at § 125.94(c) and site-specific entrainment requirements under the entrainment standards at § 125.94(d).
New unit at an existing facility where the facility has a DIF greater than 2 mgd.	Impingement mortality and entrainment standards for new units at § 125.94(e).
Other existing facility with a DIF of 2 mgd or smaller or that has an intake structure that withdraws less than 25 percent of the water for cooling purposes on an actual intake flow basis.	Case-by-case BPJ permitting per § 125.90(b).

At an early stage in the development of section 316(b) requirements, EPA divided its rulemaking effort into three phases. The first addressed new facilities, the second, large existing electricity utility facilities and the third, the remaining electric generating facilities not addressed in the earlier phases as well as existing manufacturing operations. As EPA's analysis progressed, however, it became clear that it could address in one rulemaking cooling water intake structures at both existing steam electric generating and manufacturing facilities. From a biological perspective, the effect of intake structures on impingement and entrainment [3] does not differ depending on whether an intake structure is associated with a power plant or a manufacturer. In 2009, following judicial challenge of the Phase II rule, EPA asked the U.S. Court of Appeals for the Second Circuit to remand the rule to the Agency for further action consistent with a decision by the U.S. Supreme Court in *Entergy Corp.* v. *Riverkeeper, Inc.* and the Second Circuit's decision on the Phase II rule in *Riverkeeper, Inc.* v. *EPA,* 475 F.3d 83 (2d cir. 2007). In 2009, EPA also asked the U.S. Court of Appeals for the Fifth Circuit to remand certain aspects of EPA's Phase III rule that were before it in a petition for review. Today's rule responds to these remands as well to the Second Circuit's remand of limited aspects of the Phase I section 316(b) rule in *Riverkeeper Inc.* v. *Johnson,* 358 F.3d 174 (2nd Cir. 2004). EPA has here consolidated the universe of potentially regulated facilities from the remanded 2004 Phase II rule with the existing facilities in the remanded 2006 Phase III rule for establishing requirements in a single proceeding.

C. General Applicability

This rule applies to owners and operators of existing facilities [4] that meet all following criteria:

- The facility is a point source that uses or, in the case of new units at an existing facility, proposes to use cooling water from one or more cooling water intake structures, including a cooling water intake structure operated by an independent supplier not otherwise subject to 316(b) requirements that withdraws water from waters of the United States and provides cooling water to the facility by any sort of contract or other arrangement;
- The facility-wide DIF for all cooling water intake structures at the facility is greater than 2 mgd;
- The cooling water intake structure withdraws cooling water from waters of the United States; and
- At least 25 percent of the water actually withdrawn—actual intake flow (AIF)—is used exclusively for cooling purposes.

A facility may choose to demonstrate compliance with the final rule for the entire facility, or for each individual cooling water intake structure.

EPA is adopting provisions that promote the reuse of water from certain sources for cooling and that ensure that the rule does not discourage the reuse of cooling water for other uses such as process water. For example, the final rule at § 125.91(c) specifies that obtaining cooling water from a public water system, using reclaimed water from wastewater treatment facilities or desalination plants, or recycling treated process wastewater effluent (such as wastewater treatment plant ''gray'' water) does not constitute use of a cooling water intake structure for purposes of this rule. In addition, the definition of cooling water at § 125.92 provides that cooling water obtained from a public water system, reclaimed water from wastewater treatment facilities or desalination plants, treated effluent from a manufacturing facility, or cooling water that is used in a manufacturing process either before or

[3] Throughout the preamble and support documents, the terms ''entrainment'' and ''entrainment mortality'' may be used interchangeably. As described below, EPA continues to assume that, in most instances, entrainment mortality is 100 percent, leaving little distinction between the two terms.

[4] Throughout the preamble, the terms ''owner or operator of a facility'' and ''facility'' may be used interchangeably. In cases where the preamble may state that a facility is required to do a given activity, it should be interpreted as the owner or operator of the facility is required to do the activity.

after it is used for cooling as process water is not considered cooling water for the purposes of calculating the percentage of a facility's intake flow that is used for cooling purposes. Therefore, water used for both cooling and non-cooling purposes does not count toward the 25 percent threshold. Examples of water withdrawn for non-cooling purposes includes water withdrawn for warming by LNG (liquefied natural gas) facilities and water withdrawn for public water systems by desalinization facilities.

Today's rule focuses on those facilities that are significant users of cooling water. The rule provides that only those facilities that use 25 percent or more of the water withdrawn exclusively for cooling purposes (on an actual intake flow basis) are subject to the rule. EPA previously considered a number of cut-points or approaches for focusing the applicability of the rule (66 FR 28854, May 25, 2001 and 66 FR 65288, December 18, 2001). EPA used the 25 percent threshold in each of the Phase I, II, and III rules. For this rule, EPA did not receive any new data supporting a different threshold or identify new approaches to the applicability of the rule. Consequently, EPA is adopting 25 percent as the threshold for the percent of flow used for cooling purposes to ensure that a large majority of cooling water withdrawn from waters of the United States are subject to the rule's requirements for minimizing adverse environmental impact. Because power-generating facilities typically use far more than 25 percent of the water they withdraw exclusively for cooling purposes, the 25 percent threshold will ensure that intake structures accounting for nearly all cooling water used by the power sector are addressed by today's rule requirements. While manufacturing facilities often withdraw water for more purposes than cooling, the majority of the water is withdrawn from a single intake structure. Once water passes through the intake, water can be apportioned to any desired use, including uses that are not related to cooling. However, as long as at least 25 percent of the water is used exclusively for cooling purposes, the intake is subject to the requirements of today's rule. EPA estimates that approximately 70 percent of manufacturers and 87 percent of power-generating facilities that meet the first three criteria for applicability outlined above also use 25 percent or more of intake water for cooling and thus are subject to today's rule. (See 66 FR 65288, December 18, 2001.)

For facilities that are below any of the applicability thresholds in today's rule—for example, a facility that withdraws less than 25 percent of the intake flow for cooling purposes—the Director must set appropriate requirements on a case-by-case basis, using BPJ, based on § 125.90(b). Today's rule is not intended to constrain permit writers at the Federal, State, or Tribal level, from addressing such cooling water intake structures. Also, EPA decided to adopt for the final rule the proposed provision that requires the owners and operators for certain categories of facilities (existing offshore oil and gas facilities, existing offshore seafood processing facilities and offshore LNG terminals) to meet case-by-case BTA impingement and entrainment requirements, established by the Director. Such facilities are subject to permit conditions implementing CWA section 316(b) if the facility is a point source that uses a cooling water intake structure and has, or is required to have, an NPDES permit.

D. What is an ''existing facility'' for purposes of the final rule?

In today's rule, EPA is defining the term ''existing facility'' to include any facility subject to section 316(b) that is not a ''new facility'' as defined in 40 CFR 125.83 (the Phase I rule).

A point source discharger would be subject to Phase I or today's rule even if the cooling water intake structure it uses is not located at the facility.[5] In addition, modifications or additions to the cooling water intake structure (or even the total replacement of an existing cooling water intake structure with a new one) does not convert an otherwise unchanged existing facility into a new facility, regardless of the purpose of such changes (e.g., to comply with today's rule or to increase capacity). Rather, the determination as to whether a facility is new (Phase I) or existing (today's rule) focuses on whether or not it is a greenfield or stand-alone facility whose processes are substantially independent of an existing facility, and whether or not there are changes to the cooling water intake. New facility does not include new units that are added to a facility for purposes of the same general industrial operation. For example, a new peaking unit at an existing electrical generating station is not a new facility (40 CFR 125.83). The distinction between an existing facility and a new facility is separate from the distinction between an existing unit at an existing facility and a new unit at an existing facility, which is discussed at greater length in Section J below.

E. What is ''cooling water'' and what is a ''cooling water intake structure?''

EPA has slightly revised the definition of *cooling water intake structure* from proposal for today's rule. In today's final rule, a cooling water intake structure is defined as the total physical structure and any associated constructed waterways used to withdraw cooling water from waters of the United States. Under the definition in today's rule, the cooling water intake structure extends from the point at which water is first withdrawn from Waters of the United States up to, and including, the intake pumps. The final rule at § 125.91(c) also specifies that obtaining cooling water from a public water system, using reclaimed water from wastewater treatment facilities (such as wastewater treatment plant ''gray'' water) or desalination plants, or recycling treated process wastewater effluent does not constitute use of a cooling water intake structure for purposes of applicability of this rule. As a point of clarification, facilities subject to today's rule may choose to use another entity's treated wastewater as a source of cooling water, thereby reducing cooling water withdrawals and associated impingement and entrainment. EPA notes that because the entity providing the wastewater for cooling has already treated it to meet any applicable discharge requirements (e.g., otherwise applicable effluent limitations guidelines and standards, water quality standards, etc.), EPA is not concerned that this provision will lead to pollutant discharges that would not have occurred if the treated effluent had been discharged by the other entity.

Today's rule adopts the new facility rule's definition of *cooling water* as water used for contact or noncontact cooling, including water used for equipment cooling, evaporative cooling tower makeup, and dilution of effluent heat content. The definition specifies that the intended use of cooling water is to absorb waste heat [not being efficiently used or recaptured for production and thus] rejected from the process or processes used or from auxiliary operations on the facility's premises. The definition also indicates that cooling water obtained from a public water system, reclaimed water from wastewater treatment facilities or desalination plants, treated effluent from a manufacturing facility, or cooling water that is used in a manufacturing process either before or after it is used for cooling as process water would not

[5] For example, a facility might purchase its cooling water from a nearby facility that owns and operates a cooling water intake structure.

be considered cooling water for the purposes of determining whether 25 percent or more of the actual intake flow is cooling water. This clarification is necessary because cooling water intake structures typically bring water into a facility for numerous purposes, including industrial processes; use as circulating water, service water, or evaporative cooling tower makeup water; dilution of effluent heat content; equipment cooling; and air conditioning. Note, however, that all intake water (including cooling and non-cooling process) is included in the determination as to whether the 2 mgd DIF threshold for covered intake structures is met.

F. Would my facility be covered only if it is a point source discharger?

Today's rule applies only to facilities that have an NPDES permit or are required to obtain one. This is the same requirement EPA included in the Phase I new facility rule at § 125.81(a)(1). Requirements for complying with CWA section 316(b) will continue to be applied through NPDES permits.

On the basis of the Agency's review of potential existing facilities that employ cooling water intake structures, the Agency anticipates that most facilities will control the intake structure that supplies them with cooling water, and discharge some combination of their cooling water, wastewater, or stormwater to a water of the United States through a point source regulated by an NPDES permit. In such cases, the facility's NPDES permit must include the requirements for the cooling water intake structure. If an existing facility's only NPDES permit is a general permit for stormwater discharges, the Agency anticipates that the Director will write an individual NPDES permit containing requirements for the facility's cooling water intake structure. Alternatively, requirements applicable to cooling water intake structures could be incorporated into general permits. If requirements are placed into a general permit, they must meet the requirements set out at 40 CFR 122.28.

As EPA stated in the preamble to the final Phase I rule (66 FR 65256, December 18, 2001), the Agency encourages the Director to closely examine scenarios in which a facility withdraws significant amounts of cooling water from waters of the United States but is not required to obtain an NPDES permit. As appropriate, the Director must apply other legal requirements, where applicable, such as CWA sections 401 or 404, the Coastal Zone Management Act, the National Environmental Policy Act, the Endangered Species Act, or similar State or Tribal authorities to address adverse environmental impact caused by cooling water intake structures at those facilities.

G. Would my facility be covered if it withdraws water from waters of the united states? what if my facility obtains cooling water from an independent supplier?

The requirements in today's rule apply to cooling water intake structures that have the design capacity to withdraw amounts of water greater than 2 mgd from waters of the United States. Waters of the United States include the broad range of surface waters that meet the regulatory definition at 40 CFR 122.2 and 40 CFR 230.3, which includes lakes, ponds, reservoirs, nontidal rivers or streams, tidal rivers, estuaries, fjords, oceans, bays, and coves. These potential sources of cooling water can be adversely affected by impingement and entrainment.

Some facilities use an impoundment such as a man-made pond or reservoir as part of a cooling system. Cooling water is withdrawn from the pond or reservoir at one point and heated water is discharged to a different point, using mixing and evaporative processes. As explained above, section 316(b) and today's final rule apply only to withdrawals of cooling water from waters of the United States; accordingly, to the extent a facility withdraws cooling water from a pond or reservoir that is not itself a water of the United States and does not withdraw any make-up water from waters of the U.S., the requirements of today's rule do not apply to such systems. Impoundments that are not constructed from a waters of the U.S. but do withdraw make-up water from waters of the U.S. can be closed-cycle recirculating systems subject to the requirements of today's rule, provided that withdrawal for make-up water is minimized.

Facilities that withdraw cooling water from impoundments that are in whole or in part waters of the United States and that meet the other criteria for coverage (including the requirement that the facility has or will be required to obtain an NPDES permit) are subject to today's rule. In today's rule, the agency is defining the term closed-cycle recirculating system to include, at § 125.92(c)(2), a system with impoundments of waters of the U.S. where the impoundment was lawfully created [6] for the purpose of serving as part of the cooling water system. In determining whether an impoundment qualifies as a closed-cycle recirculating system, the Director will determine whether the make-up water withdrawals for such a system have been minimized. In many cases, EPA expects that such make-up water withdrawals are commensurate with the flows of a closed-cycle cooling tower. Some of these impoundments may qualify for the waste treatment exclusion found in the definition of a waste treatment system at 40 CFR 122.2, and this rule does not affect the applicability of that exclusion.

EPA does not intend for this rule to change the regulatory status of impoundments. Impoundments are addressed in the definition of *waters of the United States* at 40 CFR 122.2 and 40 CFR 230.3. The determination whether an impoundment is a water of the United States is to be made by the Director on a site-specific basis. The EPA and the U.S. Army Corps of Engineers have jointly issued jurisdictional guidance concerning the term *waters of the United States* in light of the Supreme Court's decision in *Solid Waste Agency of Northern Cook County* v. *U.S. Army Corps of Engineers,* 531 U.S. 159 (2001) (SWANCC). A copy of that guidance was published as an Appendix to an Advanced Notice of Proposed Rulemaking on the definition of the phrase *waters of the United States,* see 68 FR 1991, January 15, 2003, which is at *http://www.epa.gov/owow/wetlands/pdf/ANPRM-FR.pdf.* The agencies additionally published guidance in 2008 regarding the term *waters of the United States* in light of both the *SWANCC* and subsequent *Rapanos* case (*Rapanos* v. *United States,* 547 U.S. 715 (2006)). The EPA published a proposed revision to the definition of ''Waters of the United States'' under the Clean Water Act on April 21, 2014 (see 79 FR 22188).

EPA recognizes that some impoundments may be man-made waterbodies that support artificially managed and stocked fish populations. As a result, EPA has included a provision in today's final rule to allow the Director to waive certain permit application requirements for such facilities. Note, however, that these facilities are still subject to the final rule.

EPA acknowledges that the point of compliance for facilities located on

[6] The owner or operator of the facility would provide documentation such as the project purpose statement for the Clean Water Act section 404 permit obtained to construct the impoundment. If the impoundment was created prior to the CWA requirement to obtain a section 404 permit, the owner or operator would provide any other license or permit obtained to lawfully construct the impoundment for the purposes of a cooling water system.

impoundments may also vary depending on where the facility withdraws from a water of the United States. Again, only cooling water systems with withdrawals of cooling water from waters of the United States are covered by section 316(b) and today's rule. Because a facility may withdraw cooling water from a water of the United States either directly or as makeup water for a closed-cycle cooling system, the Director may determine where within a facility's cooling water intake structure is or are the facility's point or points of compliance.

The Agency recognizes that some facilities that have or are required to have an NPDES permit might not own and operate the intake structure that supplies their facility with cooling water. In addressing facilities that have or are required to have an NPDES permit that do not directly control the intake structure that supplies their facility with cooling water, § 125.91 provides (similar to the new facility rule) that facilities that obtain cooling water from a public water system, use reclaimed water from a wastewater treatment facility or desalinization plant, or use treated effluent are not deemed to be using a cooling water intake structure for purposes of this rule. However, obtaining water from another entity that is withdrawing water from a water of the United States will be counted as using a cooling water intake structure for purposes of determining whether an entity meets the threshold requirements of the rule. For example, facilities operated by separate entities might be located on the same, adjacent, or nearby property. One of these facilities might take in cooling water and then transfer it to other facilities that discharge to a water of the United States. Section 125.91(b) specifies that use of a cooling water intake structure includes obtaining cooling water by any sort of contract or arrangement with one or more independent suppliers of cooling water if the supplier or suppliers withdraw water from waters of the United States but that is not itself a new or existing facility subject to CWA section 316(b), except if it is a public water system, a wastewater treatment facility or desalination plant providing reclaimed water, or a facility providing treated effluent for reuse as cooling water pursuant to § 125.91(c).

As a practical matter, the existing facilities subject to this rule are the largest users of cooling water and therefore typically withdraw volumes of water for cooling that warrant owning the cooling water intake structures. In some cases, such as at nuclear power plants or critical baseload facilities, the need for cooling water includes safety and reliability reasons that would likely preclude any independent supplier arrangements. Therefore, EPA expects this provision will have only limited applicability. EPA is nevertheless retaining the provision to prevent facilities from circumventing the requirements of today's rule by creating arrangements to receive cooling water from an entity that is not itself subject to today's rule and that is not otherwise explicitly exempt from today's rule (such as drinking water or treatment plant discharges reused as cooling water).

H. What intake flow thresholds result in an existing facility being subject to the final rule?

EPA determines the cooling water flow at a facility in two ways. The first is based on the DIF, which reflects the maximum intake flow the facility is capable of withdrawing. While this normally is limited by the capacity of the cooling water intake pumps, other parts of the cooling water intake system could impose physical limitations on the maximum intake flow the facility is capable of withdrawing. The second method for determining cooling water flow is based on the AIF, which reflects the actual volume of water withdrawn by the facility. EPA has defined AIF to be the average water withdrawn each year over the preceding three years.[7] Both of these methods are used in today's rule.

Today's final rule applies to facilities that have a total DIF of greater than 2 mgd (see § 125.91).[8] At a threshold of 2 mgd, today's rule covers 99.8 percent of the total water withdrawals by utilities and other industrial sources (if the other criteria for coverage are met), which includes 70 percent of manufacturing facilities and 87 percent of electric generators. EPA also chose the greater than 2 mgd threshold because it was consistent with the applicability criteria in the Phase I rule.[9]

There are substantial environmental benefits that will accrue with a threshold of 2 mgd. For example, EPA's analysis indicates that greater than 82 percent of impinged fish mortality across all facilities would be prevented by this rule at this threshold. EPA also considered a threshold of 50 mgd. The record includes 38 studies documenting IM at more than 40 facilities with flows lower than 50 mgd. Further, the industry questionnaire demonstrates that such facilities are twice as likely to have no controls in place for impingement or entrainment than are facilities with intake flows greater than 50 mgd. In addition, lower intake flow facilities can have similar impacts to those of larger flow facilities as sizable numbers of fish are impinged by lower flow facilities. Moreover, site-specific impacts of lower flow facilities may be significant, particularly where threatened or endangered species are present.

Although smaller flow facilities (those less than 50 mgd) constitute a large proportion of the total number of the facilities regulated (476 of 1,065), the total compliance cost for these smaller facilities are only a small portion of the total compliance cost of the rule ($23 million of $275 million). Thus any perceived aggregate cost savings from setting the threshold higher than 2 mgd would be minimal.

There is no appreciable difference in the cost effectiveness of the rule with a higher applicability threshold. For example, the cost effectiveness of the rule with a threshold of 2 mgd is $0.42 per age-one equivalent losses (A1E). At a threshold of 50 mgd the cost effectiveness would be $0.41 per A1E. In addition, the incremental cost of the 2 mgd threshold relative to a 50 mgd threshold is negligible for the electric power industry at less than 0.1 percent of annual electricity sector revenue, which exceeds $126 billion. The facility-level impacts are negligible to zero at either 2 or 50 mgd threshold. At the 2 mgd threshold, only 5 (1 percent) of the manufacturing facilities have a cost-to revenue ratio exceeding 1 percent (but less than 3 percent). While this drops to zero facilities at the 50 mgd threshold, the difference of 5 facilities out of 509 facilities is not significant. Costs for lower flow facilities are so small that the average annual household utility bill would not measurably decrease by changing the threshold from 2 to 50 mgd. While 58 percent of the small facilities affected by the final rule are below 50 mgd, 40 percent of them already meet one of the compliance alternatives for impingement mortality of the rule and likely would not need to install any additional compliance technologies. And small businesses account for only 17 percent of facilities at or below 50 mgd, demonstrating that there would

[7] For permit terms subsequent to the first permit issued under today's rule, the rule defines AIF as the average flows over the previous 5 years.

[8] The 2004 Phase II rule would have applied to existing power-generating facilities with a design intake flow of 50 mgd or greater. Facilities potentially regulated by the Phase III rule had a DIF of greater than 2 mgd.

[9] For more information, see 65 FR 49067, August 10, 2000.

not be a disproportionate impact on small businesses at a 2 mgd threshold.

Thus, EPA concluded that the threshold of 2 mgd ensures that the users of cooling water causing the most adverse environmental impact are subject to the rule. Raising the threshold for applicability of the rule's impingement and entrainment requirements to 50 mgd as some commenters suggested was not supportable given the statistics and information described above.

Raising the applicability threshold to 50 mgd would have meant that 476 facilities, almost half of the 1,065 facilities subject to the national standards set by today's rule, would not be subject to the rule. Ignoring so many facilities when setting national standards fails to apply the common sense approaches set forth in this rule for minimizing adverse environmental impacts from cooling water intake structures.

Excluding such a large number of facilities from this rule would create regulatory uncertainty for those facilities since they would remain subject to CWA permitting requirements, but without the benefits of the structure of this rule. Directors would have an obligation to establish controls on a case-by-case basis for these lower flow facilities using a BPJ analysis instead of using the more straightforward and transparent provisions of setting controls based on national standards contained in this rule. Such BPJ analyses can be uncertain, and can be time consuming and complex to develop for both Directors and owners and operators of facilities. Case-by-case BPJ permits (instead of permits based on the national standards in today's rule) would likely increase the time and costs to states for such permits to be developed, further delaying the minimization of adverse environmental impacts called for by CWA section 316(b). Maintaining an applicability threshold of 2 mgd DIF best combines the shared goals of minimizing adverse environmental impacts as required by the CWA, and the predictability and flexibility contained in the rule.

EPA acknowledges that there may be circumstances where flexibility in the application of the rule may be called for and the rule so provides. For example, some low flow facilities that withdraw a small proportion of the mean annual flow of a river may warrant special consideration by the Director. As an illustration, if a facility withdraws less than 50 mgd AIF, withdraws less than 5 percent of mean annual flow of the river on which it is located (if on a river or stream), and is not co-located with other facilities with CWISs such that it contributes to a larger share of mean annual flow, the Director may determine that the facility is a candidate for consideration under the de minimis provisions contained at § 125.94(c)(11). In the case of facilities on lakes and reservoirs, co-location would be better determined by multiple CWIS facilities on the same waterbody, rather than distance.

In either case, the flexibilities contained in the rule for the Director to consider the site-specific characteristics of each intake structure within the national standard provide a useful mechanism for facilities with lower intake flows and low impacts to be considered.

EPA is continuing to base applicability on DIF as opposed to AIF for several reasons. In contrast to AIF, DIF is a fixed value based on the design of the facility's operating system and the capacity of the circulating and other water intake pumps. This provides clarity because the DIF does not vary with facility operations, except in limited circumstances, such as when a facility undergoes major modifications. On the other hand, actual flows can vary significantly over sometimes short periods. For example, a peaking power plant might have an AIF close to the DIF during times of full energy production, but an AIF of zero during lengthy periods of standby. Use of DIF provides clarity as to regulatory status, is indicative of the potential magnitude of environmental impact, and avoids the need for monitoring to confirm a facility's status. For more information about these thresholds, see 69 FR 41611, July 9, 2004.

Under this rule, all facilities with a DIF of greater than 2 mgd, that meet the other three criteria for applicability of today's rule, must submit basic information describing the facility, Source Water Physical Data, Source Water Biological Characterization Data, and Cooling Water Intake System Data. In addition, these facilities must submit additional facility-specific information including the selected impingement compliance option, and operational status of each of the facility's units.[10] Certain facilities withdrawing the largest volumes of water for cooling purposes have additional information and study requirements such as relevant biological survival studies and the entrainment study as described below.

The final rule uses AIF rather than DIF for purposes of determining which facilities must provide the information required in § 122.21(r)(9) through (13), referred to as the entrainment study. Thus, the rule provides that any facility subject to the rule with actual flows in excess of 125 mgd must provide an entrainment study with its permit application (which includes the Entrainment Characterization Study at § 122.21(r)(9)).[11] Adverse environmental impacts from entrainment result from actual water withdrawals, and not the maximum designed level of withdrawal. Further, using actual flow might encourage some facilities to adopt operational practices to reduce their flows below 125 mgd AIF to avoid collecting supplemental data and submitting the additional entrainment study. Furthermore, any facility that has DIF greater than 2 mgd, that meets the other three criteria for applicability of today's rule, is required to submit basic information that will allow the Director to verify its determination of whether it meets the 125 mgd AIF threshold.

EPA has selected an administrative threshold of 125 mgd AIF for submission of the entrainment study because this threshold will capture 90 percent of the actual flows but will apply to only 30 percent of existing facilities. Further, based on EPA's data there are no closed-cycle recirculating systems in use above this threshold. The 125 mgd AIF threshold will significantly limit facility burden at more than two-thirds of the potentially affected facilities while focusing the Director on major cooling water withdrawals. Contrary to a number of public comments, however, EPA is not implying or concluding that the 125 mgd threshold is an indicator that facilities withdrawing less than 125 mgd are (1) not causing any adverse impacts or (2) automatically qualify as meeting BTA. In other words, the threshold, while justified on a technical basis, does not result in exemptions from the rule. Instead, EPA is making a policy decision as to which facilities must provide a certain level and type of information. The Director, of course, will retain the discretion to require reasonable information to make informed decisions at the smaller facilities. The 125 mgd threshold focuses on the facilities with the highest intake flows and the highest likelihood of causing adverse impacts; it is not an

[10] The final rule allows the Director to waive certain information submission requirements for facilities that already employ closed-cycle cooling.

[11] For impoundments constructed in uplands or not in waters of the United States, the point of compliance for measuring AIF to determine if it is greater than 125 mgd is the intake into the impoundment from the waters of the United States.

indicator that facilities under that threshold are no longer of concern in the final rule.

In today's rule, EPA seeks to clarify that for some facilities, the DIF is not necessarily the maximum flow associated with the intake pumps. For example, a power plant might have redundant circulating pumps, or might have pumps with a name plate rating that exceeds the maximum water throughput of the associated piping. EPA intends for the DIF to reflect the maximum rate at which a facility can physically withdraw water from a source waterbody (usually normalized to a daily rate in mgd). This also means that a facility that has permanently taken a pump out of service should be able to consider such constraints when reporting its DIF, as the facility's capacity to withdraw water may have fundamentally changed. Additionally, if a facility's flow is limited by constrictions in the piping or other physical limitations (e.g., a given portion of its cooling system that can only safely handle a given amount of flow) and that flow is lower than the DIF for the pumps, the facility should be able to consider such constraints when reporting its DIF, because it is not capable of withdrawing its full pumping DIF without compromising the cooling system.

I. What are the requirements for existing offshore oil and gas facilities, offshore seafood processing facilities or LNG terminals BTA requirements under the final rule?

Under today's rule, existing offshore oil and gas facilities, existing offshore seafood processing facilities and existing LNG terminals will be subject to section 316(b) requirements on a BPJ basis. In the Phase III rule, EPA studied offshore oil and gas facilities and offshore seafood processing facilities [12] and could not identify any technologies (beyond the protective screens already in use) that are technically feasible for reducing impingement or entrainment in such existing facilities.[13] As discussed in the Phase III rule, known technologies that could further reduce impingement or entrainment would result in unacceptable changes in the envelope of existing platforms, drilling rigs, mobile offshore drilling units, offshore seafood processing facilities, and similar facilities as the technologies would project out from the hull, potentially decrease the seaworthiness, and potentially interfere with structural components of the hull. It is also EPA's view that for many of these facilities, the cooling water withdrawals are most substantial when the facilities are operating far out at sea and, therefore, not withdrawing from a water of the United States. EPA is aware that LNG facilities may withdraw hundreds of million gallons per day of seawater for warming (re-gasification). However, some existing LNG facilities might still withdraw water where 25 percent or more of the water is used for cooling purposes on an actual intake flow basis. EPA has not identified a uniformly applicable and available technology for minimizing impingement mortality and entrainment at these facilities. However, technologies might be available for some existing LNG facilities. LNG facilities that withdraw any volume of water for cooling purposes will be subject to site-specific, BPJ determinations of BTA.

EPA has not identified any new data or approaches that would result in a different determination. Therefore, EPA has adopted the approach of the proposed rule and is requiring that NPDES Permit Directors, on a case-by-case basis using BPJ, determine BTA for existing offshore oil and gas extraction facilities, existing offshore seafood processing facilities, and existing LNG terminals.

J. What is a ''new unit'' and how are new units addressed under the final rule?

Today's rule establishes requirements for new units at an existing facility that are different than those applicable to existing units at an existing facility. The requirements for new units at existing facilities are modeled after the requirements for a new facility in the Phase I rule. Under today's rule, a new unit means a newly built, stand-alone unit, whose construction begins after the effective date of the rule. EPA is also clarifying that while Phase I does not include units newly constructed at an existing facility for the same general industrial operation, such units do constitute a new unit at existing facilities and, as such, are subject to today's final rule.

On the basis of the public comments received on how to define ''new unit,'' EPA provides a clear definition for this term in the final rule. The definition for a new unit at an existing facility establishes a clear regulatory framework for both affected facilities and Directors. This definition captures facilities that are undergoing major construction projects involving the construction of a new stand-alone unit, while not discouraging upgrades. For example, a nuclear facility conducting a measurement uncertainty capture or a stretch power uprate, or a fossil-fuel facility repowering an existing generating unit, would not be considered to result in the relevant unit becoming a new unit. As another example, under this definition placing an offshore facility or vessel into a dry dock for maintenance or repair does not result in either the offshore facility, vessel, or the dry dock as being defined as a new unit.

Section VI discusses EPA's rationale for establishing the definitions for new units at existing facilities described below.

1. Electric Generators

The final rule defines a new unit at an existing facility as a newly built, stand-alone unit that is constructed at an existing facility and that does not meet the definition of a new facility. An existing unit that is repowered or undergoes significant modifications (such as where the turbine and condenser are replaced) is not considered a new unit. Exhibit I–4 below provides several examples and whether these hypothetical units will be defined as new or existing units.

EXHIBIT I–4—EXAMPLES OF NEW AND EXISTING UNITS AT EXISTING ELECTRIC GENERATION FACILITIES

Examples of new units at an existing facility	Examples of existing units
A unit that is constructed at a stand-alone location at an existing facility regardless of any plans to retire any other unit at the facility in the future.	A unit that is repowered or undergoes significant modifications.
	A retrofitted with a new boiler or fuel type.

[12] EPA studied naval vessels and cruise ships as part of its developing a general NPDES permit for discharges from oceangoing vessels. (For more information, see *http://cfpub.epa.gov/npdes/home.cfm?program_id=350.*) EPA studied offshore seafood processing facilities and oil and gas exploration facilities in the 316(b) Phase III rule.

[13] As discussed in today's preamble, requirements for new offshore facilities that were set forth in the Phase III rule remain in effect.

2. Manufacturers

At manufacturing facilities that generate electricity onsite, the previous discussion of how to define new units at existing electric generating facilities generally applies. Some manufacturers employ different industrial processes than an electric generator and therefore have different industrial equipment (including cooling systems). In particular, manufacturers may not use a steam condenser or steam turbine for their industrial processes, making the definition for ''repowering'' above inappropriate for manufacturing facilities. However, manufacturers may have opportunities to reuse cooling water that power plants do not, and in site visits, EPA found many manufacturers have conducted energy and water audits resulting in significant reductions in water withdrawals. The final rule provides for manufacturers to receive credit for such reductions in fresh water withdrawals.

It is not as easy to identify a similar conceptual approach for defining new manufacturing units at existing manufacturing facilities because waste heat can be generated from a variety of sources including exothermic processes, product heating and cooling, and the processing, handling, treating, or disposal of feed streams, waste streams, by-products, and recycled components. Sources may include direct cooling transferred across an inert material (e.g., heat exchanger, steam condenser), indirect cooling using a working fluid (e.g., chillers, refrigeration), or contact cooling where cooling water comes into direct contact with a product or process stream.[14] Unlike electric generating units where the majority of cooling water comes from a single process source (the steam condenser), manufacturing units may include many separate non-contact or contact cooling water sources dispersed throughout the production processes and the facility. Thus, a definition for manufacturing units must take into consideration a broader category of cooling water sources.

For power generators, the term ''generating unit'' is quite clear since there is only one product (electricity), the non-contact cooling water predominantly comes from one source, and the application of the term is well understood in the industry. But for some manufacturing facilities, it may be unclear what constitutes a ''unit'' since manufacturing processes can involve numerous vertically integrated processes or production steps that may involve intermediate products. For example, a unit could encompass an entire series of production steps (start to finish) or simply the individual steps. Also, there may be ancillary support equipment that serves various functions and it is not clear whether this will be considered a unit or part of a unit. For example, a petroleum refiner will typically include various processes such as distillation, cracking, hydrotreating, coking, reforming, and different types of various products. Various intermediate products from these processes may be directly transported (piped) from one process to another or stored and some may be sold. And because various intermediate and final process products may be blended into different products, differentiating units on a product or intermediate product basis may not provide clear distinctions.

For these reasons EPA has defined new unit to simply mean a new stand-alone unit. A new unit may include one or more distinct production lines that are added to increase product output and operate parallel to and independently of existing production equipment. A new unit does not include the replacement or rebuilding of one or more distinct production lines or distinct processes involving the replacement of the majority of the waste heat producing equipment that serves as sources of non-contact cooling water and the majority of the heat exchanging equipment that contributes heat to the non-contact cooling water. Such modifications alone do not render the unit a new unit. A unit undergoing such modifications would continue to be considered an existing unit and would be regulated under the existing unit provisions of this rule. This definition therefore does not impose any disincentives for the replacement/upgrade of individual components or ancillary equipment alone.

Exhibit I–5 below provides several examples of whether these hypothetical units are defined as new or existing units. As noted above, the Director has broad discretion to assess the scope of any modifications at the manufacturing facility and to determine whether the new construction comprises a stand-alone unit. For the purposes of today's final rule, the Director does not need to address whether the stand-alone unit is for the same general industrial purposes, or whether the new unit is a replacement unit. The key factors in assessing whether a unit will be defined as new lies with whether the construction results in a stand-alone unit.

EXHIBIT I–5—EXAMPLES OF NEW AND EXISTING UNITS AT MANUFACTURERS

Examples of new units at an existing facility	Examples of existing units at an existing facility
A unit that is constructed at a stand-alone location at an existing facility (either adjacent to existing units or on newly acquired or developed property) regardless of any plans to retire any other unit at the facility in the future.	A unit where only the waste heat generating process equipment or the cooling system equipment is replaced.
A unit that is constructed adjacent to an existing unit for the same industrial activity (such as expanding the production output by building a second unit as a stand-alone unit next to the existing unit).	A unit where modifications are made to the waste heat generating process equipment or the cooling system (e.g., optimization, repairs, upgrades to operational elements).
	Replacement or upgrade of ancillary equipment (e.g., pumps, motors, HVAC, etc.).

K. Amendments Related to the Phase I Rule

EPA is making limited changes to the Phase I rule at 40 CFR Part 125 Subpart I. The changes fall into two categories. The first is deleting the provision in the Phase I rule that would allow a facility to demonstrate compliance with the Phase I BTA requirements in whole or in part through restoration measures. This change responds to the decision of the U.S. Court of Appeals for the Second Circuit, which remanded these provisions to EPA because it concluded that the statute did not authorize

[14] Note that EPA did not include the contact cooling category as part of its analysis of possible closed-cycle recirculating system requirements but contact cooling water does nonetheless fall within the definition of cooling water at § 125.92.

restoration measures to comply with CWA section 316(b) requirements. The second category of changes reflects technical corrections or errors that do not change the substance of the Phase I rule. EPA has not reopened any other aspects of the Phase I rule other than the provisions specifically noted here.

1. Restoration Provisions Not Authorized

The Phase I final rule established two compliance tracks. Track I requires facilities to restrict intake flow and velocity. Track II gives a facility the option of demonstrating to the Director that the control measures it employs will reduce the level of adverse environmental impact to a comparable level to what would be achieved by meeting the Track I requirements. As part of this demonstration, Track II originally allowed a facility to make use of restoration measures. The Comprehensive Demonstration Study allowed a quantitative or qualitative demonstration that restoration measures would meet, in whole or in part, the performance levels of Track I. Similarly, the Verification Monitoring Plan could be tailored to verify that the restoration measures would maintain the fish and shellfish in the waterbody at a substantially similar level to that which would be achieved under Track I. See 66 FR 65280–65281, December 18, 2001.

Upon legal challenge, the Second Circuit Court concluded that EPA exceeded its authority by allowing new facilities to comply with CWA section 316(b) through restoration measures, and remanded that aspect of the rule to EPA. The Supreme Court did not grant the petitions for writs of certiorari concerning restoration provisions. Today's final rule amends Phase I to remove those provisions in §§ 125.84(d) and 125.89(b)(1)(ii) authorizing restoration measures in conformance with the Second's Circuit's decision. Today's rule also specifically deletes permit application requirements contained in the Comprehensive Demonstration Study at § 125.86(c)(2)(ii); evaluation of proposed restoration measures at § 125.86(c)(2)(iv)(C); and verification monitoring requirements at § 125.86(c)(2)(iv)(D)(2) that are specific to restoration. EPA acknowledges these changes might reduce the alternatives available to some Phase I facilities. EPA notes, however, that the deletion of restoration measures does not otherwise alter the availability of Track II. In any event, EPA's determination of BTA for Phase I did not presume reliance on the restoration provisions, and the deletion of restoration measures in no way alters the Agency's BTA determination for Phase I facilities.

2. Corrections to Subpart I

Today's final rule changes the applicability of the technical requirements at § 125.84 and permit application requirements at § 125.86 statement to match the applicability statement at § 125.81(a)(3). The applicability in all three instances should specify DIF or withdrawals ''greater'' than the specified value of 2 mgd. See Basis for the Final Regulation at 66 FR 65270, December 18, 2001.

Today's rule also corrects the source waterbody flow information submission requirements. Track I requirements at § 125.84(b)(3) apply to new facilities that withdraw equal to or greater than 10 mgd. Track I requirements at § 125.84(c)(2) apply to facilities that withdraw less than 10 mgd. The source waterbody flow information under § 125.86(b)(3) requires a facility to demonstrate it has met the flow requirements of both §§ 125.84(b)(3) ''and'' 125.84(c)(2). However, a facility cannot be subject to both §§ 125.84(b)(3) and 125.84(c)(2) at the same time. Accordingly, the word ''and'' should read as ''or'' in § 125.86(b)(3).

In addition, today's final rule corrects the permit application requirement for the Source Water Biological Characterization at § 122.21(r)(4). Accordingly, references to the Source Water Biological Characterization should read as (r)(4). However, the references to the Source Water Biological Characterization at § 125.86(b)(4)(iii), at § 125.87(a), and at § 125.87(a)(2) incorrectly refer to § 122.21(r)(3) and are thus being corrected.

II. Legal Authority for and Background of the Final Regulation

A. Legal Authority

Today's final rule is issued under the authority of Clean Water Act sections 101, 301, 304, 308, 316, 401, 402, 501, and 510, 33 U.S.C. 1251, 1311, 1314, 1318, 1326, 1341, 1342, 1361, and 1370.

B. Purpose of the Regulation

The purpose of today's rule is to reduce impingement and entrainment of fish, shellfish and other aquatic organisms at cooling water intake structures. Today's rule establishes national requirements for cooling water intake structures at existing facilities under section 316(b) of the CWA. That section provides that any standard established pursuant to CWA sections 301 or 306 and applicable to a point source must require that the location, design, construction, and capacity of cooling water intake structures reflect the BTA for minimizing adverse environmental impact. Today's rule establishes requirements applicable to all existing power-generating facilities and existing manufacturing and industrial facilities that are point sources, that have a DIF of greater than 2 mgd from waters of the United States, and use at least 25 percent of the water they withdraw exclusively for cooling purposes on an actual intake flow basis. In addition, EPA is today also making minor changes to its earlier rule establishing section 316(b) requirements for new facilities. Specifically, EPA is removing a provision that would have allowed a restoration-based alternative for complying with performance standards as well as the associated monitoring and other requirements for demonstrating compliance.

C. Background

1. The Clean Water Act

a. General

The Federal Water Pollution Control Act, also known as the CWA, 33 U.S.C. 1251 et seq., seeks to ''restore and maintain the chemical, physical, and biological integrity of the nation's waters.'' 33 U.S.C. 1251(a). Among the goals of the Act is, wherever attainable, an interim goal of water quality which provides for the protection and propagation of fish, shellfish, and wildlife and provides for recreation in and on the water. 33 U.S.C. 1251(a)(2).

In furtherance of these objectives, the CWA establishes a comprehensive regulatory program, key elements of which are (1) a prohibition on the discharge of pollutants from point sources to waters of the United States, except in compliance with the statute and (2) authority for EPA or authorized States or Tribes to issue NPDES permits that authorize and regulate the discharge of pollutants.

CWA section 402 authorizes EPA (or an authorized State or Tribe) to issue an NPDES permit to any person discharging any pollutant or combination of pollutants from a point source into waters of the United States. Forty-six States and one U.S. territory are authorized under section 402(b) to administer the NPDES permitting program. NPDES permits restrict the types and amounts of pollutants, including heat, that may be discharged from various industrial, commercial, and other sources of wastewater. These permits control the discharge of pollutants by requiring dischargers to meet technology-based and possibly water-quality-based effluent limitations.

Under section 316(b), NPDES permits are required to contain conditions to implement the requirements of section 316(b).

CWA section 510 provides that, except as provided in the CWA, nothing will preclude or deny the right of any State (or political subdivision thereof) to adopt or enforce any requirement respecting control or abatement of pollution; except that if a limitation, prohibition or standard of performance is in effect under the CWA, such State may not adopt any other limitation, prohibition, or standard of performance which is less stringent than the limitation, prohibition, or standard of performance under the Act. EPA interprets this to reserve for the States authority to implement requirements that are more stringent than the Federal requirements under state law. *PUD No. 1 of Jefferson County* v. *Washington Dep't of Ecology,* 511 U.S. 700, 705 (1994). New York and California have enacted State requirements that are at least as stringent as those of the final rule, and therefore, EPA has analyzed facilities in those States that are subject to those State requirements as already complying with the final rule.[15] Those facilities still must comply with the administrative requirements of the final rule.

CWA sections 301, 304, and 306 require that EPA develop technology-based effluent limitations guidelines and new source performance standards that are used as the basis for discharge requirements in wastewater discharge permits. EPA develops these effluent limitations guidelines and standards for categories of industrial dischargers on the basis of the pollutants of concern discharged by the industry, the degree of control that can be attained using various levels of pollution control technology appropriate for each industrial process or subcategory, consideration of various economic tests implemented under the authority of the CWA for each level of control, and other factors identified in CWA sections 304 and 306 (such as non-water quality environmental impacts including energy impacts). EPA has promulgated regulations setting effluent limitations guidelines and standards under CWA sections 301, 304, and 306 for 57 industry categories. See 40 CFR parts 405 through 471. EPA has established effluent limitations guidelines and standards that apply to the industry categories that are the largest users of cooling water (e.g., steam electric power generation, paper and allied products, petroleum refining, iron and steel manufacturing, and chemicals and allied products), as well as many other industrial categories that may include facilities subject to this final rule.

b. Section 316(b)

Section 316(b) states, in full,

> Any standard established pursuant to section 301 or section 306 of [the Clean Water] Act and applicable to a point source shall require that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact.

33 U.S.C. 1326(b). This provision is unique among CWA provisions because it addresses the adverse environmental impact caused specifically by the intake of cooling water, in contrast to other provisions of the Act that regulate the discharge of pollutants into waters of the United States.

The CWA does not further define the substantive standard specified in section 316(b)—''best technology available for minimizing adverse environmental impact'' (BTA). 33 U.S.C. 1326(b). The standard that cooling water intake structures must achieve under section 316(b)—BTA—is a different standard from those prescribed under sections 301 and 306 of the Act. *Riverkeeper, Inc.* v. *EPA,* 358 F.3d 174 (2d Cir. 2004). Moreover, unlike sections 304 and 306, section 316(b) does not set forth the specific factors that the EPA must consider in determining BTA. BTA is ''the only substantive statutory requirement explicitly applicable to the intake structure regulations.'' *Id.* at 186. Unlike other provisions of the Act, section 316(b) standards are not subject to a ''host'' of other requirements or limitations. *Ibid.* There is no ''elucidating language applicable to the BTA test.'' *Entergy Corp.* v. *Riverkeeper, Inc.,* 556 U.S. 208, 221 (2009).[16]

Section 316(b) does, however, cross-reference sections 301 and 306 of the CWA by stating that any standards established pursuant to those sections also require that cooling water intake structures reflect BTA. *Ibid.* This cross reference, in the view of the Second Circuit, is an invitation, not a straitjacket. EPA ''may'' look to the referenced sections in discerning what factors Congress intended EPA to consider in determining BTA.

> Because section 316(b) refers to sections 301 and 306 but provides a different standard (''best technology available for minimizing adverse environmental impact'' instead of, for example, ''best available demonstrated control technology'') and does not explicitly provide that regulations pursuant to section 316(b) are subject to the requirements of sections 301 and 306, we think it is permissible for the EPA to look to those sections for guidance but to decide that not every statutory directive contained therein is applicable to the Rule.

The terse statutory description of BTA and the absence of any prescribed statutory factors for consideration in determining BTA suggest that Congress delegated EPA significant rulemaking discretion in this area.[17]

As noted, in contrast to effluent limitations guidelines and standards, the CWA does not describe the factors to be considered in establishing section 316(b) substantive performance requirements that reflect the ''best technology available for minimizing adverse environmental impact'' nor does it require that EPA develop uniform nationally applicable performance requirements through rule making.

The U.S. Supreme Court has, however, recently provided guidance, in *Entergy Corp.* v. *Riverkeeper, Inc.,* in interpreting section 316(b) and what factors EPA may consider in its standard-setting. That decision addressed the question of whether CWA section 316(b) authorizes EPA to compare costs and benefits of various technologies when setting national performance standards for cooling water intake structures under CWA section 316(b). In overturning EPA's earlier rule to establish section 316(b) requirements for existing facilities, the Second Circuit held that balancing costs and benefits was an impermissible factor for standard setting under section 316(b). The Supreme Court reversed and remanded the Second Circuit ruling in a 6–3 opinion authored by Justice Scalia. The Court held that it is permissible for EPA to consider a cost-benefit analysis in setting national performance standards for cooling water intake structures under section 316(b).

[15] For example, California policy addressing 19 coastal power plants would not affect the compliance costs of inland facilities.

[16] Included in an appendix to the decision is a table comparing CWA statutory standards under 301, 306 and 316(b), the table. In the column headed ''Statutorily Mandated Factors,'' for section 316(b), the table states ''N/A.''

[17] The Second Circuit has noted the limited legislative history for section 316(b). ''This paucity of legislative history, when measured against the volumes of drafts and speeches devoted to other aspects of the 1972 amendments, and when combined with the brevity of the provision itself, counsels against imputing much specific intent to Congress beyond the section's words themselves. To the extent the provision is silent on issues to which other sections speak, we hesitate to draw the negative inference that the brevity of *section 316(b)* reflects an intention to limit the EPA's authority rather than a desire to delegate significant rulemaking authority to the Agency.'' *Id.* at 187.

The Court held that EPA has the discretion to consider costs and benefits under section 316(b) but is not required to do so. 556 U.S. 208, 222–23.

The Court's discussion of the language of section 316(b)—section 316(b) is ''unencumbered by specified statutory factors''—and its critique of the Second Circuit's decision affirms EPA's broad discretion to consider a number of factors in standard setting under section 316(b). While the Supreme Court's decision is limited to whether or not EPA may properly consider one factor (cost/benefit analysis) under section 316(b), the language also indicates that EPA has wide discretion in considering other factors that it deems relevant to 316(b) standard setting. 556 U.S. 208, 222 (2009). (''It is eminently reasonable to conclude that § *1326b's* silence is meant to convey nothing more than a refusal to tie the agency's hands as to whether cost-benefit analysis should be used, and if so to what degree.'').

Regarding the other factors EPA may, but is not mandated to, consider, as noted above, section 316(b) cross references CWA sections 301 and 306 by requiring that any standards established pursuant to those sections also must require that the location, design, construction and capacity of intake structures reflect BTA. Following the decisions of the Second Circuit in reviewing both the Phase I and Phase II rules, EPA has interpreted the cross reference as authorizing consideration of the factors considered under those provisions to help guide section 316(b) rulemaking without determining that each of those factors is applicable to this rule. Thus, for example, section 306 directs EPA to establish performance standards for new sources based on the BADT (best available demonstrated control technology). 33 U.S.C. 1316(a)(1). In establishing BADT, EPA ''shall take into consideration the cost of achieving such effluent reduction, and any non-water quality environmental impact and energy requirements.'' 33 U.S.C. 1316(b)(2)(B).

Similarly, CWA section 301 requires EPA, in establishing standards known as *effluent limitations guidelines,* to consider specified factors. For a complete discussion of factors considered in establishing section 301 effluent limits, see 76 FR 22178–22179, April 20, 2011. But, EPA in establishing section 316(b) standards is not constrained in what factors it considers or bound by any statutorily prescribed tests as is the case with sections 301 and 306. Consequently, while section 316(b) expressly refers to section 301 and 306, and, while it shares some of the same words used in sections 301(b) and 306, its language is different.[18] These differences in the statutory descriptions, coupled with the brevity of section 316(b) itself, prompt EPA to examine the factors described in section 301, 306 and, ultimately, section 304 where relevant in EPA's determination of the ''best technology available to minimize adverse environmental impact'' of cooling water for intake structures for existing facilities.

As noted above, there are significant differences between section 316(b) and sections 301, 304 and 306. See *Riverkeeper, Inc.* v. *United States Environmental Protection Agency* (2nd Cir. Feb. 3, 2004) (''not every statutory directive contained [in sections 301 and 306] is applicable'' to a section 316(b) rulemaking). Moreover, as the Supreme Court recognized, while the provisions governing the discharge of toxic pollutants must require the elimination of discharges if technically and economically achievable, section 316(b) has the less ambitious goal of ''minimizing adverse environmental impact.'' 556 U.S. at 219. In contrast to the effluent limitations provisions, the object of the best technology available is explicitly articulated by reference to the receiving water: To minimize adverse environmental impact in the waters from which cooling water is withdrawn. This difference is reflected in EPA's past practices in implementing sections 301, 304, as contrasted with 316(b). For example, EPA has established BAT effluent limitations guidelines and new source performance standards on the basis of the efficacy of one or more technologies to reduce pollutants in wastewater in relation to their costs without necessarily considering the impact on the receiving waters. This contrasts to 316(b) requirements which historically have been developed on a site-specific basis, where EPA has considered the costs of technologies in relation to the benefits of minimizing adverse environmental impact in establishing 316(b) requirements. In *Re Public Service Co. of New Hampshire,* 10 ERC 1257 (June 17, 1977); *In Re Public Service Co. of New Hampshire,* 1 EBAD 455 (Aug. 4, 1978); *Seacoast Anti-Pollution League* v. *Costle,* 597 F. 2d 306 (1st Cir. 1979). EPA concluded that, because both section 301 and 306 are expressly cross-referenced in section 316(b), EPA could reasonably interpret section 316(b) as authorizing consideration, where appropriate, of the same factors, including costs. EPA stresses that it may therefore consider some of the same factors, even if it is not legally required to consider them in the same way.

2. Early Litigation History

On January 19, 1993, a group of individuals and environmental organizations[19] filed, under CWA section 505(a)(2), 33 U.S.C. 1365(a)(2), a complaint in *Cronin, et. al.* v. *Reilly,* 93 Civ. 314 (LTS) (S.D.N.Y.). The plaintiffs alleged that EPA had failed to perform a nondiscretionary duty to issue regulations implementing CWA section 316(b), 33 U.S.C. 1326(b). In 1995, EPA and the plaintiffs executed a consent decree in the case. As amended, it provided for EPA to implement CWA section 316(b) by prescribed dates in the three separate rule-making proceedings. Phase I concerned cooling water intake structures at new facilities, Phase II existing power plants using large volumes of cooling water and Phase III for existing smaller-flow power plants and factories in at least four industrial sectors (pulp and paper making, petroleum and coal products manufacturing, chemical and allied manufacturing, and primary metal manufacturing). EPA promulgated the Phase I rule in December, 2001, the Phase II rule in July, 2004 and the Phase III rule in June, 2006.

On November 17, 2006, some of the same environmental organizations in the *Cronin* case filed a second complaint, amended on January 19, 2007, in *Riverkeeper, et al.* v. *EPA,* 06 Civ. 12987 (S.D.N.Y.) asserting that EPA's Phase III rule failed to discharge EPA's duty under CWA section 316(b).

On August 14, 2008, EPA filed a motion to terminate the *Cronin* proceeding because it had discharged its

[18] Compare ''best technology available for minimizing adverse environmental impacts'' with ''*best practicable control technology currently available'' (301(b)(1)A)), ''best conventional pollutant control technology (301(b)(2)(E)), ''best available technology economically achievable'' (301(b)(2)(A)), and best available demonstrated control technology, (306(b)(1)(B)).* Section 316(b), section 301(b)(1)(A)—the BPT provision—section *301(b)(2)(E)—the BCT provision*—section 301(b)(1)(B)—the BAT provision—and section 306(b)(2)(E). All include the terms ''*best,*'' ''*technology,*'' and ''*available,*'' but none also include the modifying phrase ''for minimizing adverse environmental impacts,'' found in section 316(b). See 33 U.S.C. 1311(b)(1)(A) and (2)(A).

[19] The plaintiffs are the following: Riverkeeper, Inc.; Alex Matthiessen, a/k/a The Hudson Riverkeeper; Maya K. Van Rossum, a/k/a The Delaware Riverkeeper; Terrance E. Backer, a/k/a The Soundkeeper; John Torgan, a/k/a The Narragansett BayKeeper; Joseph E. Payne, a/k/a The Casco BayKeeper; Leo O'Brien, a/k/a the San Francisco BayKeeper; Sue Joerger, a/k/a The Puget Soundkeeper; Steven E. Fleischli, a/k/a The Santa Monica BayKeeper; Andrew Willner, a/k/a The New York/New Jersey Baykeeper; The Long Island Soundkeeper Fund, Inc.; The New York Coastal Fishermen's Association, Inc.; and The American Littoral Society, Inc.

obligations (to take final action) under the decree with respect to the 2004 Phase II and 2006 Phase III rulemakings. Subsequently, EPA entered into a settlement with the plaintiffs in both lawsuits. Under the settlement agreement, EPA agreed to sign a notice of a proposed rulemaking implementing CWA section 316(b) at existing facilities no later than March 14, 2011, and to sign a notice taking final action on the proposed rule no later than July 27, 2012. Plaintiffs agreed to seek dismissal of both their suits, subject to a request to reopen the *Cronin* proceeding if EPA failed to meet the agreed deadlines. The district courts have now entered orders of dismissal. On March 11, 2011, the parties agreed to an amendment to the settlement agreement to extend the date for proposal to March 28, 2011. On July 17, 2012, the parties agreed to an amendment to the settlement agreement to extend the date for the final rule to June 27, 2013. On June 21, 2013, the parties agreed to extend the date to November 4, 2013, to accommodate completion of formal consultation under the Endangered Species Act. In part due to the government shutdown, on November 12, 2013, the parties agreed to extend the date to January 14, 2014. On February 10, 2014, to continue progress on the Endangered Species Act (ESA) consultation process, the parties agreed to extend the date to April 17, 2014. Finally, on April 23 2014, in a conference with the court EPA informed the judge that the EPA and the Services would complete the ESA consultation, so that the EPA would sign the rule by May 16, 2014. The court entered an order provisionally reinstating the case if EPA failed to inform the court by May 19, 2014 that it had taken the contemplated action. On May 19, 2014, the Administrator signed this notice for publication in the **Federal Register**.

3. Prior EPA Actions To Address Cooling Water Intake Structures

a. 1976 Rulemaking

In April 1976, EPA promulgated regulations under section 316(b) that addressed cooling water intake structures. 41 FR 17387, April 26, 1976. The rule added a new § 401.14 to 40 CFR Chapter I that reiterated the requirements of CWA section 316(b). It also added a new part 402, which included three sections: (1) § 402.10 (Applicability), (2) § 402.11 (Specialized definitions), and (3) § 402.12 (Best technology available for cooling water intake structures). Section 402.10 stated that the provisions of part 402 applied to ''cooling water intake structures for point sources for which effluent limitations are established pursuant to section 301 or standards of performance are established pursuant to section 306 of the Act.'' Section 402.11 defined the terms *cooling water intake structure, location, design, construction, capacity,* and *Development Document.* Section 402.12 included the following language:

> ''The information contained in the Development Document shall be considered in determining whether the location, design, construction, and capacity of a cooling water intake structure of a point source subject to standards established under section 301 or 306 reflect the best technology available for minimizing adverse environmental impact.''

In 1977, electric utility companies challenged those regulations, arguing that EPA had failed to comply with the requirements of the Administrative Procedure Act in promulgating the rule. Specifically, the utilities argued that EPA had violated the Administrative Procedure Act in promulgating regulations mandating consideration of the information in the Development Document in establishing 316(b) conditions in individual NPDES permits because EPA had neither published the Development Document in the **Federal Register** nor properly incorporated the document into the rule by reference. The U.S. Court of Appeals for the Fourth Circuit agreed. The court determined that the information in the Development Document was part of the substance of a regulation imposing specific obligations in mandatory terms. As such, the information must either be published in the **Federal Register** in its entirety or to be reasonably available and properly incorporated by reference under **Federal Register** requirements. The court explained it did not object to site-specific implementation of the section 316(b) requirements (''[w]hile we emphasize we do not fault EPA for its point source by point source application''), it did require EPA to ''devise a less uncertain method of advising those affected of the conditions by which they are to be bound.'' *Appalachian Power Co.* v. *Train,* 566 F.2d 451, 457 (4th Cir. 1977). Without reaching the merits of the regulations themselves, the court remanded the rule. EPA later withdrew part 402. (See 44 FR 32956, June 7, 1979.) Section 402.10, however, now codified at § 401.14, remains in effect.

Following the Fourth Circuit remand of EPA's section 316(b) regulations in 1977, NPDES permit authorities have made decisions implementing CWA section 316(b) and § 401.14 without the direction of a national rule. EPA published draft guidance addressing section 316(b) implementation in 1977. See *Draft Guidance for Evaluating the Adverse Impact of Cooling Water Intake Structures on the Aquatic Environment: Section 316(b) Public Law 92–500* (U.S. EPA 1977). That draft guidance describes the studies recommended for evaluating the impact of cooling water intake structures on the aquatic environment and recommends a basis for determining the BTA for minimizing adverse environmental impact. The 1977 section 316(b) draft guidance states, ''[t]he environmental-intake interactions in question are highly site-specific and the decision as to best technology available for intake design, location, construction, and capacity must be made on a case-by-case basis'' (Section 316(b) Draft Guidance, U.S. EPA 1977, p. 4). This site-specific approach was also consistent with the approach described in the 1976 Development Document referenced in the remanded regulation. (See DCN 1–1056–TC from the Phase I docket.) The 1977 section 316(b) draft guidance suggested a general process for developing information needed to support section 316(b) decisions and presenting that information to the Director. The process involved developing a site-specific study of the environmental effects associated with each facility that uses one or more cooling water intake structures, and consideration of that study by the Director in determining whether the facility must make any changes for minimizing adverse environmental impact. Under this framework, the Director determined whether appropriate studies have been performed, whether a given facility has minimized adverse environmental impact, and what, if any, technologies may be required.

b. Phase I—New Facility Rule

i. Rulemaking

On November 9, 2001, EPA took final action on regulations governing cooling water intake structures at new facilities. See 66 FR 65255, December 18, 2001. On December 26, 2002, EPA made minor changes to the Phase I regulations. 67 FR 78947. The final Phase I new facility rule (40 CFR part 125, Subpart I) establishes requirements applicable to the location, design, construction, and capacity of cooling water intake structures at new facilities that have a design capacity to withdraw greater than 2 mgd and use at least 25 percent of the water they withdraw solely for cooling purposes on an actual intake flow basis.

In the new facility rule, EPA adopted a two-track approach. Under Track I, facilities that withdraw equal to or greater than 10 mgd were required to meet three requirements. First, the intake flow of the cooling water intake structure is restricted, at a minimum, to a level commensurate with that which could be attained by use of a closed-cycle, recirculating cooling system. Second, the design through-screen intake velocity is restricted to 0.5 fps (foot per second). Third, the total quantity of intake is restricted to a proportion of the mean annual flow of a freshwater river or stream, or to a level necessary to maintain the natural thermal stratification or turnover patterns (where present) of a lake or reservoir except in cases where the disruption is beneficial, or to a percentage of the tidal excursions of a tidal river or estuary. Further, if there are, for example, endangered or threatened species stressed by a facility's intake structure, a facility that would otherwise meet the applicable performance requirements may have to select and implement additional design and construction or operational measures to address impingement mortality and entrainment if these measures are inadequate to protect the species. Facilities with greater than 2 mgd but less than 10 mgd flows are not required to reduce intake flow to a level commensurate with a closed-cycle, recirculating cooling system, but they must still meet specific operational criteria.

Under Track II, a facility had the opportunity to demonstrate to the NPDES permitting authority (Director) that the technologies it employs will reduce the level of adverse environmental impact to a comparable level to what would be achieved by meeting the Track I requirements for restricting intake flow and velocity. In making this demonstration, the regulations allow a facility to rely on a combination of measures in addition to technology controls for reducing impingement and entrainment to achieve results equivalent to the Track I intake flow and velocity requirements. Among these measures, the rule would have allowed restoration of the affected waterbody through efforts such as restocking fish and improving the surrounding habitat to offset the adverse effects that would otherwise be caused by operating the intake structures. The Second Circuit, in reviewing the new facility rule, determined that section 316(b) did not authorize the use of restoration measures in complying with the EPA performance standard. (Note that EPA is removing the provision related to restoration measures from the CFR in this rulemaking but has included the above description of the Phase I rule for completeness.) For more information, see Section I above.

In addition, under the Phase I rule, the Director may establish less stringent alternative requirements for a facility if compliance with the Phase I standards would result in compliance costs wholly out of proportion to those EPA considered in establishing the Phase I requirements or would result in significant adverse impacts on local air quality, water resources, or local energy markets.

EPA specifically excluded new offshore oil and gas extraction facilities from the Phase I new facility rule but committed to consider establishing requirements for such facilities in the Phase III rulemaking. 66 FR 65338, December 18, 2001.

ii. Subsequent Litigation

Various environmental and industry groups challenged the Phase I rule. In February 2004, the Second Circuit sustained the entire rule except for the restoration provision, ruling that restoration was not a technology as provided for in section 316(b). With respect to the other provisions of the rule, the court concluded the Phase I rule was based on a reasonable interpretation of the applicable statute and sufficiently supported by the record. Restoration provisions of the rule were remanded to EPA for further rulemaking consistent with the court's decision. *Riverkeeper, Inc.* v. *EPA,* 358 F.3d 174, 191 (2nd Cir., 2004). Today's rule removes the restoration provisions from the Phase I rule. For more details, see Chapter I of this preamble.

c. Phase II—Large Flow Existing Power Plants

i. Rulemaking

On February 16, 2004, EPA took final action on regulations governing cooling water intake structures at certain existing power-producing facilities. 69 FR 41576, July 9, 2004. The final 2004 Phase II rule applied to existing facilities that are point sources; that, as their primary activity, both generate and transmit electric power or generate electric power for sale or transmission; that use or propose to use a cooling water intake structure with a total DIF of 50 mgd or more to withdraw water from waters of the United States; and that use at least 25 percent of the withdrawn water exclusively for cooling purposes on an actual intake flow basis. In addition, power producers fitting the description above were also subject to the final 2004 Phase II rule even if they obtain their cooling water from one or more independent suppliers of cooling water. Such facilities were subject to the rule if their supplier withdraws water from waters of the United States even if the supplier was not itself a 2004 Phase II existing facility. EPA included this provision to prevent circumvention of the 2004 Phase II rule requirements by a facility purchasing cooling water from entities not otherwise subject to section 316(b).

The final 2004 Phase II rule and preamble also clarified the definition of an *existing* power-producing facility. The 2004 Phase II rule defined an *existing facility* as "any facility that commenced construction as described in § 122.29(b)(4) on or before January 17, 2002; and any modification of, or addition of a unit at such a facility that does not meet the definition of a new facility at § 125.83." Because the definition of the term *existing facility* was based in part on the Phase I definition of the term *new facility,* the preamble to the final 2004 Phase II rule also clarified and provided some examples of how the definition of *existing facility* might apply to certain changes at power-producing facilities.

Under the 2004 Phase II rule, EPA established BTA performance standards for the reduction of impingement mortality and, under certain circumstances, entrainment (see 69 FR 41590–41593, July 9, 2004). The performance standards consisted of ranges of reductions in impingement mortality and, if applicable, entrainment (e.g., reduce impingement mortality by 80 to 95 percent and/or entrainment by 60 to 90 percent) relative to a *calculation baseline* that reflected the level of impingement mortality and entrainment that would occur absent specific controls. These performance standards were not based on a single technology but, rather, on consideration of a suite of technologies that EPA determined were commercially available and economically achievable for the industries affected as a whole (69 FR 41598–41610, July 9, 2004). EPA based the impingement mortality and entrainment performance standards on a suite of technologies because it found no single technology to be effective at all affected facilities. For impingement standards, these technologies included the following: (1) Fine- and wide-mesh wedgewire screens, (2) barrier nets, (3) modified screens and fish return systems, (4) fish diversion systems, and (5) fine-mesh traveling screens and fish return systems. With regard to entrainment reduction, these technologies include the following: (1) Aquatic filter barrier systems, (2) fine-mesh wedgewire screens, and (3) fine-mesh traveling screens with fish return systems. Because EPA based the performance standards on a combination of technologies and because of the uncertainty inherent in predicting the efficacy of one or more of these technologies as applied to different facilities, EPA promulgated these standards as ranges. Furthermore, because the site-specific performance was based on a comparison to a once-through system without any specific controls on the shoreline near the source waterbody (i.e., calculation baseline, for more details see Section III.B.1 of the preamble to the proposed rule, 76 FR 22185, April 20, 2011), the rule also allowed facilities to receive credit toward meeting the performance standards for impingement and entrainment reduction associated with alternative locations of their intakes (e.g., deep water where fish and shellfish were less abundant).

The types of performance standard applicable to a facility (i.e., reductions in impingement mortality only or both impingement mortality and entrainment) were based on several factors, including the facility's location (i.e., source waterbody), rate of use (capacity utilization rate), and the proportion of the waterbody withdrawn.

The 2004 Phase II rule identified five compliance alternatives to meet the performance standards. A facility could demonstrate to the Director one of the following: (1) That it has already reduced its flow commensurate with a closed-cycle recirculating system (to meet both impingement mortality and entrainment), or that it has already reduced its maximum through-screen velocity to 0.5 fps or less (to meet the impingement performance standard only); (2) that its cooling water intake structure configuration meets the applicable performance standards; (3) that it has selected design and construction technologies, operational measures, and/or restoration measures that, in combination with any existing design and construction technologies, operational measures, and/or restoration measures, meet the applicable performance standards; (4) that it meets the applicability criteria and has installed and is properly operating and maintaining a rule-specified and/or approved State-specified design and construction technology (i.e., submerged cylindrical wedgewire screens) in accordance with § 125.99(a) or an alternative technology that meets the appropriate performance standards and is approved by the Director in accordance with § 125.99(b); or (5) that its costs of compliance would be significantly greater than either the costs considered by the Administrator for a like facility to meet the applicable performance standards, or the benefits of meeting the applicable performance standards at the facility. Under the cost-cost comparison alternative, a Director could determine that the cost of compliance for a facility would be significantly greater than the costs considered by EPA in establishing the applicable impingement mortality and entrainment performance standards. Similarly, under the cost-benefit comparison alternative, a Director could determine that the cost of compliance for a facility would be significantly greater than the benefits of complying with the applicable performance standards. If either of these determinations were made, the Director would have to make a site-specific determination of BTA for minimizing adverse environmental impact that came as close as practicable to meeting the applicable performance standards at a cost that did not significantly exceed either the costs EPA considered in establishing these standards or the site-specific benefits of meeting these standards.

The final 2004 Phase II rule also provided that a facility that chooses specified compliance alternatives might request that compliance with the requirements of the rule be determined on the basis of implementing a Technology Installation and Operation Plan (TIOP) that would indicate how the facility would install and ensure the efficacy, to the extent practicable, of design and construction technologies, and/or operational measures, and/or a Restoration Plan. The rule also established requirements for developing and submitting a TIOP (§ 125.95(b)(4)(ii)) and provisions that specified how compliance could be determined on the basis of implementing a TIOP (§ 125.94(d)). Under these provisions, a TIOP could be requested in the first permit term, and continued use of a TIOP could be requested where a facility was in compliance with such plan and/or its Restoration Plan.

ii. Subsequent Litigation

Industry, environmental stakeholders, and some States [20] challenged many aspects of the 2004 Phase II regulations. On January 25, 2007, the Second Circuit (*Riverkeeper, Inc.* v. *EPA,* 475 F.3d 83, (2d Cir., 2007)) upheld several provisions of the 2004 Phase II rule and remanded others to EPA for further rulemaking.

As noted above, for the 2004 Phase II rule EPA did not select closed-cycle cooling as BTA. Instead, EPA selected a suite of technologies to reflect BTA, including, for example, screens, aquatic filter barriers, and barrier nets. According to the chosen technologies, EPA established national performance standards for reducing impingement mortality and entrainment of fish and fish organisms but did not require the use of any specific technology. Among the aspects of the rule the Second Circuit remanded for further clarification was EPA's decision to reject closed-cycle cooling as BTA and EPA's determination of performance ranges as BTA. In addition, the Second Circuit found that, consistent with its Phase I decision, restoration was not authorized under the CWA as a technology for BTA and that EPA's cost-benefit site-specific compliance alternative was not in accord with the CWA. There are also several issues for which the court requested additional clarification and some instances where the court determined that EPA had failed to provide adequate notice and opportunity to comment on certain provisions of the rule.

iii. Suspension

As a result of the decision in *Riverkeeper, Inc.* v. *EPA,* 475 F.3d 83, (2d Cir., 2007), EPA, on July 9, 2007 (72 FR 37107) suspended the requirements for cooling water intake structures at 2004 Phase II existing facilities, pending further rulemaking. Specifically, EPA suspended the provisions in § 122.21(r)(1)(ii) and (r)(5), and part 125 Subpart J, with the exception of § 125.90(b). EPA explained that suspending the 2004 Phase II requirements was an appropriate response to the Second Circuit's decision and that such action would allow it to consider how to respond to the remand. In addition, suspending the 2004 Phase II rule was responsive to the concerns of the regulated community and permitting agencies, both of whom sought guidance regarding how to proceed in light of the approaching deadline for compliance with the remanded rule. EPA's suspension clarified that pending further rulemaking, permit requirements for cooling water intake structures at 2004 Phase II facilities should be established on a case-by-case, BPJ basis (see § 125.90(b)).

iv. Supreme Court Decision

Following the decision in the Second Circuit, several industry group litigants

[20] Rhode Island, Connecticut, Delaware, Massachusetts, New Jersey, and New York.

petitioned the U.S. Supreme Court to hear an appeal regarding several issues in the case. *Entergy Corp.* v. *Riverkeeper, Inc. et al., S. Ct. No. 07–588, et al.* On April 14, 2008, the Supreme Court granted the petitions for writs of certiorari submitted by these 2004 Phase II litigants, but it limited its review to the issue of whether section 316(b) authorizes EPA to compare costs with benefits in determining BTA for cooling water intake structures. The Supreme Court held oral arguments in this case on December 2, 2008, and issued a decision on April 1, 2009. As explained above, the Supreme Court held that it is permissible for EPA to rely on cost-benefit analysis in decision making. The court indicated that the phrase ''best technology available for minimizing adverse environmental impact'' does not unambiguously preclude use of cost-benefit analysis in decision making. 566 U.S. at 223(2009). The ruling supports EPA's discretion to consider costs and benefits, but it imposes no obligation on the Agency to do so.

d. Phase III—Existing Power Plants Below 50 mgd, Existing Manufacturing Facilities, and New Offshore Oil and Gas Facilities

i. Rulemaking

On June 16, 2006, EPA published a final Phase III rule that established categorical regulations for new offshore oil and gas extraction facilities that have a DIF threshold of greater than 2 mgd and that withdraw at least 25 percent of the water exclusively for cooling purposes on an actual intake flow basis. The rule establishes requirements that address intake velocity, proportionate flow for sensitive locations, design and construction technologies or operational measures, monitoring and recordkeeping, based on if a facility employs a sea chest or not, and is fixed or not. Like the Phase I rule, this rule includes a Track II. In the Phase III rule, EPA declined to establish national standards for Phase III existing facilities. Instead it concluded that CWA section 316(b) requirements for electric generators with a DIF of less than 50 mgd and all existing manufacturing facilities would continue to be established on a case-by-case basis under the NPDES permit program using BPJ. (71 FR 35006, June 16, 2006).

ii. Subsequent Litigation

Following promulgation of the rule, a number of parties filed petitions for review that were subsequently consolidated for hearing in the U.S. Court of Appeals for the Fifth Circuit. In 2009, EPA petitioned the Fifth Circuit to remand to the Agency those parts of the rule that applied to existing facilities. Specifically, EPA requested remand of those provisions in the Phase III rule that establish 316(b) requirements at electric generators with a DIF of less than 50 mgd, and the provision establishing requirements for existing manufacturing facilities on a case-by-case basis using BPJ. This request did not affect the Phase III rule requirements that establish categorical regulations for new offshore oil and gas extraction facilities that have a DIF threshold of greater than 2 mgd and that withdraw at least 25 percent of the water exclusively for cooling purposes on an actual intake flow basis.

On July 23, 2010, the U.S. Court of Appeals for the Fifth Circuit issued a decision affirming the parts of Phase III rule relating to new offshore oil and gas facilities. The court granted EPA's motion to remand the rule with respect to existing facilities. In sustaining the requirements for new offshore oil and gas facilities, the Fifth Circuit upheld EPA's decision not to use cost benefit balancing in determining the requirements for these new facilities.

III. Environmental Effects Associated With Cooling Water Intake Structures

A. Introduction

Multiple types of adverse environmental effects may be associated with CWIS operations at regulated facilities. Many facilities employ once-through cooling water systems that impinge fishes and other aquatic organisms on intake screens. Impinged organisms may be killed, injured, or weakened. In addition, early life stage fish or planktonic organisms can be entrained by the CWIS and subjected to high velocity and pressure, increased temperature, and chemical anti-biofouling agents in the system. These factors are highly lethal in most cases, as early life stages of larvae are highly sensitive and very unlikely to survive entrainment. Even if an organism is entrained as an egg and survives, its chances of surviving beyond the larvae stage are dramatically lower than eggs that were never entrained. Thus, unless measures to protect larvae are in place, egg survival does not indicate that adverse environmental impacts have been avoided. Consistent with its treatment of entrainment in past 316(b) rules, EPA assumes for the purposes of a national rule that 100 percent of entrained organisms suffer mortality.

The effects of CWIS on aquatic habitats and biota in the waterbody do not occur in isolation from other ongoing physical, chemical, and biological stressors. Anthropogenic stressors may include: Degraded water and sediment quality, low dissolved oxygen (DO) levels, eutrophication, fishing, channel or shoreline (habitat) modification (intake structure and other flood or storm controls), hydrologic regime changes and invasive species. For example, many aquatic organisms subject to IM&E (impingement mortality and entrainment) reside in impaired (i.e., CWA 303(d) listed) waterbodies. The effects of anthropogenic stressors on biota may contribute to or compound the impact of IM&E, depending on the influence of location-specific factors. In addition to stressors acting on biota near a single CWIS, multiple CWISs and facilities located in close proximity on the same waterbody may have additive or cumulative effects on aquatic communities. And, although it is difficult to measure, the compensatory ability of an aquatic population, which is the capacity for a species to increase survival, growth, or reproduction rates in response to decreased population, is likely compromised by IM&E and the cumulative impact of other stressors in the environment over extended periods of time.

B. Major Anthropogenic Stressors in Aquatic Ecosystems

All ecosystems and their biota are subject to natural variability in environmental conditions (e.g., seasonal cycles, foliage presence) as well as periodic large-scale disturbances (e.g., drought, flood, fire). In contrast, anthropogenic stressors tend to be more chronic in nature and can often lead to long-term environmental degradation associated with decreased biodiversity, reduced primary and secondary production, and a lowered ecosystem resiliency (i.e., ability of the ecosystem to recover to its original state from perturbations).[21] Several of the more important anthropogenic stressors are discussed below, with CWIS-related impacts considered as a separate category of stress.

1. Habitat Loss

Structural aquatic habitat is generally recognized as the most significant determinant of the nature and composition of aquatic communities. Most 316(b) facilities have been built on shoreline locations where industrial buildings, roadways, canals, impoundments, and other water storage or conveyance structures have been

[21] Rapport, D. J., & Whitford, W. G. (1999). How Ecosystems Respond to Stress. BioScience, 49(3), 193–203. See DCN 10–4871.

constructed at the cost of terrestrial, aquatic, and wetland habitats. The main impacts of aquatic habitat loss are a reduction in the number of fish in the environment, a concentration of fishery spawning and nursery areas in fewer locations, shifts in species dominance based on available habitat and local extirpation of historical fish species. Habitat loss in shoreline areas exacerbates the effect of CWIS losses because many fish species affected by IM&E rely heavily on coastal wetlands as nursery areas.

2. Water Quality and Impaired Waters

Poor water quality is a major stressor of aquatic biota and habitats. Degraded surface water and sediment contaminants reflect both current and past industrial, agricultural and urban land use and disposal practices. Poor water quality can limit the numbers, composition, and distribution of fish and invertebrates; reduce spawning effort and growth rates; select for pollution-tolerant species; cause periodic fishkills; or result in adverse bioaccumulative effects to piscivorous wildlife.

EPA has determined that the majority of surveyed facilities, including 71 percent of electric generators and 79 percent of sampled manufacturing facilities, are within two miles of an impaired (i.e., CWA section 303(d)-listed) waterbody.[22] These impairments are caused by a variety of chemical, physical, and biological factors. These factors include biological stressors, nutrients, organic enrichment/loading, bioaccumulation, toxics, unknown causes, and other forms of anthropogenic sources of pollution (e.g., atmospheric deposition of mercury leading to fish advisories). The combined impacts of impaired water quality may result in highly degraded or altered aquatic communities that are further impaired by IM&E associated with the operation of regulated facilities.

3. Overharvesting

Overharvesting is a general term describing the exploitation of an aquatic population beyond a level that is sustainable, sometimes to the point of significantly reducing the population relative to historic levels. Given that many fisheries regulated by the National Marine Fisheries Service (NMFS) are overfished on a continual basis, overharvesting is a particular problem for stocks also subject to IM&E.

[22] Abt Associates, Inc. (2010). Source Water Body Comparisons (Under Work Assignment 2–09, Task 4) (pp. 13). Cambridge, MA. See DCN 10–4504.

4. Invasive Species

Non-indigenous invasive species (NIS) are a significant and increasingly prevalent stressor in both freshwater and marine environments. Approximately 300 NIS have become established in marine and estuarine habitats of the continental U.S., and the number of NIS continues to increase. Many NIS are nuisance species with undesirable effects on local communities.[23] For example, interactions between NIS and other anthropogenic stressors can affect the colonization and distribution of native species subject to CWIS impacts.

C. Effects of CWIS on Aquatic Ecosystems

The magnitude and regional importance of IM&E is a function of operational CWIS intake volumes and characteristics of the aquatic community in the region. Thus, for example, IM&E can contribute to impacts on threatened and endangered (T&E) species and reduce populations of ecologically critical aquatic organisms, including important organisms in an ecosystem's food web. In addition, IM&E may diminish the compensatory reserves of populations and reduce indigenous species populations, commercial fisheries, and recreational fisheries. Further, IM&E may stress overall communities and ecosystems, as evidenced by reductions in diversity or other changes in ecosystem structure or function. The direct and indirect impacts of CWIS may reduce other valuable ecosystem goods and services, including nutrient cycling and ecosystem stability.

1. Losses of Fish From Impingement Mortality and Entrainment

The most visible direct impacts of IM&E are the losses of large numbers of aquatic organisms, distributed non-uniformly among fish, benthic invertebrates, phytoplankton, zooplankton, and other susceptible aquatic taxa (e.g., sea turtles). These losses have immediate and direct effects on the population size and age distribution of affected species, and may cascade through food webs.

In some cases, IM&E has been shown to be a significant source of anthropogenic mortality of depleted stocks of commercially targeted species. For example, approximately 5.4 percent of the estimated A1E population of the Southern New England/Massachusetts stock of winter flounder (*Pseudopleuronectes americanus*) is lost to IM&E.[24] In addition to its effect on stocks of marine commercial fish species, IM&E increases the pressure on native freshwater species, such as lake whitefish (*Coregonus clupeaformi*) and yellow perch (*Perca flavescens*), whose populations have seen dramatic declines in recent years.[25]

IM&E is also likely to contribute to reduced population sizes of species targeted by commercial and recreational fishers, particularly for stocks that are being harvested at unsustainable levels and/or undergoing rebuilding. Thus, reducing IM&E may lead to more rapid stock recovery, a long-term increase in commercial fish catches, increased population stability following periods of poor recruitment and, as a consequence of increased resource utilization, an increased ability to minimize the invasion of exotic species.[26]

[23] Ruiz, G. M., Fofonoff, P. W., Carlton, J. T., Wonham, M. J., & Hines, A. H. (2000). Invasion of Coastal Marine Communities in North America: Apparent Patterns, Processes, and Biases. Annual Review of Ecology & Systematics, 31, 481–531. See DCN 10–4880.

2. IM&E Effects on Threatened and Endangered Species

Populations of T&E (threatened and endangered) species may suffer increased mortality as direct or indirect consequences of IM&E. T&E species are vulnerable to future extinction or at risk of extinction in the near future and IM&E losses could either lengthen population recovery time, hasten the demise of these species, or counteract the effects of other conservation efforts. For this reason, the population-level and societal values of T&E losses are likely to be considered more important than the absolute number of losses that occur. Due to low population sizes, I&E mortality from CWISs may represent a substantial portion of the annual reproduction of T&E species.

3. Thermal Effects

One byproduct of once-through cooling water systems is a discharge of a heated effluent. Concerns about the impacts of heated effluents are

[24] Northeast Fisheries Science Center (NEFSC) of the NOAA National Marine Fisheries Service. (2011). 52nd Northeast Regional Stock Assessment Workshop (52nd SAW): Assessment Summary Report. DCN 12–4940.

[25] U.S. Department of the Interior (USDOI). (2004). Fisheries: Aquatic and Endangered Resources from *http://www.glsc.usgs.gov/main.php?content=research_risk&title=Species%20at%20Risk0&menu=research* [Retrieved June 23, 2004]; Wisconsin Department of Natural Resources (Wisconsin DNR). (2003). Adrift on the sea of life. Wisconsin Natural Resources, June, 17–21. See DCN 10–4914.

[26] Stachowicz, J. J., & Byrnes, J. E. (2006). Species Diversity, invasion success, and ecosystem functioning: disentangling the influence of resource competition, facilitation, and extrinsic factors. Marine Ecology—Progress Series, 311, 251–262. See DCN 10–4892.

addressed by state water quality standards addressing temperature, rather than a national rule. Section 316(a) of the Clean Water Act provides a mechanism for variances from controls that could be imposed due to thermal effects. Based on a limited review of NPDES permits, to the extent that facilities have controls on cooling water intake structures, these controls have been required to meet water quality standards related to temperature.[27]

Thermal pollution has long been recognized as having multiple effects upon the structure and function of ecosystems.[28] Numerous studies have shown that thermal discharges may substantially alter the structure of the aquatic community by modifying photosynthetic, metabolic, and growth rates[29] and reducing levels of DO. Thermal pollution may also alter the location and timing of fish behaviors including spawning, aggregation, and migration, and may result in thermal shock-induced mortality for some species.[30] Adverse temperature effects are likely to be more pronounced in aquatic ecosystems that are already subject to other environmental stressors such as high biochemical oxygen demand (BOD) levels, sediment contamination, and pathogens. Reduced waterbody volume due to the effects of climate change and/or lengthy droughts could exacerbate these effects.

4. Chemical Effects

The release of chemicals in the discharge of once-through cooling waters is another environmental effect associated with industrial facility operations. These chemicals include metals from internal corrosion of pipes, valves and pumps (e.g., chromium, copper, iron, nickel, and zinc), additives (anti-corrosion and anti-scaling agents) and their byproducts, and materials from boiler blowdown and cleaning cycles. In addition to these pollutants, facilities also discharge anti-fouling biocide agents.

A review of the effects of chemical treatment and discharge into the environment suggests that direct ecotoxicity in discharge plumes is rarely observed beyond the point of discharge or in a mixing zone near the pipe outlet.[31] However, the presence of these chemicals in the receiving water may be additive to low-level chronic adverse effects from other anthropogenic stressors identified above.

5. Effects of Flow Alteration

The operation of CWISs and discharge returns significantly alter patterns of flow within receiving waters both in the immediate area of the CWIS intake and discharge pipe, and in mainstream waterbodies, particularly in inland riverine settings. In ecosystems with strongly delineated boundaries (i.e., rivers, lakes, enclosed bays, etc.), CWISs may withdraw and subsequently return a substantial proportion of water available to the ecosystem. Even in situations when the volume of water downstream of regulated facilities changes relatively little, the flow characteristics of the waterbody, including turbulence and water velocity, may be significantly altered.

Altered flow velocities and turbulence may lead to several changes in the physical environment. These changes can include sediment deposition, sediment transport, and turbidity, each of which plays a role in the physical structuring of ecosystems.[32] Flow velocity and turbulence are controlling biological factors in aquatic ecosystem health, and have been shown to alter feeding rates, settlement and recruitment, bioturbation, growth and population dynamics.[33]

Climate change is predicted to have variable effects on future river flow in different regions of the United States. Some rivers are expected to have large increases in flood flows while other basins will experience stress from low water levels. Thus, the adverse effects of flow alteration may increase or decrease over longer periods for larger rivers, depending on their location.

D. Community-Level or Indirect Effects of CWIS

In addition to the direct effects of CWISs, IM&E may alter a wide range of aquatic ecosystem functions and services at the community level. Many of these effects on aquatic community function and service are poorly characterized, given the limited scope of IM&E studies and an incomplete knowledge of baseline or pre-operational conditions within affected waters.

The operation of CWISs by facilities can lead to localized areas of depressed fish and shellfish abundance. Industrial facilities (and the intake volume they represent) are located in a non-uniform manner along coastlines and rivers. They may be clustered, such that the populations affected by IM&E are geographically heterogeneous. This can result in a highly localized and patchy distribution of aquatic organisms in regional areas.

IM&E may directly reduce species populations through the death of individual organisms, or may indirectly affect species populations by altering established predator-prey relationships and thereby disrupting ecological niches and food webs. For example, the loss of young-of-year predators, such as striped bass, or loss of important forage fish, such as menhaden and bay anchovy, may affect trophic relationships and alter food webs. IM&E may lead to reductions in local community biodiversity or in a loss of genetic diversity in individual fish populations. Because IM&E represents a selective pressure on early life stages, it may reduce the genetic diversity of resident fish and prevent the recovery of depleted stocks.[34] Also, because many stocks are differentiated by oceanic region and/or timing of migratory movements, IM&E could alter the seasonal migration and life cycle events of fish populations, which could have ramifications for predator species.

IM&E may also alter the pace of nutrient cycling and energy transfer through food webs. Fish species have been shown to have substantial effects on nitrogen, phosphorous, and carbon cycling due to storage and translocation effects.[35] These alterations in nutrient cycling could lead to redirection of nutrient flows to other components of the ecosystem including water column phytoplankton, benthic macroalgae and attached epiphytes, with subsequent changes to the condition of critical

[27] Abt Associates, Inc. (2010). Source Water Body Comparisons (Under Work Assignment 2–09, Task 4) (pp. 13). Cambridge, MA. See DCN 10–4504.

[28] Abt Associates, Inc. (2009). Summary of Ecological Effects of Thermal Discharge (pp. 28). Cambridge, MA. See DCN 10–4505.

[29] Martinez-Arroyo, A., Abundes, S., González, M. E., & Rosas, I. (2000). On the Influence of Hot-Water Discharges on Phytoplankton Communities from a Coastal Zone of the Gulf of Mexico. Water, Air & Soil Pollution, 119(1–4), 209–230. See DCN 10–4820.

[30] Smythe, A. G., & Sawyko, P. M. (2000). Field and laboratory evaluations of the effects of 'cold shock' on fish resident in and around a thermal discharge: an overview. Environmental Science & Policy, 3(S1), 225–232. See DCN 10–4887.

[31] Taylor, C. J. L. (2006). The effects of biological fouling control at coastal and estuarine power stations. Marine Pollution Bulletin, 53(1–4), 30–48. See DCN 10–4901.

[32] Hoyal, D. C. J. D., Atkinson, J. F., Depinto, J. V., & Taylor, S. W. (1995). The effect of turbulence on sediment deposition. Journal of Hydraulic Research, 33(3), 349–360. See DCN 10–4797.

[33] Sanford, E. B., Bertness, D., & M. D. Gaines, S. D. (1994). Flow, food supply and acorn barnacle population dynamics. Marine Ecology Progress Series, 104, 49–62. See DCN 10–4882.

[34] Swain, D. P., Sinclair, A. F., & Mark Hanson, J. (2007). Evolutionary response to size-selective mortality in an exploited fish population. Proceedings of the Royal Society B: Biological Sciences, 274(1613), 1015–1022. See DCN 10–4900.

[35] Vanni, M. J., Layne, C. D., & Arnott, S. E. (1997). ''Top-down'' trophic interactions in lakes: effects of fish on nutrient dynamics. Ecology, 78(1), 1–20. See DCN 12–5047.

ecosystem habitats, such as submerged aquatic vegetation.

The effect of long-term or chronic IM&E may lead to a decrease in ecosystem resistance and resilience [36] (i.e., ability to resist and recover from disturbance, including invasive species). That is, IM&E is likely to reduce the ability of ecosystems to withstand and recover from these ecosystem damages, whether those impacts are due to anthropogenic effects or natural variability.

E. Cumulative Effects of Multiple Facilities

Cumulative effects of CWISs are likely to occur if multiple facilities are located in close proximity and impinge or entrain aquatic organisms within the same source waterbody, watershed system, or along a migratory pathway of a specific species (e.g., striped bass in the Hudson River). EPA analyses show more than 20 percent of all facilities on inland waters withdraw more than 5 percent of the mean annual flow.[37] See TDD Chapter 4.1.3 for detailed discussion. This impact is compounded because more than half of all regulated facilities are located on waterbodies with multiple CWISs. An inspection of the geographic locations of regulated facilities (approximated by CWIS latitude and longitude) shows that facilities in inland settings are more likely to be located in close proximity to other facilities (upstream or downstream) than are facilities in marine and estuarine environments. The cumulative impact of clustered facilities may be significant, due to the concentrated IM&E, combined intake flows, and the potential for other impacts such as thermal discharges.

IV. Summary Description of the Final Rule

Under today's final rule, the owners or operators of existing facilities and new units at existing facilities are subject to BTA standards for impingement mortality and entrainment that are expected to substantially reduce the adverse environmental impacts of cooling water intake structures. Earlier, in Section I, the preamble describes what facilities are subject to the rule. The discussion below presents an overview of the substantive requirements of the rule.

A. BTA Standard for Impingement Mortality for Existing Units at Existing Facilities

The final rule requires that existing facilities subject to this rule must comply with one of the following seven alternatives identified in the national BTA standard for impingement mortality at § 125.94(c) (hereafter, impingement mortality standards):

(1) Operate a closed-cycle recirculating system as defined at § 125.92;

(2) operate a cooling water intake structure that has a maximum through-screen design intake velocity of 0.5 fps;

(3) operate a cooling water intake structure that has a maximum through-screen intake velocity of 0.5 fps;

(4) operate an offshore velocity cap as defined at § 125.92 that is installed before October 14, 2014;

(5) operate a modified traveling screen [38] that the Director determines meets the definition at § 125.92(s) and that the Director determines is the best technology available for impingement reduction;

(6) operate any other combination of technologies, management practices and operational measures that the Director determines is the best technology available for impingement reduction; or

(7) achieve the specified impingement mortality performance standard.

Options (1), (2) and (4) above are essentially pre-approved technologies requiring no demonstration or only a minimal demonstration that the flow reduction and control measures are functioning as EPA envisioned. Options (3), (5) and (6) require more detailed information be submitted to the Director before the Director may specify it as the requirement to control impingement mortality.

In the case of Option (3), which EPA considers to be a streamlined alternative, the facility must submit information to the Director that demonstrates that the maximum intake velocity as water passes through the structural components of a screen measured perpendicular to the screen mesh does not exceed 0.5 feet per second.

In the case of Option (5), the facility must submit a site-specific impingement technology performance optimization study that must include two years of biological sampling demonstrating that the operation of the modified traveling screens has been optimized to minimize impingement mortality. As discussed below, if the facility does not already have this technology installed and chooses this option, the Director may postpone this study till the screens are installed (see VI.G.1.d below).

In the case of Option (6), the facility must submit a site-specific impingement study including two years of biological data collection demonstrating that the operation of the system of technologies, operational measures and best management practices has been optimized to minimize impingement mortality. If this demonstration relies in part on a credit for reductions in the rate of impingement already achieved by measures taken at the facility, an estimate of those reductions and any relevant supporting documentation must be submitted. The estimated reductions in rate of impingement must be based on a comparison of the system to a once-through cooling system with a traveling screen whose point of withdrawal from the surface water source is located at the shoreline of the source waterbody.

The impingement mortality performance standard in (7) requires that a facility must achieve a 12-month impingement mortality performance of all life stages of fish and shellfish of no more than 24 percent mortality, including latent mortality, for all non-fragile species that are collected or retained in a sieve with maximum opening dimension of 0.56 inches [39] and kept for a holding period of 18 to 96 hours. The Director may, however, prescribe an alternative holding period. The 12-month average of impingement mortality is calculated as the sum of total impingement mortality for the previous 12 months divided by the sum of total impingement for the previous 12 months. A facility must choose to demonstrate compliance with this requirement for the entire facility, or for each individual cooling water intake

[36] Folke, C., Carpenter, S., Walker, B., Scheffer, M., Elmqvist, T., Gunderson, L., & Holling, C. S. (2004). Regime Shifts, Resilience, and Biodiversity in Ecosystem Management . . . Annual Review of Ecology, Evolution, & Systematics, 35(1), 557–581. See DCN 10–4770.

[37] As described in the Phase I proposed rule (65 FR 49060) and the Phase II NODA (66 FR 28853), absent any other controls, withdrawal of a unit volume of water from a waterbody will result in the entrainment of an equivalent unit of aquatic life (such as eggs and larval organisms) suspended in that volume of the water column. Thus, facilities withdrawing greater than 5 percent of the mean annual flow from freshwater rivers and streams may entrain equal proportions of aquatic organisms.

[38] EPA is aware that innovative screen designs are currently being tested that are expected to provide similar or better performance than modified Ristroph traveling screems. Therefore EPA has defined modified traveling screen at 40 CFR 125.92 to mean any traveling water screen that incorporates the specified measures that are protective of fish and shellfish. In this preamble, modified traveling water screen with a fish handling and return system is often referred to more simply a modified traveling screen.

[39] Though less common, the EPA recognizes that ½ by ¼ inch mesh are used in some instances and perform comparably to the ⅜ inch square mesh. Therefore, today's rule allows for facilities to apply a ½ by ¼ inch sieve (diagonal opening of 0.56 inches) or a ⅜ inch sieve (diagonal opening of 0.53 inches) when discerning between impinged and entrained organisms.

structure. Biological monitoring must be completed at a minimum frequency of monthly.

The owner or operator of an existing facility must meet the impingement mortality requirements as soon as practicable after issuance of a final permit establishing the entrainment requirements under § 125.94(d).

Today's final rule also allows the Director, based on review of site-specific data, to conclude that a de minimis rate of impingement exists and therefore no additional controls are warranted to meet the BTA impingement mortality standard. In addition, today's final rule allows the Director flexibility in determining appropriate site-specific controls that may be less stringent than those found at § 125.94(c)(1) to (7) for existing units at existing facilities operating with a capacity utilization of less than 8 percent averaged over a 24-month block contiguous period. This provision can be found at § 125.94(c)(12). EPA notes that these provisions for impingement mortality would not apply to entrainment because, as discussed in the next section, the requirements for entrainment are established by the Director on a site-specific basis.

B. BTA Standard for Entrainment for Existing Units at Existing Facilities

The final rule establishes the national BTA standard for entrainment at existing units at existing facilities at § 125.94(d) (hereafter, entrainment standards). For such units, the rule does not prescribe a single nationally applicable entrainment performance standard but instead requires that the Director must establish the BTA entrainment requirement for a facility on a site-specific basis. The requirements must reflect the Director's determination of the maximum reduction in entrainment warranted after consideration of all factors relevant to the BTA determination at the site and must include consideration of the specific factors spelled out in § 125.98(f)(2). Facilities that withdraw greater than 125 mgd AIF must develop and submit an Entrainment Characterization Study (§ 122.21(r)(9)), as well as provide other information required at § 122.21(r)(7) and (10), (11), (12) and (13) that must include specified data pertinent to consideration of several of the factors identified in § 125.98(f).

C. BTA Standards for Impingement Mortality and Entrainment for New Units at Existing Facilities

The owner or operator of a new unit at an existing facility must achieve one of two compliance alternatives under the national BTA standards for impingement mortality and entrainment for new units at existing facilities at § 125.94(e) (hereafter, new unit standards).[40] Under the new unit standards, the owner or operator of a facility must reduce AIF at the new unit, at a minimum, to a level commensurate with that which can be attained by the use of a closed-cycle recirculating system as defined at § 125.92(c)(1). The owner or operator of a facility with a cooling water intake structure that supplies cooling water exclusively for operation of a wet or dry cooling tower(s) and that meets the definition of closed-cycle recirculating system at § 125.92(c)(1) meets this new unit standard. Under the alternative new unit standard, the owner or operator of a facility must demonstrate to the Director that it has installed, and will operate and maintain, technological or other control measures that reduce the level of adverse environmental impact from any cooling water intake structure used to supply cooling water to the new unit to a comparable level to that which would be achieved through flow reductions commensurate with the use of a closed-cycle recirculating system. Under this alternative, the owner or operator of a facility must demonstrate entrainment mortality reductions that are equivalent to 90 percent or greater of the reduction that could be achieved through compliance with the first alternative entrainment standard for new units.

The new unit entrainment standards do not apply to certain water withdrawals including (1) cooling water used by manufacturing facilities for contact cooling purposes; (2) portions of those water withdrawals for auxiliary cooling uses totaling less than 2 mgd; (3) any volume of cooling water withdrawals used exclusively for make-up water at existing closed-cycle recirculating systems;[41] and (4) any quantity of emergency back-up water flows. Furthermore, as is the case for existing units, obtaining cooling water from a public water system, using reclaimed water from wastewater treatment plants, or desalination plants, or using recycled process wastewater effluent as cooling water does not constitute use of a cooling water intake structure. The new unit requirements apply only to the volume of cooling water used by the new unit, or to the cooling water intake structures used by the new unit. The new unit requirements do not apply to the rest of the existing facility.

In addition, the Director may establish alternative entrainment requirements for new units when compliance with the new unit entrainment standards would result in compliance costs wholly out of proportion to the costs EPA considered in establishing the requirements at issue or will result in significant adverse impacts on local air quality, significant adverse impacts on local water resources other than impingement or entrainment, adverse impacts on threatened and endangered species, or significant adverse impacts on local energy markets. Any Director-specified alternative must achieve a level of performance as close as practicable to the requirements of § 125.94(e)(1) or (2).

D. Other Provisions

The final rule contains a number of other provisions related to the BTA impingement and entrainment reduction requirements. For example, the rule also provides that the Director may establish more stringent requirements as BTA if the Director determines that the facility owner or operator's compliance with the requirements otherwise established under the final rule would not meet the requirements of applicable State and Tribal law, including water quality standards. 40 CFR 125.94(i). Today's rule also requires the owner or operator of a facility subject to this subpart to submit and retain permit application and supporting information as specified in § 125.95; monitor for compliance as specified in § 125.96; and report information and data and keep records as specified in § 125.97. Director requirements are specified in § 125.98.

The rule further provides that, in the case of a nuclear facility or a facility constructing or conducting maintenance on nuclear powered vessels of the Armed Services, if the owner or operator of the facility demonstrates to the Director, upon the Director's consultation with the Nuclear Regulatory Commission, the Department of Energy or the Naval Nuclear Propulsion Program, that compliance with this subpart would result in a conflict with a safety requirement established by these entities, the

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[40] EPA expects that all new units will comply with these requirements through the installation of a closed-cycle cooling system, which is one of the most effective technologies for reducing impingement and impingement mortality. Therefore, the IM requirements for new units are already addressed by the new unit requirements by virtue of the first compliance alternative of the IM performance standard.

[41] For facilities with a combination of closed-cycle recirculating systems and other cooling water systems, the entrainment mortality standard does not apply to that portion of cooling water withdrawn as make-up water for the closed-cycle recirculating system.

Director must establish BTA requirements that would not result in a conflict with the Commission's, the Department's or the Naval Nuclear Propulsion Program's safety requirement.

V. Summary of Data Updates and Revisions to the Proposed Rule

This description of revisions to the proposed rule is organized in three sections: Data updates, regulatory approach and compliance, and new units. EPA published two NODAs (Notice of Data Availability) (77 FR 34315, June 11, 2012 and 77 FR 34927, June 12, 2012) based on some comments received on the proposed rule and additional analyses. EPA also took public comment on the information in these notices.

A. Data Updates

On the basis of comments received, additional information made available, and further analyses, EPA revised a number of assumptions used in its assessments for the final rule. These included revisions to the engineering costs of options considered in development of the final rule, the information collection costs, the economic analyses, and the benefits analyses. The revised analyses, along with an explanation of how they affected decision making for this final rule, are discussed below.

1. Impingement Data and Performance Standard

Since publishing the proposal, EPA received a substantial number of comments stating the amount of data to develop the proposed impingement mortality performance standard was too limited. EPA received more than 80 additional documents containing impingement and entrainment data. EPA reviewed these materials and found that many documents did not provide useful data. For example, in some cases, a document did not provide useful information because the only data available were the facility name and raw sampling data for a number of different species of fish or shellfish, or both. In other cases, the documents focused on source water characterization data alone. However, after review, EPA identified more than 40 distinct sets of additional impingement sampling and performance data.

EPA also reevaluated and revised the criteria it used for including impingement mortality study data in the impingement mortality performance standard calculations. In calculating the impingement mortality performance standard of § 125.94(c)(7), EPA applied these revised criteria for acceptable data to both the new data and the earlier data used for proposal. EPA's approach for the final rule is similar to that of the proposal. In order to include data in EPA's calculation, for the proposal, EPA applied the following four criteria. First, the data must be specific to the technology under consideration. Second, impingement mortality must have been reported as an absolute number or a percentage of impinged fish that were killed. Third, the data must reflect that the installed technology was operated under conditions that are representative of actual conditions at a facility, and fourth, the reported values must be actual measurements. EPA based the proposed performance standard on the performance of modified traveling screens with a fish return system using a limited definition of the control technology.

In its reevaluation and based on comments, EPA decided to revise some of the criteria and add two new ones. In some cases, the effect of these changes is to relax the criteria and in others, to impose more restrictive criteria. First, all impingement data must be for non-fragile species (including shellfish). Second, the data must be representative of annual mortality data for purposes of deriving an annual performance standard. EPA notes that in contrast to the proposed rule, the permit application does not require submission of the proposed list of ''species of concern.'' EPA found that the term ''species of concern'' was similar to terms used in the context of T&E (threatened and endangered) species, and may further cause confusion over existing Services or State requirements for such species. Further, despite EPA's efforts to distinguish between species of concern and RIS (representative indicator species) in the NODA (77 FR 34325, June 11, 2012), EPA found that many commenters were still confused by the language. Instead, EPA is adopting the term ''fragile species'' and using the term exactly as it is used with the impingement mortality data and criteria used in calculating the impingement mortality performance standard of the rule. EPA included a definition for ''fragile species'' at § 125.92(m), as a species of fish or shellfish that has an impingement survival rate of less than 30 percent. EPA took this approach to ensure that a facility's performance in reducing impingement mortality as demonstrated by collecting biological data would reflect only the effects of its improvements to the CWIS technology, and not be confounded by effects of data collection that are not caused by impingement.

EPA also relaxed the holding time criteria as a result of reevaluating the range of acceptable impingement mortality holding times, which at proposal was limited to 24 to 48 hours. After evaluating the data, EPA concluded that a range of holding times of 18 to 96 hours was acceptable for inclusion in the development of a performance standard because commenters had provided documentation showing that the actual time period typically had little effect on IM rates. At proposal, EPA counted all fish that died at any time during the holding period. For the final rule being promulgated today, EPA excludes those that were dead at time zero because such counts measured immediate deaths and not those organisms that were mortally harmed as a result of impingement. These counts also might reflect already injured, nearly dead, or already dead fish (''naturally moribund'') that were impinged by the screen. As a consequence of relaxing the holding times and other requirements, EPA based the performance standard on a larger set of data, with broader geographic representation. (For more information, see DCN 12–6703.) The rationale for these revisions to the data acceptance criteria are described in further detail in the TDD, Chapter 11. Using the revised criteria, EPA reviewed the data in each of the impingement mortality studies for potential inclusion in EPA's evaluation of an impingement mortality performance standard. These changes resulted in an increase in the number of facility data sets acceptable for determining the impingement mortality performance standard, from four data sets at three facilities at proposal to 26 data sets at 17 facilities today. As a result, the 12-month average impingement mortality performance standard of all life stages of fish and shellfish was revised from no more than 12 percent to no more than 24 percent mortality, including latent mortality, for each non-fragile species that is collected or retained in a sieve with maximum opening dimension of 0.56 inches and kept for a holding period of 18 to 96 hours. The revised performance standard and data evaluation criteria are discussed in detail in Section VI and Chapter 11 of the TDD.

EPA also reevaluated its approach to compliance monitoring for the impingement mortality performance standard. In particular, EPA considered the costs and burden of frequent biological monitoring for those technologies that, according to EPA's record, perform equal to or better than the IM performance standard. As proposed, all facilities would have conducted weekly biological monitoring in perpetuity irrespective of the compliance approach or technologies selected. EPA agrees with comments that this may be unnecessarily burdensome and of limited value for those technologies for which the potential performance is well documented. As such, today's final rule includes seven compliance alternatives, only one of which requires biological compliance monitoring.

EPA notes, however, that a facility relying in part on a credit for reductions in impingement mortality already obtained at the facility (§ 125.94(c)(6)) must gather biological data at a minimum frequency of monthly for a period of two years in order to calculate their 12-month average impingement mortality. Further, a facility choosing to comply using the impingement mortality performance standard (§ 125.94(c)(7)), must conduct biological monitoring at a frequency of at least monthly in order to calculate its 12-month average impingement mortality. The 12-month average is calculated as the sum of total impingement mortality for the previous 12 months divided by the sum of total impingement for the previous 12 months. EPA is requiring that a facility choose to either demonstrate compliance with this requirement for the entire facility, or for each individual cooling water intake structure. The EPA expects that as the performance of the technology is demonstrated by the facility, the Director could reduce the frequency of biological compliance monitoring. Further, prior to a subsequent permit application, a facility could collect sufficient performance data to demonstrate to the satisfaction of the Director that its ''systems of technologies'' compliance alternative is BTA at that facility.

2. Technology Costs

Since publishing the proposal, EPA received a number of public comments from industry stating that EPA had underestimated the costs of modified traveling screens with fish returns. EPA used new information to revise the compliance cost estimates (including the methodology used for technology assignment) and the capital costs for several compliance technologies, including those used as the primary basis for the final rule. Those changes include the following:

- In response to comments challenging EPA's assumption that modified traveling screens were available at most facilities, EPA changed the assignment of the modified traveling cost module [42] so as to apply this only where the existing intake for the model facility intake employed traveling screens. As a result, a number of intakes, such as those that use passive screens (e.g., fixed screens), were assigned higher cost technologies such as larger intakes or wedgewire screens with through-screen design velocities of 0.5 fps.
- Because EPA has clarified that properly operated closed-cycle recirculating systems is one of the compliance alternatives for impingement mortality, those intakes with existing closed-cycle cooling no longer receive additional impingement technology costs.
- At proposal, the design of the larger intake module was based on a through-screen velocity of 1.0 fps and, therefore, was not consistent with the low velocity compliance alternatives. To ensure that this technology will be consistent at all locations, the through-screen design velocity for the larger intake was changed to a maximum of 0.5 fps, resulting in a substantial increase in capital and operational and maintenance costs.
- EPA received a number of comments noting that fish returns might be difficult to install at some intakes. EPA reviewed the fish return cost component of the modified traveling screen module and concluded that EPA's costs represented an ''easy'' installation rather than an average of both easy and more difficult installation costs. To account for a wider range of fish return costs that includes those with higher costs, EPA increased the capital costs of the fish return component and included additional costs for those with particularly difficult circumstances such as very long intake canals and submerged offshore intakes. For a detailed discussion, see Chapter 8 of the TDD.
- EPA received a number of comments stating that it had underestimated capital costs for modified traveling screens. During site visits to several facilities, EPA obtained actual traveling screen replacement costs. EPA compared its estimates to actual reported replacement costs and vendor-supplied data and concluded that the capital costs were underestimated by about 20 percent. Therefore, EPA increased the capital costs of modified traveling screens by 20 percent.

These changes to the engineering costs result in a 24 percent increase in capital and O&M costs. The revised costing assumptions are discussed in further detail in Chapter 8 of the TDD.

3. Monitoring Costs for Impingement Mortality

Many commenters expressed concern that requirements for monitoring for the impingement mortality performance standard were excessive. Of particular concern were the long-term costs for impingement mortality monitoring at facilities that would be relying on either closed-cycle cooling or an intake velocity less than or equal to 0.5 fps through-screen design velocity. The final rule includes seven compliance alternatives for the impingement standard. One of these alternative provides for reduced monitoring requirements for facilities employing modified traveling screens. This alternative is available if the facility has demonstrated the technology is optimized to minimize impingement mortality of all non-fragile species. Under this approach, EPA requires the facility to provide site-specific performance data to identify the operational conditions that will ensure that the technology is being operated optimally. Once these operational conditions have been identified, the Director must include in the permit those operational measures and best management practices identified in the study and deemed as necessary by the Director to ensure proper operation of the modified traveling screens. EPA also clarified in the rule that compliance monitoring and reporting requirements for facilities that comply with the impingement mortality standard by employing one of the pre-approved or streamlined IM compliance alternatives will be largely limited to information that ensures proper operation of the installed control technology. EPA estimates that this alternative approach will reduce annual monitoring and reporting costs from approximately $47 million under the proposed rule to approximately $27 million under the final rule.

4. Benefits and Willingness To Pay Survey

EPA received a number of comments on the proposed rule and NODA addressing the use of stated preference surveys to determine the public's willingness-to-pay for benefits associated with the rule. EPA conducted a stated preference survey to calculate benefits associated with minimizing

[42] EPA used a model facility approach to develop compliance technology costs where different sets of compliance technology cost algorithms called modules were assigned to individual model facility intakes on the basis of site-specific conditions. For a more detailed discussion, see the TDD Chapter 8.

adverse impacts to aquatic ecosystems from cooling water intakes. For some commenters, the use of stated preference surveys to evaluate benefits remains controversial, and they objected to using such surveys. Other commenters acknowledge the decades of technical development and improvement of these methods and support using stated preference surveys. Based on consideration of public comment, EPA decided not to employ the survey results for purposes of decision-making in this rule, or include them in assessing the total benefits of the rule. The rule does not require State Directors to require facility owners or operators to conduct or submit a willingness to pay survey to assess benefits.

B. Regulatory Approach and Compliance

1. Regulatory Approach

EPA has largely adopted the regulatory approach of the proposed rule with several changes regarding compliance, particularly with respect to the impingement mortality requirements. These changes clarify elements of the rule (as discussed in the NODAs) about which commenters expressed uncertainty and provide additional flexibility to regulated facilities in meeting the rule's impingement mortality standard.

EPA received some comments questioning whether specific provisions apply to the entire facility or to individual intakes. To clarify this issue, EPA modified the rule language so as to state clearly that a facility with multiple intakes must decide whether it will adopt a single compliance strategy for impingement mortality for the entire facility or adopt an intake-specific compliance strategy at each cooling water intake. Thus, facilities may select different compliance strategies for different intakes, providing flexibility at facilities with multiple intakes. Regardless of which impingement compliance approach a facility chooses (single strategy for entire facility or different strategies for different intakes), if the facility chooses to comply with the impingement standard by operating at a maximum through-screen velocity of 0.5 feet per second, the facility must measure and comply with the low velocity compliance alternative of 0.5 fps on an individual intake basis.

a. Impingement Mortality Standards

EPA received a substantial number of comments requesting greater flexibility and clarification regarding compliance with the impingement mortality standards, including suggestions that (1) impingement requirements be addressed on a site-specific basis; (2) certain technologies should be pre-approved; (3) credit should be given for existing technologies and operating conditions; and (4) combinations of technologies be allowed. EPA has concluded that low-cost technologies for impingement mortality reduction are effective, widely available, feasible, and demonstrated for facilities nationally and thus, a completely site-specific approach is not appropriate. However, recognizing that for some sites technologies other than modified traveling screens may allow a facility to achieve the same level of performance, EPA has included compliance options that provide for more flexibility and allow consideration of the performance of combinations of technologies and operating conditions. Some of the more significant changes include the following:

- *Compliant technologies*—EPA has concluded that employing certain technologies will meet or exceed the requirement of the impingement mortality standard, provided they meet certain design and operational criteria. These pre-approved and streamlined technologies include a closed-cycle recirculating system, existing offshore velocity cap, and maximum design intake velocity of 0.5 fps. Associated with these compliance options are reduced monitoring requirements.
  - *Closed-Cycle Cooling*—EPA has concluded that a fully closed-cycle recirculating system as defined at § 125.92(c) (and that is properly operated and maintained) achieves the impingement mortality performance standard. Even after retrofitting a facility to be closed-cycle, it may still be possible to withdraw and discharge cooling water at rates associated with once-through cooling. Existing facilities that retrofit to closed-cycle cooling often do so without modifying or replacing their condenser to optimize it for closed-cycle operation. In such cases, the facility has an incentive to operate its system in a once-through cooling mode, to minimize chemical costs or avoid a turbine backpressure constraint. EPA has concluded that it is not appropriate to add conditions to the definition of closed-cycle cooling because water may be withdrawn for purposes of replenishing losses to a closed-cycle recirculating system other than those due to blowdown, drift, and evaporation from the cooling system. However, the final rule provides the Director the discretion to determine whether the operation of a cooling system minimizes the make-up and blowdown flows withdrawn, consistent with the definition of a closed-cycle recirculating system (40 CFR 125.92(c)).
  - *Existing Offshore Velocity Caps*—The record indicates that an existing offshore velocity cap as defined at § 125.92(v) also achieves the necessary reductions in impingement mortality and thus meets the IM standard. Data in the record concerning existing velocity caps show that a velocity cap alone is insufficient, but data on existing offshore velocity caps shows that a velocity cap in combination with their current offshore locations meet EPA's BTA standard for impingement mortality. EPA has determined that new offshore velocity caps could comply using the combination of technologies approach in § 125.94(c)(6). The offshore component likely makes the velocity cap technology unavailable except to facilities in marine waters and certain Great Lakes locations; therefore, the technology alone is not BTA.
  - *Through-Screen Velocity*—EPA has clarified that compliance with a 0.5 fps intake velocity achieves the IM standards. EPA's record shows an intake velocity of 0.5 fps or lower provides similar or greater reductions in impingement, and therefore impingement mortality, than modified traveling screens—the technology forming the basis for the numeric impingement mortality performance standard that is the goal for all facilities. There are two ways to demonstrate compliance using intake velocity. First, an intake with a maximum design intake velocity less than or equal to 0.5 fps is pre-approved BTA for impingement mortality and does not require further monitoring. Alternatively, under a streamlined option, the facility may demonstrate to the Director that the facility meets the velocity requirement through monitoring of the actual intake velocity. Screen velocity can be monitored by direct measurement or by calculation using the volumetric actual intake flow and source water surface elevation.
- *Modified Traveling Screens*—A facility must operate modified traveling screens [43] that the Director determines meets the definition at § 125.92(s). Facilities will demonstrate that they have optimized performance of their traveling screen to minimize IM.

[43] While rotary screens are technically not modified traveling screens, the regulation at § 125.92(s) defines modified traveling screens to include traveling water screens that incorporate measures protective of fish and shellfish. EPA has thus provided the flexibility for other types of active screens that achieve the same or better performance than modified traveling screens.

• *Systems of Technologies to Meet the IM Standard*—EPA received a substantial number of comments asking whether previously installed technologies or various combinations of technologies and operating conditions could also meet the BTA standard for impingement mortality. For example, some technologies, such as louvers, reduce the rate of impingement, but the effect on overall impingement mortality reduction cannot easily be measured and would not appear in biological sampling of the technology. In EPA's view, the Director should take into account the reduction in impingement—for example, that associated with such technologies as louvers or behavioral deterrents, or due to intake location—when determining permit conditions to include in the facility's permit in order for a combination of technologies to achieve the required impingement mortality standards. Thus, the facility should obtain credit toward the impingement mortality standard for such reductions in the rate of impingement. A number of the flexibilities above were described in the June 11, 2012 NODA, and EPA has included a provision to allow additional flexibility in achieving compliance through the use of a combination of technologies and operating conditions. A facility may use a system of technologies, management practices and operational measures to achieve the impingement mortality standard, including, for example, flow reductions, seasonal operation, unit closures, credit for intake location, behavioral deterrent systems, and other technologies and operational measures. The Director must determine, based on a demonstration by the facility to the Director, that the system of technologies or operational measures, in combination, have been optimized to minimize impingement mortality of all non-fragile species. The Director may require additional operational measures, best management practices, and monitoring as part of the demonstration. In addition, the facility's permit must include conditions to ensure that the facility operates its cooling water intake structures in a manner consistent with the conditions and measures identified in its demonstration to the Director.

• *Numeric IM Performance Standard*—As a practical matter, EPA expects that very few facilities will choose to comply with the numeric impingement mortality performance standard. Those facilities that choose to comply in this way will need to demonstrate to the Director how the technology the facility is implementing enables the facility to meet the impingement mortality standard. The numeric standard provides a pathway to compliance for innovative technologies that may be developed in the future.

EPA also received many comments stating that barrier nets were both unnecessary and might be unavailable in many locations. Because EPA's revised impingement data set had sufficient data to characterize shellfish impingement, EPA has eliminated the barrier net requirement in the final rule. See Section VI for more information.

b. Definition of Closed-Cycle Cooling System

In the final rule, EPA revised the definition of a closed-cycle recirculating system to provide additional flexibility for the Director in determining which closed-cycle cooling systems comply with the IM standards. The proposed rule's definition of ''closed-cycle recirculating systems'' included, as elements of a properly operated closed-cycle system performance, requirements generally expressed in terms of cycles of concentration (COC) or percentage flow reduction relative to a once-through cooling system. Cycles of concentration represents the accumulation of dissolved minerals in the recirculated cooling water. Discharge of a portion of the water (called ''blowdown'') is used to control the buildup of these minerals. COC is a measure of how concentrated are chlorides in recirculated water relative to make-up water, and thus how well a system recycles intake water before replacing it with new withdrawals. This is not to be confused with cycles of flow, as some commenters appeared to do.

Cycles of concentration can be measured as the ratio of chloride levels in the recirculated water or blowdown relative to the chloride levels in the source water, or makeup water. Some commenters stated that, while they have been operating as closed-cycle units for many years, they were concerned that their facilities would not be ''closed-cycle recirculating systems'' under the proposed definition because they would not achieve the required COC. EPA has found the concentration cycles in the majority of cooling towers usually range from 3 to 6 at power plants, and can often exceed 9 at manufacturing facilities. However, EPA recognizes that many manufacturers have complex water balances, and calculating a specific flow reduction attributable to cooling water use could be difficult and time consuming. In such cases, many manufacturers could far more readily calculate the cycles of concentration of particular unit operations, and could therefore show those unit operations that use cooling water meet the conditions for closed-cycle cooling. EPA found in site visits many complex manufacturing facilities already have this capability, and have achieved very high COC. Likewise, power plants may find it much easier to measure flow than cycles of concentration. Accordingly, EPA's proposed rule attempted to recognize performance using either metric. EPA expects most power generators would use percentage flow reduction to demonstrate they are closed-cycle, and expects most manufacturing facilities would use COC for those units that utilize water for cooling purposes. Increasing the amount of minerals present in the water by cycling can make water less aggressive to piping; however, EPA is also aware that excessive levels of minerals (such as found in certain source waters, most notably those with higher salinity) can cause scaling problems, leading to different levels of both metrics for freshwater and saltwater facilities.

EPA carefully considered these issues and concluded that the most important aspect of the definition of a properly operated closed-cycle cooling system is that the makeup flow be minimized. Thus EPA has removed the numeric levels of the metrics as a threshold, while retaining the minimized makeup flow aspect of the definition. As an example, in the case of a facility that uses make-up water from a freshwater source, a Director may determine that a closed-cycle recirculating system can generally be deemed to minimize make-up and blowdown flows if it reduces actual intake flows (AIF) by 97.5 percent as compared to a once-through cooling system or if its cooling tower is operated at a minimum cycles of concentration of 3.0. And likewise, in the case of a facility that uses make-up water from a saltwater, brackish, or other source with a salinity of greater than 0.5 parts per thousand, a Director may determine that a closed-cycle recirculating system can generally be deemed to minimize make-up and blowdown flows if it reduces actual intake flows (AIF) by 94.9 percent as compared to a once-through cooling system or if its cooling tower is operated at a minimum cycles of concentration of 1.5. These reductions and cycles of concentration are illustrative. A Director may determine that other levels near these numbers could also constitute a closed-cycle recirculating system. The final rule further recognizes that in certain unavoidable circumstances, these levels for COC or percent flow reduction might not be achievable at all facilities. Such circumstances could include situations where water quality-based discharge limits might limit the concentration of a pollutant that is not readily treatable in the cooling tower blowdown or situations where varying source water quality could lead to unavoidable problems concerning scale formation, solids buildup, corrosion, or media fouling. Such facilities should demonstrate these circumstances to their Director and indicate the measures they have taken to minimize makeup flows. The Director will retain the discretion to conclude that the particular facility employs a closed-cycle recirculating system when the benchmarks are not met.

In cases where the Director will make a determination as to whether the facility's cooling system meets the definition of a closed-cycle recirculating system, EPA's intent is that the withdrawal of small amounts of service water (for uses such as fire suppression, potable water, screenwash water, vehicle wash water, and such) do not preclude consideration of the system as closed-cycle. To avoid misuse of this provision, the Director will make the final determination.

Finally, EPA data show more than 50 facilities have cooling systems that include impoundments. In some cases, the cooling systems that include impoundments were created in the waters of the U.S., in whole or in part, or were created in uplands but withdraw make-up water from waters of the U.S. These cooling systems may perform like a closed-cycle recirculating system. EPA has clarified at 40 CFR 125.92(c)(2) that a cooling system that includes an impoundment lawfully created in the waters of the U.S for the purpose of cooling may be considered a closed-cycle recirculating system. As with other closed-cycle recirculating systems, the Director will determine whether the impoundment minimizes the withdrawal of water for cooling purposes and therefore meets the definition of a closed-cycle recirculating system. See Section VI for further discussion.

c. Entrapment

The proposed rule included a prohibition on trapping organisms in an intake structure with no viable escape route. Many commenters expressed concern that the entrapment requirements were not well defined and would require costly technologies not considered in EPA's cost estimates. Moreover, in the commenters' view, the requirements could be difficult to comply with, particularly where cooling systems employ impoundments or basins downstream of the initial intake structure. EPA agrees that in some cases, such as where a canal or basin for maintaining consistent water levels is located behind the CWIS, that the proposed entrapment requirement could require additional controls such as additional fish returns that are not, in all cases, feasible. For example, EPA found in site visits that the forebay may be located more than a mile from the CWIS, and a fish return in that situation would not have been feasible. The final rule deleted the requirement that prohibited entrapment. In the final rule, facilities would account for all impinged fish and shellfish when conducting their two year performance study. To the extent entrapment of shellfish poses a concern, the Director may establish additional measures, such as seasonal deployment of barrier nets, under § 125.94(c)(8).

d. Requirements for Threatened and Endangered Species

EPA consulted with the Fish and Wildlife Service and National Marine Fisheries Service and EPA made a number of adjustments to the rule to protect threatened and endangered species and designated critical habitat as a result of the consultation; the protections were included to insure that the rule is not likely to jeopardize the continued existence of listed species or result in the destruction or adverse modification of designated critical habitat. To be clear, the ESA provisions of the rule extend to all listed T&E species, not just fish and shellfish. See Section VIII.K for a summary of these provisions.

2. Compliance Timelines for Impingement Mortality and Entrainment Requirements

At proposal, compliance deadlines for impingement mortality and entrainment requirements were set separately. Facilities would have been required to meet impingement mortality reduction requirements as soon as possible, but no more than eight years after the effective date of the rule. Compliance with entrainment reduction requirements would have been set by the Director. Many commenters expressed concern that the compliance timeline for the impingement mortality and entrainment requirements should be harmonized to prevent a facility from having to install a technology to comply with impingement mortality requirements, only to be required at a later date to install an entrainment reduction technology that effectively renders the investment in the impingement mortality technology obsolete or worthless.

EPA agrees that facilities required to install both impingement and entrainment compliance technologies will benefit from reduced compliance costs if the compliance scheduling is coordinated. EPA also agrees that requiring more timely decisions on entrainment requirements than anticipated at proposal will facilitate these cost savings without sacrificing fish protection. In some cases, impingement compliance can be attained with entrainment technologies. For example, the Director may determine that the installation of modified fine-mesh traveling screens and narrow-slot wedgewire screens will achieve the impingement mortality standard and further, that this same equipment represents, on a site-specific basis, BTA entrainment control. If the compliance schedule is not harmonized, it is possible that a facility could install (at significant cost) coarse-mesh traveling screens that it might have to later retrofit with fine-mesh panels. It is also possible that a facility could make modifications necessary to attain a 0.5-fps through-screen velocity to meet the IM standards and later have closed-cycle cooling identified as BTA for entrainment, thereby making the intake modifications for impingement control unnecessary.

To address this issue in the final rule, EPA revised the compliance requirements so that the Director is required first to establish entrainment requirements under § 125.94(b)(1) in the final permit. The facility will then be required to comply with the impingement mortality standard in § 125.94(c) as soon as practicable thereafter. See Section VIII on implementation for more detailed discussion.

Because an entrainment requirement could require controls that take many years to design, finance and construct, the Director may establish interim milestones related to meeting the final requirements to ensure that the facility is making progress.

C. New Units

EPA has revised the definition of new units to mean a stand-alone unit at an existing facility the construction of which is commenced after the effective date of today's final rule; consists of only a stand-alone unit constructed at an existing facility; and that does not otherwise meet the definition of a new facility at § 125.83. A stand-alone unit is a new, separate unit that is constructed at an existing facility. New unit includes stand-alone units that are added to a facility for purposes of the same general industrial operation as the existing facility. A new unit may have its own dedicated cooling water intake structure, or may use an existing or modified cooling water intake structure.

VI. Basis for the Final Regulation

In response to the Supreme Court's decision in *Entergy Corp.* v. *Riverkeeper, Inc. et al.* in April 2009, EPA has reevaluated the requirements for existing facilities under CWA section 316(b). As discussed above, EPA collected additional data and information to update its assessment of the efficacy of various technological measures for reducing IM&E and analyses prepared for the earlier rule-making efforts. EPA's additional technical rigor provided a strengthened analysis of different technologies for reducing IM and their effectiveness. As a result of its revised assessments and further consideration of the factors affecting the availability of different technology in a wide range of settings, EPA has decided not to re-promulgate requirements for existing facilities that mirror those of the final Phase II rule. Further, EPA is adopting, for the reasons explained in detail below, a new framework. In addition, as previously noted, EPA decided to address all existing facilities subject to section 316(b) in this rule (i.e., both those subject to the Phase II rule and some of those subject to the Phase III rule). For a brief description of the final rule, see Section IV.

A. EPA's Approach to BTA

CWA section 316(b) requires EPA to establish standards for cooling water intake structures that reflect the ''best technology available for minimizing adverse environmental impact.'' As explained above, the statute is silent with respect to the factors that EPA should consider in determining BTA, but courts have held that section 316(b)'s reference to CWA sections 301 and 306 is an invitation for EPA to look to the factors [44] considered in those sections in establishing standards for section 316(b).

But EPA, when considering such factors, is not bound to evaluate these in precisely the same way it considers them in establishing effluent limitations guidelines under CWA section 304. As the Supreme Court noted, given the absence of any factors specified in section 316(b), EPA has much more discretion in its standard setting under section 316(b) than under the effluent guidelines provisions. Therefore, the statute vests EPA with broad discretion in determining what is the ''best'' technology that is ''available'' for minimizing adverse environmental impact. As the Supreme Court has further explained, under section 316(b), the ''best'' technology ''available'' may reflect a consideration of a number of factors and ''best'' does not necessarily mean the technology that achieves the greatest reduction in environmental harm that the regulated universe can afford. Rather, the ''best'' (or ''most advantageous,'' in the court's words) technology may represent a technology that most efficiently produces the reductions in harm.

EPA interprets section 316(b) to require the Agency to establish a standard that will best minimize impingement and entrainment—the main adverse effects of cooling water intake structures not otherwise addressed by the other sections of the CWA (e.g., thermal discharges). In EPA's view, several important considerations underpin its decision. First, its BTA determination should be consistent with, and reflective of, the goals of CWA section 101: ''to restore and maintain the physical, chemical, and biological integrity of the Nation's waters,'' with the interim goal of ''water quality which provides for the protection and propagation of fish, shellfish, and wildlife and provides for recreation in and on the water.''

Second, E.O. 13563 directs EPA and other Federal agencies to identify and use the best, most innovative and least burdensome tools for achieving regulatory ends. In its regulatory actions, agencies ''must take into account benefits and cost, both quantitative and qualitative,'' and to the extent permitted by law, only promulgate regulations that are based on ''a reasoned determination that its benefits justify its costs (recognizing that some benefits and costs are difficult to quantify)'' (see section 1(b)(1)). In selecting a regulatory approach, agencies must tailor regulations to impose the least burden on society and, in choosing among regulatory alternatives, select ''those approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity)'' to the extent permitted by law. 76 FR 3821 (January 21, 2011). Because the Supreme Court has concluded that the CWA authorizes EPA to consider costs and benefits in its BTA determination, EPA has consequently considered costs and benefits in this final rule as directed by the President. In accord with E.O. 13563, EPA has concluded that the benefits of the final rule justify its costs. For additional discussion, see Section VI below.

Consideration of benefits is complicated by the debate about the tools and data that would permit a complete expression of ecological benefits in monetized terms. EPA has, however, used the best available science regarding widely accepted tools and data to monetize the benefits of the various options in four major categories: recreational fishing, commercial fishing, nonuse benefits, and benefits to threatened and endangered species (see Section X below). EPA has concluded that the benefits estimated for the first two categories are generally complete, while the benefits estimated for the latter two categories are far from being complete for a number of reasons. For example, the nonuse benefits transfer was based on a species that represents less than one percent of adverse environmental impacts. EPA is continuing to refine its tools to develop a more complete analysis concerning benefits for future application.

In selecting the ''best'' technology available for minimizing adverse environmental impact, EPA looked at a number of factors. As discussed previously, EPA's initial approach to 316(b) standard setting was similar to one it follows in considering a technology-based rule under sections 301, 304, and 306. EPA first considered the availability and feasibility of various technologies, and then evaluated costs associated with these technologies (including potential costs to facilities and households), and their economic impacts. EPA also reviewed the effectiveness of these technologies in reducing impingement mortality and entrainment. Further, EPA also considered additional factors set out in CWA section 304(b), including location, age, size, and type of facility. In addition, EPA considered the non-water quality environmental impacts of different technologies on energy production and availability, electricity reliability, and potential adverse environmental effects that could arise from the use of the different technologies evaluated.

As a result of this thorough evaluation, in the case of the BTA standard for impingement mortality, EPA based the standard on performance of well-operated modified traveling screens with a fish handling and return system as defined more specifically by the rule. Under the BTA IM standard, a facility has a number of options for

[44] The factors specifically delineated in CWA sections 301 and 306 include cost of the technology, taking into account the age of the equipment and facilities, process employed, engineering aspects associated with a particular technology, process changes and non-water quality environmental impact (including energy requirements).

compliance. In the case of the BTA standard for entrainment, on the other hand, EPA could not identify one technology that represented BTA for existing facilities on a national basis.

B. Overview of Final Rule Requirements

As noted, EPA concluded that the best technology available for minimizing impingement mortality was ''modified traveling screens,'' as more specifically defined in the rule. The BTA Impingement Mortality Standard includes seven technology options for complying with the standard whose performance is equivalent to, or better performing than modified traveling screens. First, the rule identifies four technologies (closed-cycle recirculating systems, reduced design intake velocity, reduced actual intake velocity, and existing offshore velocity caps) that reduce impingement mortality as well or better than modified traveling screens, and therefore will generally comply with the BTA Impingement Mortality Standard of today's final rule.

The rule also provides that, if the Director determines that modified traveling screens are insufficient to protect shellfish, the Director may establish additional measures under § 125.94(c)(8) such as seasonal deployment of barrier nets, or if modified traveling screens [45] are insufficient to protect other species, the Director may establish additional protective measures under § 125.94(c)(9). In addition, the rule provides in § 125.94(g) that the Director may establish additional control measures and monitoring or reporting requirements in the permit in order to protect Federally-listed threatened and endangered species and designated critical habitat. The Director may include such conditions that are designed to minimize incidental take, reduce or remove more than minor detrimental effects to Federally-listed species and designated critical habitat or avoid jeopardizing Federally-listed species and or destroying or adversely modifying designated critical habitat (e.g., prey base).

Next, the final rule provides an option that allows a facility to demonstrate to its permitting authority that it has installed modified traveling screens—the technology EPA identified as the basis for the BTA impingement mortality standard—and to provide data on the performance of its screens. The facility must demonstrate that its modified traveling screens are consistent with EPA's definition and demonstrate through an impingement technology performance optimization study that its screens have been optimized to minimize impingement mortality. After consideration of the information provided, the permitting authority will determine whether the technology is the best technology available for impingement mortality reduction at the site and include permit conditions to ensure optimal performance of the screens. In other words, the owner or operator of a facility will comply with the BTA standard for IM at § 125.94(c)(5) if that facility uses modified traveling screens as defined at § 125.92(s), and operates in accordance with the permit conditions established by the Director that ensure the technology will perform as demonstrated. As noted above, in certain circumstances, under §§ 125.94(c)(8), (9) and 125.94(g), the Director may require additional protective measures.

As stated in the June 11, 2012 NODA, EPA does not intend for facilities to install closed-cycle cooling solely for the purpose of meeting the IM requirements. In fact, EPA expects all facilities could comply with IM requirements without relying on retrofitting to closed-cycle cooling (see Exhibit VIII–1, showing expected compliance alternative based on technologies in place today). If a facility chooses to comply with the BTA IM standard by installing and operating traveling screens, the screens must meet the definition of modified traveling screens provided at § 125.92(s). These may include, for example, modified Ristroph screens with a fish handling and return system, dual flow screens with smooth mesh, and rotary screens with fish returns such as vacuum pumps. EPA based the regulatory definition on the commonly found features of modified traveling screens used in developing the BTA impingement mortality standard.

In addition, the final rule also provides a compliance option that would allow facilities the option of demonstrating to the Director on a site-specific basis, similar to the showing for modified traveling screens, that a system or combination of technical and operational measures will achieve the BTA standard for impingement mortality at a particular site. Using a combination of technical and operational measures as the basis for demonstrating compliance allows facilities the opportunity to take credit for intake location, flow reduction, or other measures already employed to reduce the rate of impingement. Further, the combination of technical and operational measures provides the flexibility to use a system of approaches to reducing impingement and impingement mortality. This may include technologies that were not found to reduce impingement consistently or in all circumstances, but that on a site-specific basis have been demonstrated to provide a high level of performance. For example, a facility might employ light and sound to induce an avoidance response from certain species. This might not alone address impingement mortality for all non-fragile species at the intake, therefore additional measures (intake location, barrier nets, etc.) would also be applied, to minimize the rate of impingement or impingement mortality.

For both the screens and system of technologies, a two year study must be completed in which biological data collection is used to make site-specific adjustments to screens or the combination of technologies in order to optimize performance at that facility. Those optimal operating parameters then become permit conditions. For facilities that have already installed traveling screens or the technologies associated with the system approach, EPA has combined the two year biological study with the other permit application and rule requirements for biological data collection, including the Source Water Baseline Biological Characterization Data. In this manner, EPA is establishing a consistent set of biological study requirements, with an overall reduction in the burden of the required level of biological monitoring.

Lastly, a facility may choose to comply with the numerical impingement mortality performance standard that was established based on the BTA technology. If a facility chooses this compliance option, it must conduct periodic monitoring to demonstrate compliance. Under this last compliance option, a facility could implement innovative technologies to address impingement mortality and subsequently demonstrate that their performance is as good as, or better than, a modified traveling screen with fish handling and return system. EPA envisions that after a sufficient demonstration period of a technology's performance, the facility will be able to qualify its operation under the previous option.

For entrainment, on the other hand, EPA could not identify one technology that represented BTA for existing facilities on a national basis, for the reasons explained in detail below. Instead, the national BTA entrainment standards for existing facilities establishes a detailed regulatory framework for the determination of BTA

[45] Or any of the IM compliance alternatives.

entrainment requirements by the permitting authority on a site-specific basis.

While site-specific permit requirements are not new, what is different about this approach from the current requirement for permits to include 316(b) conditions is that for the first time, EPA is establishing a detailed specific framework for determining BTA entrainment control requirements. Thus, the rule identifies what information must be submitted in the permit application, prescribes procedures that the Director must follow in decision making and factors that must be considered in determining what entrainment controls and associated requirements are BTA on a site-specific basis.

As previously noted, EPA looked at a number of factors in considering what national entrainment standard it should adopt. As discussed in detail in the following section, EPA identified only one high performing technology as a potential BTA candidate for entrainment: closed-cycle recirculating systems as defined at § 125.92(c)(1). While there are other technologies for entrainment that are available or demonstrated, they are not uniformly high performing technologies. See TDD Chapter 6 for more information regarding the lack of intermediate performing technologies for entrainment. EPA has identified the following specific factors as the key elements in its decision not to prescribe this technology as the basis for a national BTA standard for entrainment: land availability, air emissions, and remaining useful plant life. How these factors dictated EPA's decision is discussed below.

For new units at existing facilities, EPA has established BTA requirements to minimize impingement mortality and entrainment, based on flow reduction commensurate with closed-cycle cooling. The rest of this section describes in detail the above considerations.

C. Technologies Considered To Minimize Impingement and Entrainment

As described in Chapter 4 of the TDD, power plants and manufacturers withdraw large volumes of cooling water daily. Cooling water withdrawals are responsible for over half of surface water withdrawals for all uses in the United States, including agriculture and municipal uses. The purpose of cooling water withdrawals is to dissipate that portion of the heat that is a by-product of industrial processes that facilities have not harnessed to a productive end and therefore view as waste heat.

The majority of environmental impacts associated with intake structures are caused by water withdrawals that ultimately result in the loss of aquatic organisms. These losses might be from impingement, entrainment, or both. Impingement occurs when organisms are trapped against the outer part of a screening device of an intake structure.[46] The force of the intake water traps the organisms against the screen and they are unable to escape. Not all organisms in the incoming water are impinged, however. Some might pass through the screening device and travel through the entire cooling system, including the pumps, condenser or heat exchanger tubes, and discharge pipes. This is referred to as entrainment. Various factors lead to the susceptibility of an organism to impingement or entrainment. For more detailed discussion of impingement and entrainment and the associated mortality and other effects, see Section III above.

For purposes of this rule, EPA is adopting the following conventions for defining impingement and entrainment and mortality:

- Impingement: Occurs when any life stage of fish and shellfish are pinned against the outer part of an intake structure or against a screening device during intake water withdrawal. Impingement may also occur when an organism is near a screen but unable to swim away from the intake structure because of the water velocity at the intake.
- Entrainment: Occurs when any life stages of fish and shellfish are drawn into the intake water flow entering and passing through a cooling water intake structure and into a cooling system.
- Impingement Mortality: The death of fish or shellfish due to impingement. It may also include organisms removed from their natural ecosystem and lacking the ability to escape the cooling water intake system and thus subject to mortality. Note that impingement mortality need not occur immediately. Impingement may cause harm to the organism which results in mortality at some time after impingement. For purposes of this rule, EPA has defined impingement mortality as the death of those organisms collected or retained by a sieve with a maximum opening of 0.56 inches; this includes both the 3⁄8-inch sieve and a 1⁄2-inch by 1⁄4-inch mesh.[47]
- Entrainment Mortality: The death of fish or shellfish due to entrainment. This is typically associated with mortality related to small organisms that pass the entire way through a facility and are killed as a result of thermal, physical, or chemical stresses. This term also includes the death of those fish and shellfish that may occur on fine mesh screens or other technologies used to exclude the organisms from entrainment. For purposes of this rule, EPA defined entrainment mortality as the death of those organisms passing through a sieve with a maximum opening of 0.56 inches.

Impingement mortality is typically less than 100 percent of the impinged organisms if a fish return or backwash system is employed. Impingeable organisms are generally not very small fish or early life stages (e.g., those that can pass through 3⁄8-inch mesh screens), but typically are fish with fully formed scales and skeletal structures and well-developed survival traits such as behavioral responses to avoid danger. EPA's data demonstrate that, under the proper conditions, many impinged organisms can survive.

Entrainable organisms generally consist of eggs and early life stage larvae. Early larvae generally do not have skeletal structures, have not yet developed scales, and in many cases are incapable of swimming for several days after hatching. EPA has found that entrainable organisms that are collected after interaction with the CWIS show poor survival in the case of most eggs, and essentially no survival of larvae. Consequently, on the basis of the record information it has reviewed, EPA concluded for purposes of this rule that all entrained organisms die, i.e., no entrained organisms survive. (See, for example, 76 FR 22188 [April 20, 2011] and 69 FR 41620 [July 9, 2004].) Therefore, without entrainment control, entrainment is assumed to lead to entrainment mortality. Also see Chapter A7 of the Phase II Regional Studies Document (DCN 6–0003; EPA–HQ–OW–2002–0049–1490).

Whether an organism near a cooling water intake structure is impinged or entrained is a function of the screen mesh size. Holding the number and size distribution of organisms at the intake constant, a larger screen mesh size will result in relatively more entrainment, while a smaller mesh size will result in

[46] Typically, cooling water intake structures use various screening devices to prevent objects (e.g., debris, trash) from being drawn in with the cooling water and ultimately clogging or damaging the cooling water system, especially the condenser or heat exchanger components.

[47] Mesh sizes of 3⁄8″ are commonly referred to as coarse mesh; this refers to the size of the screen opening (in contrast to fine mesh) and not the roughness of the mesh material.

relatively more impingement. Historically, traveling screens deployed by power plants used a 3⁄8-inch mesh size. For this reason, most studies and reports referring to impingement are in fact referring to those organisms impinged on a 3⁄8-inch mesh screen. Similarly, entrainable organisms are those organisms fitting through a mesh of less than or equal to 3⁄8 of an inch. This also means the majority of entrainable organisms are composed of eggs, larvae, and smaller juveniles. More recent studies, particularly those that evaluate mesh sizes smaller than 3⁄8 of an inch, continue to refer to impingement as any organism caught on the screen. This can cause some confusion because many organisms that would have been entrained with a 3⁄8-inch mesh instead become impinged by the finer mesh. These are referred to as impinged entrainables or ''converts.'' EPA has also found that most studies of entrainment are biased toward the larger (older) larvae with higher survival rates and do not analyze survival of smaller larvae. This bias implies a focus on larvae body lengths sufficient to have begun scale and bone development, and it generally reflects the more motile early life stages. EPA found that these study findings cannot be applied to smaller and less motile life stages, which are incapable of avoidance responses. It is also important to note that preventing entrainment by some exclusion technologies might result in very high entrainment reductions by converting entrainment to impingement, but these impinged organisms may have an even lower likelihood of surviving impingement than larger potentially impinged organisms. Therefore, while entrainment refers specifically to passage through the cooling water intake system, entrainment mortality also includes those smaller organisms killed by exclusion from the cooling water intake system. Today's rule uses the 3⁄8-inch mesh size as part of the definition of impingement mortality and entrainment mortality as a means of clearly differentiating those organisms that might be susceptible to impingement or entrainment, and thereby avoids any confusion over the status of impinged entrainables or ''converts.''

Generally, two basic approaches can be used to reduce impingement mortality and entrainment. The first approach is flow reduction, where the facility installs a technology or operates in a manner to reduce or eliminate the quantity of water being withdrawn. Reduced volumes of cooling water produce a corresponding reduction in impingement and entrainment and, therefore, reduced impingement mortality and entrainment mortality. It should be noted that, at electric generators, flow reduction could be achieved, perhaps most effectively, by installing more energy efficient production, thereby requiring less cooling per unit of electricity generated. The second way to reduce impingement and entrainment is to install technologies or operate in a manner that either (1) gently excludes organisms or (2) collects and returns organisms without harm. Exclusion technologies or practices divert those organisms that would have been subject to impingement and entrainment away from the intake. Collection and return technologies are installed to collect and return organisms to the source water, allowing impingement to occur but possibly preventing impingement mortality.

Although not available to all facilities, two other approaches to reducing impingement and entrainment are (1) relocating the facility's intake to a less biologically rich area in a waterbody, and (2) reducing the intake velocity. Relocating an intake farther from shore or at greater depths can be effective at entrainment reduction but is not available to many inland facilities because the distance or depths required to reach less biologically-productive waters are not generally available. Further, while a far offshore intake may exhibit a lower density of organisms, the species found will change as a function of distance from the shoreline as well as depth in the water column. Therefore, it may not always be desirable to relocate an intake structure. A reduced intake velocity provides motile organisms the opportunity to swim away from the intake structure. This approach can be very effective in reducing impingement but has no effect on entrainment.

Sections 1 and 2 below further describes flow-reduction and exclusion technologies.

1. Flow Reduction

Flow reduction is commonly used to reduce impingement and entrainment. For purposes of this rulemaking, EPA assumes that entrainment and impingement (and associated mortality) at a site are proportional to source water intake volume. Thus, if a facility reduces its intake flow, it similarly reduces the amount of organisms subject to impingement and entrainment.[48] Some common flow reduction technologies are variable frequency drives and variable speed pumps, seasonal operation or seasonal flow reductions, unit retirements, use of alternate cooling water sources, water reuse, and closed-cycle cooling systems. For additional detailed information on these technologies as well as others, see Chapter 6 of the TDD, ''California's Coastal Power Plants: Alternative Cooling System Analysis'' (DCN 10–6964), and EPRI's ''Fish Protection at Cooling Water Intake Structures: A Technical Reference Manual'' (DCN 10–6813).

a. Variable Frequency Drives and Variable Speed Pumps

A facility with variable speed drives or pumps operating at their design maximum can withdraw the same volume of water as a conventional circulating water pump. However, unlike a conventional circulating water pump, variable speed drives and pumps allow a facility to reduce the volume of water being withdrawn for certain periods. The pump speed can be adjusted to reduce water withdrawals when cooling water needs are reduced, such as when ambient water temperatures are colder (and therefore capable of dissipating more heat), when fewer generating units are operating or when fuel is more efficiently burned. In site visits, EPA found that variable drives and pumps were typically used at units operating below capacity, such as load-following units. EPA estimates that facilities with intermittent water withdrawals could achieve a 5 to 10 percent reduction in flow.[49] For this reason, many baseload generating units and continuously operated manufacturing processes will obtain limited reductions in flow from using these technologies. EPA is further aware that some facilities may need to

[48] Impingement rates are related to intake flow, intake velocity, and the swimming ability of the fish subject to impingement. Entrainment is generally considered to be proportional to flow and therefore a reduction in flow results in a proportional reduction in entrainment, as EPA assumes for purposes of national rulemaking that entrainable organisms are uniformly distributed throughout the source water. EPA has consistently applied this assumption throughout the 316(b) rulemaking process (for a discussion of proportional flow requirements in the Phase I and II rules see, e.g., 66 FR 65276 and 69 FR 41599; also see EPA's 1977 draft guidance manual for 316(b), available at DCN 1–5045–PR from the Phase I docket) and continues to assume that it is broadly applicable on a national scale and is an appropriate assumption for a national rulemaking. EPA recognizes that this assumption does not necessarily apply when relocating or varying the time pattern of withdrawals, such that these may be effective strategies to reduce impingement and entrainment in some locations.

[49] Withdrawals of colder water could allow facilities to reduce their intake flow using variable drives and pumps, but EPA does not have data on the efficacy or availability of this approach.

withdraw water for cooling even while the facility is not in production, such as facilities on standby status, or nuclear facilities where the heat energy generated by fission must still be dissipated while the facility is out of service. As a result, EPA determined that variable frequency drives and variable speed pumps, while useful in specific setting and circumstances, are not BTA candidates because the flow reduction technologies have limited application and availability, and are not a high performing technology as an entrainment control measure.

b. Seasonal Operation or Seasonal Flow Reductions

Seasonal operation or seasonal flow reduction refers to the reduction or elimination of a quantity of water withdrawn either during periods of low demand for electricity output, or to coincide with certain biologically important periods. Most facilities that currently employ seasonal flow reductions do so to limit thermal impacts or to reduce entrainment, because entrainment often has a peak season, particularly during a local spawning season. Freshwater drum, for example, perform broadcast spawning during early summer when water temperatures reach about 65 degrees Fahrenheit.

During specific peak entrainment periods, a facility could scale back its operation (or perhaps not operate at all), thereby reducing or eliminating the volume of cooling water withdrawn. This could be accomplished through a combination of variable speed pumps or shutting down some portion of the pumping system. Seasonal flow reduction could also consist of operating a closed-cycle recirculating system as defined at § 125.92(c)(1) as once-through during part of the year and as a closed-cycle system during the peak entrainment season. (EPA notes that closed-cycle cooling has been rejected as noted in the previous section, and discussed in more detail below.) Facilities could also choose to schedule regular maintenance to occur during these high entrainment periods. These maintenance activities often require the facility to reduce or cease operations and can be timed to coincide with the most biologically productive periods. Through site visits, EPA gathered information on species present at facilities and has identified some sites where entrainment appears to be significant all year long, and other sites where peak entrainment occurs in as few as three to four months of the year.[50] However, if all power-generating facilities in a local area were to stop operating at the same time, there could be difficulty in supplying electricity to the area. Therefore, EPA concluded that seasonal operations have limited nationwide application for controlling entrainment and are thus not widely available entrainment reduction technology.

Impingement is generally more sporadic, less predictable, and more difficult to address with seasonal operation. For example, clupeid species, such as gizzard shad, experience impingement episodes sporadically throughout the winter and spring during periods of especially cold water temperatures, or sporadically throughout the summer and fall during periods of low dissolved oxygen.

c. Unit Retirements

Some power plants units have been retired and others have essentially ceased all operations but have not been formally retired or decommissioned. The reasons for their inactivity vary,[51] but the end result is the facility no longer needs cooling water withdrawals for these units. Similarly, manufacturers may retire processing units as market demand changes, process lines are moved to other sites, or production technologies change. Unit closures provide clear reductions in flow, but the demand for electricity (or other products) might dictate that production be increased at the facility in question or at another facility altogether; there is usually no guarantee that the intake flow will be permanently retired. EPA expects flow reductions due to unit closures could be reasonably included as part of a facility's impingement mortality and entrainment reductions strategy. Given the number of variables involved in the decision to retire a unit and the likelihood of a facility having a unit that is ready to retire at promulgation of the final rule, unit retirements are not a nationally available entrainment reduction measure. See Section VIII for further discussion of how a facility can take credit for flow reductions attributable to unit closures.

d. Use of Alternate Cooling Water Sources

While not reducing the overall usage of water at a facility, using an alternate source of cooling water can reduce impingement and entrainment if the alternate source substitutes for withdrawals from surface waters. An example is using ''gray'' water as a source of cooling water, such as a facility that reaches an agreement with a nearby wastewater treatment plant to accept the wastewater treatment plant's effluent as a source of cooling water.[52] Such alternate sources are limited by available capacity and consistency of flow. Increasing competition for these sources of water may make this a more challenging approach for existing facilities than for new facilities that are not yet fixed in location. In principle, alternate sources could be used to fulfill either a fraction or all of a facility's cooling water demands. In practice, the location of alternate sources, the costs of moving water from the alternate source to the facility, and whether the facility uses a once-through or closed-cycle recirculating system as defined at § 125.92(c) will determine whether the alternate source can meet all or a portion of the facility's cooling water needs. All these factors limit the widespread availability of alternate cooling water sources as an entrainment reduction measure, however use of alternative sources of cooling water such as wastewater treatment effluent could be attractive for certain facilities where the cost of retrofitting or other site-specific circumstances are favorable.[53]

e. Water Reuse

Typically associated with manufacturing facilities, water reuse (defined as using water for multiple processes) can reduce the volume of water needed for cooling, process, or other uses. For example, a facility might withdraw water for non-contact cooling water and then reuse the heated effluent as part of an industrial process. In effect, the facility has eliminated the need to withdraw additional water for the latter

[50] See DCN 10–6702 and its attachments for examples of spawning ''seasons.''

[51] Note that some generating units are retired by the owner (*i.e.,* the unit is no longer considered sufficiently profitable to operate) or is rarely dispatched by its independent system operator for market-driven reasons (*i.e.,* the unit cannot deliver at a competitive price except during limited peak seasons; see also § 125.94(c)(12)). They may also be mothballed, placed on cold storage, or maintained in various other states of operational readiness.

[52] See, for example, EPA's site visit report for PSEG's Linden Generating Station (DCN 10–6557), which has a capacity of 1230 MW, 35 percent CUR, and uses 7–8 mgd of gray water as the sole source of makeup water for its cooling towers.

[53] For maps showing which electric generators are near a source of available reuse water for cooling, see Tidwell, V., J. Macknick, K. Zemlick, J. Sanchez, and T. Woldeyesus. 2013. ''Transitioning to Zero Freshwater Withdrawal for Thermoelectric Generation in the United States.'' (submitted). See also the accompanying presentation given at the American Geophysical Union Fall 2012 Meeting available at *http://www.nrel.gov/docs/fy13osti/57444.pdf.*

process. EPA has observed significant water reuse at manufacturing facilities but has not developed national level data for such reuse because of the range of different manufacturing sectors and the significant variability in manufacturing processes appropriate for reuse. For example, during site visits, EPA observed that it may be difficult to quantify specific water reuse at complex facilities. (See, for example, the site visit report for ArcelorMittal, a steel mill at DCN 10–6551.) For additional detail on water usage in specific industrial sectors, see Chapters 4 and 8 of the TDD.

Increasingly, electric utilities are adopting water reuse to meet a portion or all of their cooling water demands. Water reuse can enhance the reliability of power generation in water-limited environments. Given the complex use (and reuse) patterns for some facilities and the lack of reuse at other facilities, water reuse cannot be considered as a widely available entrainment reduction option.

f. Closed-Cycle Cooling Systems

Closed-cycle cooling systems allow a facility to transfer its waste heat to the environment using significantly smaller quantities of water relative to once-through cooling, and in some cases no water. The main types of closed-cycle cooling systems are wet cooling, dry cooling, hybrid cooling, and impoundments. Each is described below.

i. Wet Cooling Systems

In a wet cooling system, cooling water that has absorbed waste heat transfers that heat through evaporation of some of the heated water into the surrounding air and recirculates the now cooled water to continue the cooling process.[54] This process enables a facility to reuse the remaining water, thereby reducing the quantity of water that must be withdrawn from a waterbody. Because the heat is transferred through evaporation, the amount of water withdrawn from the water source is greatly reduced, though not eliminated completely, because make-up water is required to replace that lost through evaporation and blowdown.[55] The two main types of wet cooling systems are natural draft and mechanical. While wet cooling systems reduce withdrawals significantly relative to once-through systems, they can increase the consumptive use of water because they rely on evaporation (which is not returned to the waterbody) for heat dissipation. When once-through cooling is used and withdrawals are a significant portion of the source waterbody, the return of heated water might contribute to greater evaporation from the waterbody relative to the waterbody's normal evaporation rate. EPA does not have conclusive data on the relative magnitude of these effects, but the data do suggest that the relative difference in evaporation is not so great that it will play a major role in determining a cooling system type in most watersheds. EPA examined available information on evaporation losses in DCN 12–6673, including a comparison to evaporative losses from the downstream effluent plume of once-through cooling systems. While EPA recognizes that evaporative losses from closed-cycle systems are greater, EPA's analysis does not suggest that the difference is substantial enough to outweigh the significant reduction in adverse environmental impacts to aquatic organisms. However, the relative loss of water through evaporation for closed-cycle and once-through systems is site-specific, depending on the exact design of the systems.

There are two common designs for wet cooling systems. A natural draft cooling tower can be as tall as 500 feet and has a hyperbolic shape. The height of these towers creates a temperature differential between the top and bottom of the tower, which creates a natural chimney effect that transfers heat as heated water contacts rising air. In contrast, mechanical cooling towers rely on motorized fans to draw air through the tower and into contact with the heated water.[56] These towers are much shorter than natural draft cooling towers (typically 30 to 75 feet tall) and can be built in groups. Mechanical cooling towers may require more land area than natural draft cooling towers for an equivalent amount of cooling. Both types of towers require electricity for pumps, but mechanical draft towers also require electricity to operate the fans. In both cases, the electricity need of the towers reduces an electric generating facility's net generating output. Thus, the monetary and environmental costs of this reduction in energy efficiency must be considered. These environmental costs include human health and welfare effects from increased air emissions (from burning additional fuel to make up for the power that cannot be sold) and the global climate change effects of increased greenhouse gas output at fossil-fueled facilities (these costs are now explicitly considered in the benefit-cost analysis; see Section X below). Both natural draft and mechanical cooling towers can operate in freshwater or saltwater environments. Saltwater applications typically require more make-up water than freshwater applications, making them less efficient in reducing water withdrawals. Optimized cooling towers can achieve flow reductions of 97.5 and 94.9 percent or better for freshwater and saltwater sources, respectively.

ii. Dry Cooling Systems

Dry cooling systems virtually eliminate the need for cooling water withdrawals.[57] Unlike wet cooling systems, waste heat in dry cooling systems is transferred completely through convection and radiation, rather than evaporation. Direct dry cooling is much like a car radiator; turbine exhaust steam passes through tubes or fins for cooling, and the condensate is returned to the boiler to be reheated into steam to propel the turbine. The system is completely closed to the atmosphere, and there is no contact between the outside air and the steam or the resulting condensate. Because of the heavy reliance of dry cooling on ambient air temperatures and the lower efficiency of heat transfer through convection and radiation, dry cooling systems are much larger and therefore more expensive[58] than wet cooling systems for a given cooling load. While dry cooling systems are not uncommon in the U.S. (see DCN 10–6943), they have typically been built at smaller generating units or in areas where limited water supplies might make

[54] In addition, a smaller portion of the heat is also removed through direct contact between the warm water and the cooler surroundings; this is known as sensible heat.

[55] Cooling towers must replace water lost to evaporation; this is referred to as makeup water. Additionally, as water evaporates, dissolved solids and other materials gradually increase in concentration in the circulating water and can cause operational difficulties. To minimize these issues, cooling tower operators continually discharge a small portion of the circulating flow and replace it with makeup water; this is referred to as blowdown.

[56] Modular cooling tower units provide an additional cooling tower alternative. Modular cooling towers resemble mechanical cooling towers, but are portable, typically rented for short-term periods and quickly assembled.

[57] Dry cooling systems blow down some of the circulating water in the cooling system to prevent the buildup of materials in the condenser. However, the volume of makeup water is extremely low—a dry cooling system typically reduces intake flows by 98–99 percent over a comparable once-through cooling system.

[58] The construction and capital costs for dry cooling towers have been reported as four to 10 times more expensive as wet cooling towers, and the auxiliary power consumption for dry cooling is higher than for wet cooling. See DCN 10–6679. EPA recognizes that costs for dry cooling may have decreased since this document was written, but costs for dry cooling are still markedly higher than those for wet cooling. The other challenges associated with dry cooling remain unchanged.

uncertain the availability of either once-through cooling or wet cooling make-up water, such as the arid southwestern United States. Dry cooling has not been used for circulating water cooling at nuclear facilities.

iii. Hybrid Cooling Systems

In certain applications, a facility could choose a hybrid cooling system design that incorporates elements of both wet and dry cooling. Typically, the base of the tower functions as a wet cooling system and the upper portion as a dry cooling system. The most common reason for this design is to reduce the visible plume of water vapor, which is accomplished by recapturing some of the water vapor evaporated in the wet portion of the tower. This design is also usually much shorter than natural draft wet towers and can also include plume abatement controls. Another version of the hybrid cooling system also includes both wet and dry cooling sections, but the dry section functions to directly cool a portion of the turbine exhaust steam. The benefits of such a tower may include substantial water savings as well as reduction in power plant efficiency losses associated with just dry cooling.

iv. Impoundments

Impoundments are surface waterbodies that serve as both a source of cooling water and a heat sink. As with cooling towers, impoundments rely on evaporative cooling to dissipate the waste heat; a facility withdraws water from one part of the impoundment and then discharges the heated effluent back to the impoundment, usually in another location to allow the heated water time to cool. Depending on local hydrology, impoundments may also require makeup water from another waterbody. Impoundments can be man-made or natural, and can be offset from other water bodies or as part of a ''run of the river'' system (the latter are sometimes referred to as cooling lakes).

2. Exclusion and Collection Technologies

Over the last several decades, numerous technologies in addition to specific flow reduction measures such as velocity controls and closed-cycle cooling have been developed in an effort to minimize impingement mortality and entrainment associated with cooling water intake systems. The following section summarizes the most widely used technologies and the most effective and best-performing technologies, such as screens, barrier nets, aquatic filter barriers, and collection and return systems. For additional detailed information on these technologies and others, also see Chapter 6 of the TDD, ''California's Coastal Power Plants'' report (DCN 10–6964) or EPRI's ''Fish Protection at Cooling Water Intake Structures'' report (DCN 10–6813).

a. Screens

There are several types of screens that offer protection that are discussed below, including traveling screens and cylindrical wedgewire screens. Not described in this section are fixed screens that are used simply for the purpose of debris exclusion but do not offer protection to fish, larvae, and eggs.

i. Traveling Screens

Traveling screens are a technology in place as part of most cooling water intake structures. These screens originally were designed to prevent debris from entering the cooling water system, but they also prevent some fish and shellfish from entering the cooling water system. Traveling screens have been installed in a wide variety of operating and environmental conditions: salt water, brackish water, freshwater, and icy water, as well as river, lake and tidal applications. On the basis of the technical survey, EPA found 93 percent of electric generators and 73 percent of manufacturers employ traveling water screens or other intake screens. Many types of traveling water screens (e.g., through flow, dual flow, center flow) are used. The most common design in the United States is the through flow system. The screens are installed behind bar racks (trash racks) but in front of the water circulation pumps. The screens rotate up and, while out of the water, debris and impinged organisms are removed from the screen surface by a high-pressure spray wash. Screen wash cycles are triggered either manually or by a certain level of head loss across the screen (indicating clogging). By definition, this technology works by collecting (i.e., impinging) fish and shellfish on the screen. Ideally, traveling screens would be used with a fish handling and return system, as discussed below. The return system should be regularly maintained to prevent biofouling or other blockages that may affect survival.

ii. Cylindrical Wedgewire Screens

Unlike traveling screens, cylindrical wedgewire screens are a passive intake system. Wedgewire screens, also called ''V'' screens or profile screens, consist of triangular-shaped wires arrayed on a cylindrical framing system, with long slots between the wires, lengthwise along the screen. Slot sizes for conventional traveling screens typically refer to a square opening (3⁄8 inch by 3⁄8 inch) that is punched, molded, or woven into the screen face. Wedgewire screens are constructed differently, however, with the slot size referring to the distance between longitudinally adjacent wires. These screens are designed to have a low through-slot velocity (less than 0.5 fps or 0.15 meter per second) and typically have smaller slot sizes than a coarse mesh traveling screen. The entire wedgewire structure is submerged in the source waterbody. (See Chapter 6 of the TDD for an illustration of these screens.)

When necessary conditions regarding placement in the waterbody are met, these screens exploit physical and hydraulic exclusion mechanisms to achieve consistently high impingement reductions, and as a result, impingement mortality reductions. Wedgewire screens require an ambient crossflow current to maximize the sweeping velocity provided by the waterbody. The screen orientation allows the crossflow to carry organisms away from the screen allowing them to avoid or escape the intake. Lower intake velocities also allow fish to escape from the screen face. Entrainment reductions can also be observed when the screen slot size is small enough and intake velocity is low enough to exclude egg and larval life stages.[59] Limited evidence also suggests that extremely low intake velocities can allow some egg and larval life stages to avoid the intake because of hydrodynamic influences of the crossflow. Therefore, performance is dictated largely by local conditions that are further dependent on the source waterbody's biological composition. Costs of wedgewire screens increase significantly as slot size and design intake velocity decrease because the cumulative size of the screen (or number of screens) must grow in order to accommodate the same flow of cooling water. Wedgewire screens can also employ cleaning and deicing systems such as air-burst sparging to help maintain open intake structures and low intake velocities.

According to data from the industry questionnaire, EPA's site visits, and industry documents, dozens of facilities across the United States employ cylindrical wedgewire screens. However, wedgewire screens are not feasible for all facilities, particularly where intakes are in shallow water or have limited shoreline frontage. Also,

[59] Note that this is entrainment exclusion and not necessarily related to the survival of entrainable organisms.

wedgewire screens might not be feasible where the size and number of wedgewire screens would interfere with navigation of vessels. As described above, locations also need to have an adequate source water sweeping velocity. Most of the performance data for wedgewire screens is based on coarse mesh slot sizes with an intake velocity of 0.5 fps. Because it is extremely difficult to measure impingement and entrainment reductions in the field, most performance data for wedgewire screens is based on barge and lab studies.[60] EPA does not have data on the performance of fine mesh wedgewire screens on entrainment survival. Consequently, EPA has considered wedgewire screens only for impingement mortality. For additional discussion of the specific design and operation of cylindrical wedgewire screens, see Chapter 6 of the TDD. The following section discusses the importance of mesh size to impingement mortality and entrainment reductions.

iii. Screen Mesh Size Considerations

Coarse Mesh

Coarse mesh traveling screens are the typical traveling screen fitted on the majority of cooling water intakes. A large number of facilities have intake screens with 3⁄8-inch (9.5 mm) mesh panels.[61] This size mesh is common because, as a general rule, the maximum screen slot size is never larger than one-half of the condenser tube diameter (the condenser tubing is the narrowest point in the cooling water system and, as such, is most susceptible to clogging from debris), and this tubing is typically 3⁄4 or 7⁄8 inch in diameter. Mesh of 3⁄8-inch (roughly 9.5 mm) size does not prevent entrainment and without any other precautions can lead to high mortality of impinged fish. Coarse mesh traveling screens have been in use by both power plants and manufacturers for more than 75 years and represent the baseline technology. Similarly, the majority of successful wedgewire installations are coarse mesh.

Fine Mesh

Fine mesh traveling and wedgewire screens are similar to coarse mesh screens. The only difference is the size of the screen mesh. Fine mesh traveling screens have been in use since the 1980s. Typically, facilities have incorporated fine mesh in an effort to reduce entrainment. The mesh size varies, depending on the organisms to be protected, but typically range from 0.5 to 5 mm. Data in the record demonstrate that entrainment typically decreases as mesh size decreases. Slot sizes larger than 2 mm do not prevent eggs from passing through the screen. Converting traveling screens from coarse mesh to fine mesh often requires adding more screens in order to maintain the same flow, since the open area of a fine mesh screen is less than the open area of a coarse mesh screen. Adding more screens is one way to maintain that flow.[62] EPA estimates that as many as 17 percent of existing intakes could not be enlarged to accommodate a 2 mm mesh, and as many as 55 percent of existing intakes could not accommodate a 0.5 mm slot size under conditions of low-intake velocities. For these reasons, fine mesh screens are available for some locations, but they are not the best performing technology and are not an available technology for the industry as a whole for IM&E. For more details, see Chapter 6 of the TDD.

b. Barrier Nets

Barrier nets are nets that fully encircle the intake area of water withdrawal, from the bottom of the water column to the surface, and prevent fish and shellfish from coming in contact with the intake structure and screens. According to data from the industry questionnaire (as of the year 2000), at least a half dozen facilities employ a barrier net. Typically, barrier nets have large mesh sizes (e.g., 1⁄2-inch or 12.7 mm)[63] and are designed to prevent impingement. Because of the large mesh size, they offer no reduction in entrainment. They are often deployed seasonally, wherever seasonal migrations create high impingement events or to avoid harsh winter conditions that jeopardize integrity of the net. Barrier nets also prevent impingement of shellfish on the intake traveling screen. Shellfish such as crustaceans can pose a unique issue for traveling screens; shellfish are not impinged, but they can attach to the traveling screen surface and are not removed from the traveling screen by pressure wash sprays. Barrier nets have been shown to be helpful in this regard.

c. Aquatic Filter Barriers

Aquatic Filter Barriers (AFBs) consist of water-permeable fabric panels with small pores (less than 20 microns). They are similar to barrier nets in that they extend throughout the area of water withdrawal from the bottom of the water column to the surface. AFBs reduce both impingement mortality and entrainment because they present a physical barrier to all life stages. The surface area of an AFB is quite large compared to a traveling screen, allowing for extremely low water velocities. The low velocity allows non-motile organisms to drift away. EPA is aware of one power plant that used an AFB but notes that this facility recently ceased operations.[64] EPA has updated performance data for AFB for small flow intakes, but it does not have enough data to evaluate the technology at large intakes or in all water bodies. EPA does not consider this technology to be demonstrated and available as a nationwide BTA candidate.

d. Collection and Return Systems

Conventional traveling screens were not designed initially with the intention of protecting fish and aquatic organisms that become impinged against them. The organisms were often handled in the same manner as debris on the screens. Marine life can become impinged against the screens because of high intake velocities that prevent their escape. Prolonged contact with the screens can suffocate organisms that are unable to escape or result in descaling injury and latent mortality. Organisms that survive initial impingement and removal are not always provided with a specifically designed mechanism to return them to the waterbody and are often handled in the same way as other screening debris. Other objects, such as leaves and trash, that are collected on the screen are typically removed with a high-pressure spray and deposited in a dumpster or debris return trough for disposal. Exposure to high pressure sprays and other screening debris can cause significant injuries that result in latent mortality or increase the susceptibility to predation or re-impingement. Screens are rotated periodically on a set time interval or when the pressure differential between the upstream and downstream faces exceeds a set value.

Conventional traveling screen systems have been modified to reduce impingement-related mortalities with

[60] EPA expects that properly designed wedgewire screens have a design intake velocity of 0.5 fps, therefore intakes with wedgewire screens will meet the impingement standard at § 125.94(c)(2) and there is no need to separately pre-approve this technology as in the remanded 2004 Phase II rule.

[61] In today's rule the EPA recognizes that 1⁄2- by 1⁄4-inch mesh is used in some instances and perform comparably to the 3⁄8-inch square mesh.

[62] A facility could also increase its intake velocity.

[63] Barrier net mesh sizes vary, depending on the configuration, level of debris loading, species to be protected, and other factors.

[64] This facility ceased operations for reasons unrelated to any requirements or measures addressing cooling water intake impingement or entrainment.

collection and return systems. In its simplest form, these systems are composed of a return flume or trough with sufficient water volume and flow to enable impinged organisms to return to the source water. Return systems should be designed to avoid predation and latent mortality while organisms are in the flume, maintain an appropriate water depth in the flume for high survival of the organisms, located at an appropriate elevation to avoid large drops of the organisms back to the surface water (or large hydraulic jumps if the end of the return is below the water's surface), and sited to avoid repeated impingement of the organisms by the intake structure.

Some facilities have modified conventional coarse mesh traveling screen systems to reduce impingement mortality. They did this by removing fish trapped against the screen and returning them to the receiving water with as few injuries as possible. The first modified screens, also known as Ristroph screens, feature capture and release modifications. In the simplest sense, these screens are fitted with troughs (also referred to as buckets) containing water that catch the organisms as the screen rises out of the water and the organisms are sprayed off of the screen. The return component consists of a mechanism to remove impinged fish gently from the collection buckets, such as a low-pressure spray. The buckets empty into a collection trough that returns fish to a suitable area in the source waterbody. These modified screens have shown significant reductions in impingement mortality compared with unmodified screen systems.

Data from early applications of the Ristroph screen design showed that while initial survival rates might be high at some installations, latent mortality rates were higher than anticipated. This indicated that organisms could sustain significant injuries during the impingement and return process that were not immediately fatal. According to a study conducted by Ian Fletcher in the 1990s (see DCN 5–4387), industry identified several additional critical screen modifications to address latent mortality. These included redesigning the collection buckets to minimize turbulence, adding a fish guard rail/barrier to prevent fish from escaping the collection bucket, replacing screen panel materials with ''fish-friendly,'' smooth woven mesh, and using a low-pressure wash to remove fish before any high-pressure spray to remove debris. The Fletcher analysis also identified longer impingement duration, insufficient water retention in the buckets, and exposure to the air and temperature extremes as conditions that could negatively affect fish survival. Finally, these findings indicate that modified Ristroph screens must be rotated continually instead of the periodic rotation schedule common with conventional screen systems. Performance data for modified traveling screens with fish-friendly fish return systems, sometimes referred to as post-Fletcher modifications, show low levels of impingement mortality across a wide variety of waterbody types and fish species. Additionally, recently developed screen designs (such as the Passavant Geiger, Beaudrey WIP, and Hydrolox screens) have also shown promise in reducing impingement mortality.

For additional and more detailed discussion of the specific design and operation of these screen modifications, see Chapter 6 of the TDD.

3. Other Technological Approaches

a. Intake Location and Velocity Caps

The most common intake location for a cooling water intake structure is along a shoreline. In some water bodies, however, shoreline locations are thought to have a potential for greater environmental impact because the water is withdrawn from the most biologically productive waters, especially those containing a high density of organisms in earlier life stages, such as nursery areas. Some facilities employ an offshore intake to withdraw water from less biologically productive areas to reduce impingement and entrainment relative to intakes in more productive shoreline areas. Reduction in impingement mortality and entrainment due to intake location is highly site-specific. The greatest potential for reductions is found with far offshore locations at distances of several hundred feet, not found on many rivers and streams. Both depth and the offshore location must be evaluated to determine whether fish densities and species distribution there are substantially different than those near the shoreline. Two areas where far offshore locations are commonly used today are the oceans and Great Lakes.

EPA found that several offshore intakes are fitted with a velocity cap.[65] Velocity caps are a physical structure rising vertically from the sea bottom and are placed over the top of an intake pipe. Intake water is withdrawn through openings in the velocity cap so that it converts the direction of water flow into the pipe from vertical to horizontal. The velocity cap does not act to reduce the velocity,[66] but the horizontal flow provides a physiological trigger in fish, which induces an avoidance response to reduce impingement mortality. The velocity cap further serves to limit the zone of influence of the intake to the depth level at which the velocity cap is situated, thus affecting only the life stages that live at that depth. Velocity caps are also usually equipped with supports and bar spacing selected to prevent larger aquatic organisms (e.g., sea turtles or marine mammals) from entering the intake pipe. Because velocity caps operate under the principle that the organisms can escape the current, they do not offer entrainment reductions over and above those achieved by being located offshore. Reductions in entrainment observed with velocity caps occur because of the difference in organism densities in far offshore deep water compared to a surface intake at the shoreline.

Far offshore velocity caps have limited application in oceans and the Great Lakes, are not available in other water bodies, and are therefore not available as a candidate for a national BTA. However, the technology is a demonstrated high performing technology, and is therefore included as a compliance alternative for those facilities where the technology is available. For additional and more detailed discussion of the specific design and operation of offshore intake locations and velocity caps, see Chapter 6 of the TDD.

b. Reduced Intake Velocity

Impingement mortality can be reduced greatly by reducing the through-screen velocity in any screen.[67] Reducing the rate of flow of cooling water through the screen (through-screen velocity) to 0.5 fps or less reduces impingement of most fish because it allows them to escape the intake current. (See 66 FR 65274 [December 18, 2001] and DCN 2–028A, EPRI's ''Technical Evaluation of the Utility of Intake Approach Velocity as an Indicator of Potential Adverse

[65] Others can be fitted with a cylindrical wedgewire screen, or might simply be an open pipe.

[66] EPA's data show that velocity caps operate at velocities above and below the 0.5 fps and can be effective using either design.

[67] Limited lab studies indicate that entrainment also can decrease as through-screen velocity decreases and that through-screen velocity can have an effect on entrainment survival rates, although such data is extremely variable by species (see DCN 10–6802 and DCN 10–6803). In any case, EPA does not consider a reduced intake velocity as an effective technology for reducing entrainment, because entrainable organisms generally lack motility.

Environmental Impact Under Clean Water Act 316(b).'') As a result, some facilities have designed and operate their modified traveling screens or wedgewire screens so as not to exceed a through-screen velocity of 0.5 fps. Swim speed studies demonstrate that for most facilities, an intake velocity of 0.5 fps or less will result in 96 percent or better reductions in impingement mortality for most species. EPA notes that preliminary results from recent studies of fine mesh screens suggest that at even lower intake velocities such as 0.25 fps, some hydrodynamic influences may reduce entrainment mortality even more, because flow dynamics are nonlinear. It is unclear as to whether such observations hold true when cooling water withdrawals (water volumes) are large. While higher intake velocities are sufficiently protective for some species of fish, the higher intake velocities are not necessarily protective of all life-stages. For example, younger fish may not be strong swimmers or may have not a developed avoidance response. Therefore higher intake velocities are not a high performing technology. As noted previously, low intake velocity has limited application, and is therefore not available as a candidate BTA technology. However, the technology is a demonstrated high performing technology, and is therefore included as a compliance alternative for those facilities where the technology is available.

D. Technology Basis for Today's Final Rule

As described above, EPA examined the full range of technologies that reduce impingement or entrainment or both. From an assessment of all factors, EPA identified one technology that is best technology available for minimizing the adverse impacts of impingement mortality at existing facilities: modified traveling screens with a fish-friendly fish return. EPA identified no single best technology that is available for minimizing entrainment at existing facilities for today's final rule. For new units at existing facilities, EPA identified mechanical draft wet cooling systems as BTA for both impingement and entrainment.[68]

EPA did not identify any single technology or group of technology controls as the basis for establishing the national BTA standard for entrainment for existing units. Instead, EPA has established a national BTA standard for entrainment for existing units that requires determination of BTA entrainment requirements on a site-specific basis in a structured permitting setting. The framework for determining entrainment requirements provides for the consideration at a minimum of certain specified factors that must be considered in the Director's determination of the BTA controls.

1. Alternative Impingement Mortality Standards for Existing Units

After considering all factors identified above, EPA has concluded that modified traveling screens, such as modified Ristroph screens and equivalent modified traveling screens with fish-friendly fish returns, are a best technology available for minimizing impingement mortality.[69] These screens use 3⁄8 inch, or similar, mesh with collection buckets designed to minimize turbulence, a fish guard rail/barrier to prevent fish from escaping the collection bucket; ''fish-friendly,'' smooth, woven or synthetic mesh; and a low-pressure wash to remove fish before any high-pressure spray to remove debris. The fish removal spray must be of lower pressure, and the fish return must be fish friendly, provide sufficient water and minimize turbulence. Modified traveling screens generally must be rotated continually to minimize aquatic exposure to impingement or to the air and thus obtain the highest reductions in impingement mortality.

Under the seventh option for complying with the BTA impingement mortality standard in today's final rule, a facility may rely on any technology it chooses so long as it demonstrates through biological compliance monitoring that it achieves the required 12 month impingement mortality performance standard[70] that EPA calculated based on the performance of the BTA technology—modified traveling screens with fish return. As discussed in the TDD (see, for example, TDD Exhibits 11–1 and 11–3), EPA based the 12 month percent mortality performance at § 125.94(c)(7) on data from facilities with traveling screens modified with features to improve the post-impingement survival of organisms such as smooth mesh, continuous or near-continuous rotation of the screens, buckets with guard rails, low pressure sprays for collecting fish, and fish return systems. The statistical basis for the 12 month impingement mortality performance standard includes 26 sets of 12 month survival percentages across 17 facilities demonstrating average impingement mortality rates ranging from 1.6 to 48.8 percent under conditions of 18 to 96 hour holding times. EPA established the 12 month percent mortality as 24 percent which is the arithmetic average of the impingement mortality rates from the 17 facilities. (This is consistent with EPA's proposed rule use of expected value of the beta distribution which can be calculated as the arithmetic average.) **Note:** The 12 month impingement mortality performance standard means that no more than 24 percent of the impinged fish may die or alternatively at least 76 percent of the impinged fish must survive. EPA has occasionally used average annual limitations in the effluent guidelines program, most recently for the pulp and paper industry category (40 CFR 430, promulgated in 1998). In these instances, such as the technology-based BAT, EPA has defined the annual average limitations to be the average level demonstrated by the technology. Thus, EPA's approach to calculating the 12 month percent survival performance standard is consistent with past practice.

EPA recognizes that variability in the technology performance occurs due to changes in seasons, differing intake locations, higher mortality of certain species, and speciation found in different water bodies. By using a full 12 months of data, EPA has ensured that the resulting performance standard reflects the widest range of potential conditions present in EPA's database. EPA has further incorporated variability into the 12 month impingement mortality performance standard by basing it on data from 17 facilities which collectively performed more than 1,500 sampling events beginning as early as 1977. EPA notes that seven facilities had mortality rates less than 10 percent which provides evidence that facilities can, and have, maintained and operated their systems in a manner consistent with the performance standard. Another four facilities demonstrated impingement mortality rates significantly greater than the performance standard of 24 percent, however, EPA notes these facilities were

[68] Although EPA also identified velocity reduction to 0.5 feet per second or less as a candidate best performing technology for impingement mortality, EPA did not promulgate requirements to reduce intake velocity as BTA because it is not available at all facilities; however, the final rule does allow facilities to comply with intake velocity of 0.5 feet per second or less where available.

[69] EPA also considered recent screen designs (such as the Passavant Geiger, Beaudrey WIP, and Hydrolox screens) in evaluating impingement mortality data. In fact, the data set used to calculate the impingement mortality performance standard at § 125.94(c)(7) included a study of performance at a facility employing a Passavant Geiger screen, as well as a facility employing a Beaudrey WIP screen.

[70] In the record, EPA may also refer to this as the 12-month percent survival performance standard, % SPS, or the IM performance standard.

not required to optimize their technology performance as part of their study, and data collection was not required to achieve a certain level of performance.[71] In each study, EPA has identified elements of the technology operation that a facility could modify to achieve the 12 month percent impingement mortality performance standard. By using the 12 month percent impingement mortality performance standard, EPA has ensured that the resulting performance standard reflects the widest range of potential conditions present in EPA's database. In addition to those studies meeting the criteria for use in the 12 month percent survival performance standard calculations, there are further studies in EPA's record that provide additional performance data showing facilities can, and have, maintained and operated their systems in a manner consistent with the performance standard. EPA's record includes approximately 250 total studies related to impingement (see TDD Exhibit 11A–1).

Despite the overwhelming evidence that the 12 month percent survival performance standard of 24 percent was consistent with demonstrated performance for the best technology, EPA considered other alternatives that might incorporate more variability into a performance standard. EPA concluded that none of the alternatives were consistent with the need for facilities to demonstrate ongoing maintenance and operations over a long period of time, such as a year. Any alternative would be less stringent and would allow facilities to target long-term performance at a level that would be less than the optimal performance demonstrated by facilities with the technology in place. Further, the 12-month average impingement mortality performance standard will require a facility to actively evaluate performance during the 12 month period enabling the facility to optimize the technology to improve performance to counterbalance a result above the standard by one below the standard. If EPA had included a monthly average standard, it would have similarly needed to incorporate allowances for exceedances. Allowing for exceedances would have provided no incentive for improving operations for such exceedances. Therefore, EPA determined that the 12 month impingement mortality performance standard is sufficient to ensure performance consistent with best technology available. For this reason, EPA is not promulgating the monthly average that was included in the proposal. EPA's decision also is consistent with effluent guidelines where compliance with the monthly average limitation is not required for facilities subject to a longer term limitations such as an annual average limitation (e.g., pulp and paper 40 CFR 430 Subpart B AOX limitation).

EPA did not include in the final rule a number of requirements it had considered at proposal. The proposed rule would have required the seasonal deployment of barrier nets on estuaries and oceans as one element of the best technology available for minimizing the impingement mortality of shellfish. EPA has opted not to include any specific requirements for shellfish in the final rule, because EPA's review of the impingement data it used to develop today's final rule impingement performance standard includes data that incorporate shellfish survival as part of the performance standard. Further, as previously explained, the final rule provides for the Director to establish additional requirements where necessary.

EPA expects facilities complying with § 125.94(c) of today's rule by compliance option (7) to track their compliance with the 12 month percent impingement mortality performance standard on an ongoing basis and to proactively modify their technology or operations when a trend in the sampling suggests that they might be in danger of exceeding the 12 month percent impingement mortality performance standard in the future. The 12 month percent impingement mortality performance standard requires that impingement mortality not exceed 24 percent, calculated as the sum total number of fish that were impinged and died within the holding time divided by the sum total number of fish impinged for a 12-month period. EPA expects the ratio will be calculated based either on direct sampling counts, or based on both counts being extrapolated to represent annual counts. Because comments provided data that expanding the proposed 24 to 48 hour holding time requirement would generally not affect the observation of mortality due to impingement, the regulation allows for holding times from 18 to 96 hours.

As explained in more detail in Section VI.E and G below, the BTA technology for impingement does not minimize adverse environmental impacts associated with entrainment.

2. Entrainment Standards for Existing Units

As discussed below, EPA is not basing BTA for entrainment at existing units (that is, excluding new units at existing facilities) on closed-cycle recirculating cooling systems, a highly effective technology, because this technology is not available nationally and therefore does not represent BTA. EPA also has not identified any other effective, available and demonstrated candidate technology (or combinations of technologies) for entrainment reduction at existing units that is available nationally. For other entrainment technologies that might be available on a site-specific basis, see Section VI.E.2 below and Chapter 6 of the TDD. EPA did not select the other flow-reduction technologies (such as variable-speed drives and seasonal flow reductions) as the technology basis for entrainment control measures because these technologies are not uniformly best and are not broadly available for most facilities. Further, EPA has not identified a basis for subcategorizing existing units at which flow reduction technologies are feasible. The effectiveness, availability, and utility to a given facility of flow reduction or other entrainment reduction methods depends on site-specific geographical and biological conditions as well as operations of the facility. For example, this is the reason that EPA did not select relocation of a shoreline intake to far offshore as a technology basis for the BTA entrainment standard because this technology is not widely available for most facilities.

3. Impingement and Entrainment Standards for New Units at Existing Facilities

In contrast to existing units, installing a closed-cycle cooling system at a new unit is far less complex. The technology is also highly effective, generally achieving greater than 95 percent reductions in IM and E (mechanical draft (wet) cooling towers achieve flow reductions of 97.5 percent for freshwater and 94.9 percent for saltwater sources, or by operating the towers at a minimum of 3.0 and 1.5 cycles-of-concentration, respectively). These reductions in flow and the concurrent reductions in impingement and entrainment impacts are among the highest reductions in adverse

[71] For example, the Indian Point study states "Because of the preliminary nature of this study, the effectiveness of the continuously operating fine mesh traveling screen has not been fully evaluated. Further studies incorporating controls for survival testing, regulation of spray wash pressures, collection efficiency tests, sampling during peak impingement periods for all important species, and better holding facilities, will provide more conclusive results."

environmental impact possible at an intake structure.[72]

As described below, EPA has concluded that new units, in contrast to existing units, have much greater flexibility in terms of cooling system design, construction scheduling, and other factors that help minimize many of the negative aspects associated with closed-cycle cooling. For a more detailed discussion of this rationale, see below.

Under the final rule, a new unit at an existing facility, where the facility that withdraws or will withdraw more than 2 mgd when the new unit begins operating will have requirements similar to the requirements of a new facility in Phase I. Under the rule, a new unit (as defined at § 125.92(u) and described above) is required to have a flow limited to that which is commensurate with a closed-cycle recirculating system as it would be applied to the new unit. Today's final rule also includes an alternative approach (similar to Track II in Phase I), in which a facility could comply with the new unit standards by demonstrating that the technologies and operational measures employed will reduce the level of adverse environmental impact from any cooling water intake structure used to supply cooling water to the new unit to a comparable level to that achievable by implementing a closed-cycle recirculating system as defined at § 125.92(c)(1).

As discussed above, today's final rule defines a ''new unit'' at an existing facility as a stand-alone unit the construction of which commences after the effective date of today's final rule. New unit includes stand-alone units that are added to a facility for purposes of the same general industrial operation as the existing facility. This is in contrast to the definition of new facility, where a new facility does not include new units that are added to a facility for purposes of the same general industrial activity (40 CFR 125.83). The provision ''for purposes of the same general industrial operation'' is explicitly included in today's final rule definition of new unit at an existing facility for clarity. A new unit may have its own dedicated cooling water intake structure, or the new unit may use an existing or modified cooling water intake structure. Any unit at an existing facility that does not meet the new unit definition in today's rule is subject to the existing unit provisions.

EPA is adopting more stringent requirements for new units at existing facilities because such new units can be designed and constructed without many of the additional expenses and operational disadvantages associated with retrofitting an existing unit to closed-cycle cooling. For example, the incremental downtime that can be associated with retrofitting to closed-cycle cooling is avoided altogether at a new unit. In addition, when new units are added, the condensers can be configured for closed-cycle, reducing energy requirements (by substantially reducing the turbine backpressure energy penalty) and associated air emissions.

The three factors that led EPA to reject closed-cycle cooling as BTA (described below in Section E) are far less relevant for new units at existing facilities than for retrofitting existing units. This section discusses why EPA concluded that each factor is not a significant concern for new units, and why the record supports EPA's conclusion that closed-cycle cooling is an available and feasible technology for new units at existing facilities.

• Land Availability: In contrast to retrofitting the entire existing facility, the amount of space dedicated to closed-cycle for the new unit will be limited to the new unit rather than the entire facility. As a result, space constraints will be much less of an issue. New units also present the opportunity to design an optimized closed-cycle recirculating system for the new unit. Retrofitting an existing facility for the full intake flow of the facility would require a facility to identify (or possibly obtain) enough space to accommodate the cooling towers and associated equipment. Furthermore, new units and their corresponding cooling system can be built in stages rather than as a facility-wide retrofit, and since the new unit has not yet been built, there is no energy reliability concern (discussed further below).

• Air Emissions: EPA expects that emissions are significantly less of a concern at new units. The condensers will be optimized for closed-cycle, reducing energy requirements, and high-efficiency cooling towers can be incorporated into the design of the new unit, potentially allowing for smaller cooling towers to be installed. Turbine backpressure and the associated energy penalty can be substantially reduced in a new unit, but EPA acknowledges new units will still have auxiliary power consumption for fans. Therefore energy penalties and air emissions for tower operations can be minimized (though not eliminated). The emissions effects of requiring closed-cycle cooling at new units at existing facilities is similar to the effects of this requirement at new facilities and will not pose an unacceptable impact. For more information, see Chapters 6, 8, and 10 of the TDD. Further, the new unit is likely to be more efficient and emit less pollution than existing units, therefore net emissions are expected to decrease as new units replace older, less efficient units.

• Remaining Useful Plant Life: This is clearly not an issue for new units. A new unit has its full useful life remaining and thus would experience the maximum possible reductions in adverse environmental impacts throughout that useful life.

EPA does not expect that the requirements for new units at existing facilities will be a disincentive for facilities to repower existing units. The requirements only apply to stand-alone units. Requirements for entrainment at repowered units will thus be determined by the Director. EPA notes, however, for facilities that do choose to repower an existing unit, the costs of employing a closed-cycle cooling system are not a barrier, as described above. In fact, some facilities may find closed-cycle cooling to be less costly over the long-term. For example, in locations with limited water resources such that once-through cooling of an additional unit is not possible, overall reliability will be increased by using closed-cycle cooling systems.

EPA also recognizes that installing closed-cycle cooling systems at new units is a prevailing trend in industry, regardless of the regulatory requirements imposed by today's final rule. For example, see DCN 12–6672 in the record for today's rule, and DCNs 2–009 and 4–4023C (from the Phase I and Phase II dockets, respectively). These documents show that, on the basis of responses from facilities to the 316(b) industry questionnaire, facilities constructed in recent years are significantly more likely to employ closed-cycle cooling.

EPA recognizes that at some point in the future, every unit will be rebuilt, replaced or repowered (or retired). EPA projects that approximately 227 MW in new generating capacity per year, will be subject to the new unit provision, reflecting the general industry trend towards more efficient units. EPA's analysis projects an equivalent number of new units at manufacturing facilities will be constructed each year. See the Phase I rule for more information

[72] Note that these metrics are not explicit requirements for closed-cycle recirculating systems. They simply represent what EPA views as examples of characteristics of a properly operated and maintained closed-cycle recirculating system, as defined at § 125.92(c)(1).

regarding the affordability and barrier to entry analysis for new construction.

EPA notes that the new unit provision is an important element of the final rule, given the generally long lifespan of equipment at industrial facilities. For example, generating units at a power plant are often projected to have a 50-year lifespan. As a result, these facilities have a slow rate of ''evolution'' in adopting newer technologies. By requiring closed-cycle cooling in new units, EPA is ensuring (along with the Phase I rule) that no new once-through cooling units or facilities will be built.

E. Option Selection

After considering all factors identified above, EPA has concluded that it should base the BTA impingement mortality standard for existing units on the performance of traveling screens (e.g., modified Ristroph screens and equivalent modified traveling screens with fish-friendly fish returns)—the ''best technology available'' for minimizing impingement mortality. While there are a number of technologies that may perform as well as or better than traveling screens, these technologies were not feasible or available on a nationwide basis and thus were not the ''best technology available'' for standard setting purposes. Moreover, the impingement mortality standard for existing units provides a number of alternatives, including some of these other technologies, for compliance with the standard. EPA based the BTA impingement mortality standard for existing units on the performance of traveling screens because EPA concluded that this technology is effective, widely available, feasible,[73] and does not lead to unacceptable non-water quality impacts.

As explained above, EPA has not identified a technology or combinations of technologies that EPA concluded is ''best technology available'' for minimizing entrainment at existing units. EPA did not identify a technology for reducing entrainment that is effective, widely available, feasible, and does not lead to unacceptable non-water quality impacts. As such, EPA is unable to identify a nationally applicable BTA technology on which to base the BTA entrainment standard.

While EPA concluded that closed-cycle recirculating systems reduce entrainment (and impingement mortality) to the greatest extent and are the most effective performing technology, after careful consideration of multiple factors, EPA concluded that a closed-cycle recirculating system is not the ''best technology available'' for existing units within the meaning of the statute. It is not the best technology available on a national basis for minimizing adverse environmental impact and should not form the sole basis for the BTA standard for entrainment for the reasons explained below.

EPA also determined that there were no other ''available'' technologies for entrainment whose performance came close to that of closed-cycle recirculating systems. Further, while reduced intake velocity was a very effective control for impingement and may also reduce entrainment of some life stages of fish and shellfish, it does not significantly reduce entrainment of eggs and non-motile stages of larvae, and it is not physically available in many locations.

EPA has broad discretion in what factors it should consider when it determines the best technology available for minimizing the adverse environmental impacts of cooling water intake structures. As both the U.S. Supreme Court and the Second Circuit Court of Appeals have underscored, section 316(b) is ''sui generis,'' in a class by itself, unencumbered by ''specified statutory factors,'' *Entergy Corp.* v. *Riverkeeper, Inc.,* 556 U.S. 208, 222 (2009); *Riverkeeper, Inc.* v. *EPA,* 358 F, 3d 174,187 (2d Cir. 2004). The Second Circuit explicitly rejected the argument that, because section 316(b) does not mention costs or other factors, EPA cannot give costs or other factors ''any'' weight in deciding what is the best technology. *Riverkeeper, Inc.,* 358 F.3d at 195. Furthermore, the Second Circuit recognized that EPA may base its decision on factors other than the effectiveness of a given technology in reducing impingement and entrainment and that EPA is entitled to deference in deciding what weight to give to the factors it considers in its BTA determination. *Riverkeeper, Inc.,* 358 F.3d at 196.

As noted, costs are one factor EPA may consider in its BTA determination. Here, while EPA did consider costs, costs were not a dispositive factor in the decision to reject closed-cycle cooling as the basis for a uniform national BTA entrainment standard. EPA did not reject closed-cycle cooling here either because it was not economically achievable or because the costs of closed-cycle would exceed its benefits. Instead, EPA rejected closed-cycle cooling as the technology basis for a uniform national BTA entrainment standard based on three factors: Land availability, air emissions, and remaining useful plant life as explained below.

Central to EPA's evaluation of the availability of closed-cycle as BTA was EPA's new understanding of the limitations of technologies other than closed-cycle in reducing entrainment. This presented EPA with a sharper choice than it had in the Phase II rule. For today's rulemaking, EPA took a second look at the data it had relied on in the Phase II rule, particularly in light of new data received since the Phase II rule. As a result, EPA learned that entrainment exclusion does not necessarily equate to entrainment survival (76 FR 22185), a key underpinning to EPA's BTA standards for entrainment in the remanded Phase II rule.

For the remanded Phase II rule, EPA had established national BTA performance standards for entrainment (and impingement) and included a number of different alternative means to achieve the standards. First, if a facility demonstrated that it could achieve reductions in flow associated with closed-cycle cooling, the facility met the BTA performance standards. Alternatively, a facility could demonstrate that it met the entrainment performance standards by a combination of installed technology and operational or other measures (including restoration measures). See 69 FR 41590 for a description of the final Phase II rule. Critical to EPA's decision to provide an array of choices for achieving the national BTA entrainment performance standards was a key factual conclusion. That conclusion was that a number of technologies would achieve performance reducing entrainment that was ''comparable'' to that of closed-cycle cooling. Consequently, for the Phase II rule, EPA established an entrainment performance standard of 60 to 90 percent based on data it reviewed for the Phase II rulemaking. See 69 FR 41598 for information on EPA's rationale for establishing compliance alternatives as part of the final rule.

In the Phase II rule, while EPA looked to the performance of closed-cycle as the benchmark against which it evaluated technologies for the BTA standards, EPA did not mandate the achievement of flow reductions that were in all cases equivalent to closed-cycle. Given that the available data supported the view that there were other much less expensive technologies that obtained significant reductions in entrainment, EPA was comfortable with a BTA standard that required achievement of a level of performance

[73] As part of the feasibility determination, EPA found that the costs associated with the IM standards are reasonable for the industry as a whole.

that was generally comparable though not equivalent to closed-cycle.

Since the Phase II rulemaking, EPA has received new data and learned that its understanding of entrainment technology performance was incomplete. Following the remand of the Phase II rule, EPA reexamined the data as well as new information on the performance of various entrainment control technologies it had previously reviewed. As a result, EPA determined that its conclusion regarding the capability of these other technologies—a conclusion on which the Agency had based the Phase II BTA performance standards—was no longer supported by the data EPA had before it.

There is a second additional consideration that further required EPA to focus renewed attention on how widely available closed-cycle cooling in fact was nationally. The Second Circuit decision in the Phase II rule removed restoration as a compliance option that EPA could consider. The decision underscored that restoration measures—one compliance option included in the Phase II rule—were not an available tool for complying with any 316(b) standard. However, at the time of the Phase II promulgation, EPA expected some facilities would use restoration in lieu of closed-cycle cooling, thus making closed-cycle or reductions commensurate with closed-cycle feasible (76 FR 41609). With the court decisions that restoration was not an available tool for compliance, compliance with a standard based on closed-cycle cooling alone is less feasible than EPA had expected at the time of the Phase II promulgation.

The changed landscape has narrowed markedly EPA's range of options with respect to the technology basis for today's BTA standards. The gap between the performance of the most effective entrainment reduction technologies (closed-cycle) and other less expensive technologies has widened significantly. EPA's narrowed range of compliance technology choices required EPA to look even more closely at the feasibility of closed-cycle cooling and reduced flow. As the Second Circuit has noted, EPA is clearly entitled to make its choice among alternative BTA technologies based on more factors other than just a technology's effectiveness in reducing impingement and entrainment. *Riverkeeper, Inc.,* 358 F.3d at 196. EPA identified three factors as significant in its decision to reject closed-cycle cooling as the sole technology basis for a national BTA entrainment standard. The three factors that collectively support rejecting closed-cycle cooling systems as a uniformly applicable BTA for existing facilities (except new units) are land availability, increased air emissions and remaining useful life.

1. Land Availability and Geographical Constraints Could Be a Factor on a Local Basis

While EPA's record indicated that the majority of facilities have adequate available land to retrofit to closed-cycle cooling, some facilities have land constraints.[74] While EPA originally estimated as many as 23 percent of facilities would not have enough space,[75] it observed on site visits that some facilities with a small parcel of land could still install closed-cycle cooling by using creative engineering solutions. On the other hand, EPA found that some facilities with large acreage could not feasibly install cooling towers because of local zoning or other local concerns. Thus, existing physical space at the facility was not the only factor contributing to uncertainty about land availability. Further review has shown that setback distances to mitigate noise and plume abatement (based on GPS mapping of residential areas) act as an additional constraint on land available for retrofitting to closed-cycle, and the cost of acquiring new land may be prohibitive for some facilities. Consequently, EPA estimates that 25 percent or more of facilities might have one or more constraints on land availability that would limit the ability to retrofit for cooling towers for the entire facility. EPA lacks adequate support to indicate that land constraints can be accommodated at existing facilities.

EPA also attempted to determine criteria based on the data in its record that would enable it to define a threshold for determining land availability on a nationwide basis, but was unsuccessful. For example, one analysis explored a threshold of approximately 160 acres per GW (gigawatt) below which a facility could not feasibly install cooling towers. Based on acres and the footprint of the facility and its surroundings (primarily those sites for which EPA conducted site visits), EPA found such an approach did not accurately identify which facilities could feasibly install closed-cycle.

2. Increased Air Emissions Could Be a Factor on a Local Basis

As previously discussed, retrofitting closed-cycle cooling (without also repowering) would result in increased air emissions of various pollutants, including particulates, sulfur dioxide, nitrogen oxides, mercury, and greenhouse gases, among others.[76] As a result of installing closed-cycle cooling structures, fossil-fueled facilities would need to burn additional fuel, thereby emitting additional PM, CO_2, SO_2, NO_X, and Hg. Two factors are responsible: (1) The need to compensate for energy required for operating cooling towers, and (2) slightly lower generating efficiency attributed to higher turbine backpressure when the condenser is not replaced with one optimized for closed-cycle operation when retrofitting existing units (also referred to as the energy penalty). While both of these factors contribute to increased air emissions, the larger contributor to projected increased air emissions is by far the energy penalty.

The impact of the increased emissions varies according to the local circumstances. The increased emissions could consist of stack emissions from increased fuel usage, cooling tower emissions, and plumes of water vapor. EPA's analysis suggested that the most significant impacts would be increased $PM_{2.5}$ emissions, which are associated directly with an increase in human health effects. EPA notes that cooling plume abatement and drift elimination technologies exist to address cooling tower emissions (and EPA included costs for such technologies in its analysis of Proposal Options 2 and 3). Further, EPA expects most effects of the particulates from cooling tower emissions would be limited to the immediate vicinity, confined wholly to the facility property. (See DCN 10–6954.) Therefore, EPA's primary concern is increased air emissions associated with additional fuel usage due to the energy penalty when retrofitting to cooling towers. EPA's review of emissions data from E–GRID (year 2005) suggests that impacts from these pollutant discharges could be significant. These include the human health and welfare and global climate change effects—all associated with a

[74] For example, in the case of fossil fuel facilities, scrubber controls may already have been required to comply with air rules and standards. This may reduce available land for closed-cycle.

[75] EPRI reported at least 6 percent of sites it evaluated were deemed ''infeasible'' because no space was available on which to locate a cooling tower. (DCN 10–6951) While EPA does not have access to the facility level data, EPRI's report supports EPA's conclusion that there is significant uncertainty around space constraints for facilities to install closed-cycle cooling.

[76] EPA recognizes that retrofitting closed-cycle cooling could be combined with other energy efficiency or pollution control technologies with the net effect of reducing air emissions; however, facilities could (and may be required to under other rules) install such technologies anyway, without converting to closed-cycle cooling.

variety of pollutants that are emitted from fossil fuel combustion. EPA is not able to quantify the frequency with which facilities could experience these local impacts, and therefore has concluded that the proper forum to address such local impacts fully is in a site-specific setting.

3. Remaining Useful Plant Life Could Be a Factor on a Facility Basis

A number of facilities are nearing the end of their useful life. Considering the long lead time to plan, design, and construct closed-cycle cooling systems, EPA determined that the Director should have the latitude to consider the remaining useful plant life in establishing entrainment mortality requirements for a facility. The remaining useful plant life, along with other site-specific information, will affect the entrainment reduction of closed-cycle cooling at a facility. For example, retrofitting to a closed-cycle system at a facility that is scheduled to close in three years will result in little entrainment reduction as compared to retrofitting to closed-cycle at a facility that will continue to operate for a significantly longer period.

The Decision To Establish a National BTA Standard Requiring Site-Specific Determination of BTA Entrainment Controls

Once EPA determined that a ''one-size-fits-all'' approach for entrainment for existing units is not generally feasible, it is appropriate to assess the required controls on a site-specific basis. Therefore, for existing units, EPA decided to adopt as the BTA entrainment standard an overarching regulatory framework under which the Director will establish BTA entrainment requirements on a site-specific basis following prescribed procedures and applying specified factors for decision-making prescribed in the regulation and as described below.

EPA concluded that site-specific proceedings are the appropriate forum for weighing all relevant considerations in establishing BTA entrainment requirements. Closed-cycle cooling is indisputably the most effective technology at reducing entrainment. Closed-cycle reduces flows by 95 percent and entrainment is similarly highly reduced. But given that EPA estimates that 25 percent of existing facilities may face some geographical constraints on retrofitting closed-cycle cooling and concerns about air emissions and the remaining useful life of a facility, EPA rejected the option of requiring uniform entrainment controls based on closed-cycle cooling. Instead, EPA elected to adopt as the entrainment standard a more flexible process in which, following consideration of a host of factors, the Director will prescribe 316(b) entrainment conditions appropriate at a particular site. For additional discussion on how a site-specific consideration of entrainment control requirements will be implemented, see Section VIII below.

EPA has several reasons for adopting the framework approach as the BTA standard for entrainment. As explained, the record shows that though closed-cycle cooling is effective, it is neither widely available nor feasible, and has significant unacceptable non-water quality impacts. While EPA cannot identify with precision the extent of these limitations on installing closed-cycle cooling systems nationwide, the record indicates that the circumstances are neither isolated nor insignificant. In light of this, EPA decided not to establish closed-cycle cooling as a presumptive BTA entrainment standard, pending a site-specific demonstration of the limitations. Instead, entrainment control requirements will be determined in a site-specific setting where the opportunity for local input in decision-making process will be maximized.

With regard to new units at existing facilities, based on the performance of properly operated cooling tower operation and the availability, feasibility and affordability of closed-cycle cooling at new units, EPA selected closed-cycle recirculating systems based on wet cooling towers as BTA. For a discussion of how the three factors (availability, feasibility and affordability) relate to new units, see Section VI.D.3. Consistent with the Phase I rule for new facilities, EPA has also included a compliance alternative allowing a facility to show performance comparable to that of a closed-cycle recirculating system. The new unit provisions in today's final rule are essentially the same as the requirements for new facilities under the Phase I rule.

F. Other Options Considered for Today's Final Regulation

EPA considered several other options for the BTA standards in developing today's rule, but ultimately rejected them. This section includes a discussion of these options, as well as some technologies that EPA considered, but did not include as compliance alternatives to the impingement mortality standards.

1. Proposal Option 4—Flexible Impingement Mortality Controls Similar to Final Rule at Existing Facilities With DIF of 50 mgd or More; BPJ Permits for Impingement Mortality and Entrainment at Existing Facilities With Design Intake Flow Between 2 mgd and 50 mgd; Site-Specific Entrainment Standard for Existing Facilities With DIF of 50 mgd or More; and Uniform Impingement Mortality and Entrainment Controls for All New Units at Existing Facilities Similar to Final Rule

At proposal, EPA's preferred option was Option 1, which was the option closest to today's final rule, and the starting point for the description of the changes to the rule in Section V above. At proposal, EPA also considered a variant of Option 1, called Option 4, which changed the impingement mortality requirements for facilities under 50 mgd from the performance standard in Option 1 to BTA as determined by best professional judgment. In the case of an existing facility below 50 mgd that added a new unit, the flow associated with the new unit would have been subject to the uniform entrainment requirements based on closed-cycle cooling. Finally, all existing facilities withdrawing more than 2 mgd of DIF would have been subject to entrainment requirements established on a site-specific basis, with the exception noted above for new units. The option analyzed here, called Proposal Option 4, is likewise similar to the final rule, but for the impingement standard based on BPJ for facilities between 2 and 50 mgd.

EPA ultimately rejected Proposal Option 4 because EPA found that the technologies on which the impingement mortality performance standard of today's final rule is based are available, feasible, demonstrated, and affordable for all regulated facilities on a national basis. Moreover, EPA's analysis showed that the difference in the total costs for the two options was nominal. Additionally, EPA notes that many facilities with a DIF under 50 mgd already use closed-cycle cooling and would have minimal burden under the final rule. These facilities would have no difficulty complying with the requirements EPA is establishing in today's final rule. Proposal Option 4, by not distinguishing between those facilities under 50 mgd that have already minimized adverse environmental impacts from those that have not, masks the actions that would have to be taken by the latter group to comply with today's final rule. In addition, the flexibilities introduced in the June 11, 2012 NODA and included in today's final rule applied to all facilities, rather than taking the Option 4 approach at proposal of providing for more Director discretion for only the smaller withdrawing facilities. EPA also concluded that the data collection activities required under the final rule will be more protective of threatened and endangered species because they provide information on a larger number of facilities than Proposal Option 4 for consideration by the Director in permitting decisions. Lastly, EPA acknowledges that Proposal Option 4 is more burdensome to permitting authorities than is the final rule, as it requires more case-by-case decision making.

2. Proposal Option 2—Flexible Impingement Mortality Controls Similar to Final Rule at All Existing Facilities That Withdraw Over 2 mgd DIF; Site-Specific Entrainment Standard for Existing Facilities With DIF at or Below 125 mgd; Require Flow Reduction Commensurate With Closed-Cycle Cooling by Facilities Greater Than 125 mgd DIF; and Uniform Impingement Mortality and Entrainment Controls for All New Units at Existing Facilities

As previously explained, EPA assessed a number of different technologies that reduce impingement mortality and entrainment as the possible basis for section 316(b) requirements. EPA concluded that closed-cycle recirculating systems (based on wet cooling towers) are the most effective technology for reducing impingement mortality and entrainment. Notwithstanding that conclusion, EPA has decided not to establish a performance standard for impingement and entrainment based on closed-cycle recirculating systems for existing facilities. Furthermore, EPA found that there are no other effective technologies for entrainment that are available nationally. As described previously, each of the three factors for rejecting closed-cycle cooling as BTA for entrainment would also apply in the case of Proposal Option 2, despite the smaller number of facilities that would be subject to a requirement to retrofit. The technology basis for entrainment mortality controls for facilities greater than 125 mgd DIF under this option would have been wet cooling systems. The constraints discussed above that are associated with retrofitting a large portion of the universe of affected facilities, led EPA to conclude that requiring closed-cycle cooling on a uniform basis scale was not appropriate for a national regulation.

EPA notes that it proposed multiple options that included closed-cycle, and solicited comment on all aspects of closed-cycle cooling. After fully considering all comments and data, EPA still finds closed-cycle cooling is not the ''best technology available for minimizing adverse environmental impact'' required by section 316(b). Because of a combination of concerns over feasibility/availability, air emissions, and remaining useful life of the facility, EPA has rejected closed-cycle recirculating systems as the basis for national impingement and/or entrainment controls. Nor is EPA able to identify a subcategory for which these concerns no longer apply. Moreover, the complex interaction of all of these factors at individual sites does not lend itself to other regulatory options that would require closed-cycle recirculating systems with an ''off ramp'' if any of the factors were shown to result in unacceptable impacts because this would create a presumption for closed-cycle cooling rather than an equal balancing of all relevant factors. EPA decided not to establish any presumptive BTA entrainment outcome. EPA finds the entrainment standards framework in today's final rule will provide a consistent, more efficient, and more effective approach than standards with an ''off ramp.''

3. Proposal Option 3—Flexible Impingement Mortality Controls at All Existing Facilities That Withdraw Over 2 mgd DIF; Require Flow Reduction Commensurate With Closed-Cycle Cooling at All Existing Facilities Over 2 mgd DIF

Proposal Option 3 was, in many ways, the same as requiring closed-cycle cooling at all existing facilities. As described above, each of the three factors for rejecting closed-cycle cooling as BTA for entrainment would apply with equal force for Proposal Option 3. As a result, EPA has concluded Proposal Option 3, similarly, is not appropriate as BTA for entrainment.

4. Proposal Option 4 Variant

EPA also considered a variant of Proposal Option 4. As compared to Proposal Option 4, this variant did not include flexible alternatives for complying with the BTA impingement mortality standards (including pre-approved and streamlined alternatives), but did adopt the 50 mgd threshold to determine those facilities for which the Director has more discretion in determining BTA via BPJ. EPA analyzed this option to directly compare the effects of introducing flexible IM compliance alternatives at all facilities (as the final rule does) to the effects of introducing greater Director discretion for a subset of facilities, via BPJ permitting (as the Proposal Option 4 variant does). The preferred option at proposal, Option 1, was estimated to be more costly than Option 4 (Option 1 was estimated to cost $384 annually as compared with $327 million annually for Option 4). Under the analysis supporting the final rule the EPA is adopting today, however, today's final rule is estimated to cost $275 million annually in comparison with an estimated cost of $284 million annually for the Proposal Option 4 variant. Thus, EPA has concluded that providing flexible alternatives for compliance with the BTA IM standard at all facilities is both more effective at reducing costs to society and more readily justified as best technology available as compared to the approach of introducing greater Director discretion for only a subset of facilities (below 50 mgd). Hence, EPA rejected the Proposal Option 4 variant, and the approach of introducing greater Director discretion for only a subset of facilities (below 50 mgd).

5. Proposal Option 2 Variant

EPA also considered a variation of Proposal Option 2 that would have used 125 mgd AIF rather than 125 mgd DIF as the threshold. However, as described above, EPA rejected Proposal Option 2 and, for the same reasons, rejected this variant of Option 2.

6. Site-Specific Approach To Addressing Impingement

Many commenters (primarily from manufacturing facilities) commented that EPA should adopt a site-specific approach to addressing impingement mortality, similar to that employed for entrainment. As a result, EPA also considered an approach that would have established both impingement mortality and entrainment requirements fully on a site-specific basis taking into account for the particular facility, among other factors, those previously described as pertinent to EPA's 316(b) BTA determination. EPA rejected a fully site-specific approach for impingement controls principally because low-cost technologies for impingement mortality are available, feasible, demonstrated, and affordable for facilities nationally. Because technologies are available, a fully site-specific approach would place an unnecessary additional burden on state permitting resources. Moreover, the final impingement mortality standard includes several alternatives that allow site-specific demonstration that a particular technology performs at a level representing the best technology available for the site. EPA is instead promulgating a modified version of the proposed rule, adding several elements of flexibility (i.e., compliance alternatives), and thus directly addressing many of the concerns raised by these commenters.

7. Pre-Approved Technologies

Many commenters requested that EPA pre-approve technologies that, once installed, would obviate the need for further regulatory conditions such as periodic monitoring. This is similar to the approach taken for cylindrical wedgewire screens in the remanded 2004 Phase II rule (see 69 FR 41693). EPA has adopted, in significant measure, commenters' suggestion in the BTA impingement mortality standard in today's rule by including several pre-approved and several streamlined compliance alternatives in the form of technologies that may be approved following a demonstration of required performance, so long as the facility shows that its alternative technology is operating in a manner that minimizes adverse environmental impacts. As an option for achieving the impingement mortality standards, a facility may install and operate specified impingement controls whose performance is comparable to or better than the technology EPA concluded was the ''best technology available'' for impingement mortality reductions:

- Closed-cycle recirculating systems, defined at § 125.92(c)
- Existing offshore velocity caps, defined at § 125.92(v)
- Technologies that result in a design intake velocity less than or equal to 0.5 fps, including most modern cylindrical wedgewire screens

Although this rule leaves the BTA entrainment determination to the Director, with the possible BTA decisions ranging from no additional controls to closed-cycle recirculating systems plus additional controls as warranted, EPA expects that the Director, in the site-specific permitting proceeding, will determine that facilities with properly operated closed-cycle recirculating systems do not require additional entrainment reduction control measures. Refer to Section E.1 for the EPA's rationale for selecting these controls.

G. Final Rule BTA Performance Standards

The rule establishes the following BTA standards for Impingement Mortality and Entrainment: Impingement Mortality Standards at All Existing Units at Existing Facilities that withdraw greater than 2 mgd DIF; an Entrainment Standard that requires site-specific entrainment controls determined by the Director for Existing Units at Existing Facilities that withdraw over 2 mgd DIF; BTA standards for impingement mortality and entrainment for new units at existing facilities. The previous section described the other options that EPA considered but ultimately rejected, and the basis for those decisions.

1. Impingement Mortality Controls for Existing Units at Existing Facilities for the Final Rule

Today's final rule provides a facility a number of alternatives for complying with the BTA impingement mortality standard. As discussed more below, EPA's BTA impingement mortality standard is based on EPA's conclusion that, on a national basis, modified traveling screens with fish-friendly return systems are the best performing technology available for impingement mortality reduction. But EPA is not requiring compliance with the BTA impingement mortality standards only through monitoring data that demonstrates achievement of the numeric reduction in mortality levels that EPA has determined well-operated modified traveling screen will achieve. Rather, the final rule allows facilities to comply by employing any of seven alternatives, including monitored compliance with a numeric impingement mortality performance standard.

Based on its review of available data and information submitted by commenters, EPA identified a number of other technologies and operational measures that could achieve equivalent, or better, performance to the impingement mortality reductions achieved with modified traveling screens that may be available for some sites. Thus, the final rule provides seven alternatives for complying with the BTA impingement mortality standards. These include three compliance paths based on pre-approved technologies, and three compliance paths that offer a streamlined approach to compliance. EPA expects the majority of facilities will use one of these six options to comply with the BTA impingement mortality standards (see Exhibit VIII–1 for more information).

The following pre-approved technologies will comply with today's rule and are associated with minimal monitoring and reporting of operational and/or design parameters. These technologies are (the numbering reflects the numbering in § 125.94(c)): Operating (1) a closed-cycle recirculating system; (2) a cooling water intake structure that EPA or the State NPDES permitting authority determines has a design maximum through-screen intake velocity of 0.5 feet per second; or (4) an existing offshore velocity cap. The general intent behind a compliance path based on a pre-approved technology is to provide a level of certainty to the regulated entity that they would be deemed compliant with the relevant rule requirements by designing, installing, and operating the technology as specified in the regulation. The three pre-approved compliance alternatives are each based on a particular technology approach. The permit for each compliance alternative will necessarily include criteria, design standards, and operational conditions specific to the pre-approved technology. The compliance paths based on pre-approved technologies in today's final rule include simplified permit application requirements (such as reduced or minimal study), documentation, or reduced monitoring, and will therefore result in greatly simplified implementation. In today's final rule, there are no biological compliance monitoring requirements for any of the three compliance paths based on pre-approved technologies.

Under the streamlined alternatives, a facility must demonstrate to the Director that traveling screens or some combination of technology controls or operational measures represent BTA performance under the conditions at the site. The three streamlined compliance alternatives are (the numbering reflects the numbering in § 125.94(c)) operating (3) a cooling water intake structure that EPA or the State NPDES permitting authority determines has an actual maximum through-screen intake velocity of 0.5 feet per second; (5) modified traveling screens whose demonstrated performance represents the best technology available for impingement reduction at the site; or (6) a system or combination of technologies or operational measures whose demonstrated performance is the best technology available for impingement reduction at the site. In order to demonstrate BTA performance, a facility will need to conduct a two-year site-specific study at the same time it conducts its source water characterization and Entrainment Characterization Study. This study must demonstrate that its modified traveling screens, or combination of technology controls and operational measures, have been adjusted and optimized so as to minimize impingement mortality. If the Director concludes that the facility has demonstrated optimized performance for its controls, the facility will have no subsequent biological monitoring and reporting requirements as compared to a facility that complies using the impingement mortality performance standard. If the screens or other measures are not already installed, the Director may approve postponing the two-year study to be conducted after the entrainment determination has been made. These three streamlined compliance alternatives are based on a technology or suite of technologies and practices with more variable performance, and as such necessitate some degree of study, in order to optimize technology performance for the site-specific conditions encountered by a facility. A streamlined compliance alternative may require some level of monitoring, but once the optimal performance of the technology has been identified, conditions included in the permit specifying optimal operation ensure that the streamlined alternative is similar to or better than the impingement mortality performance standard. For example, the streamlined compliance alternatives also do not require biological compliance monitoring.

The seventh alternative (at § 125.94(c)(7)) for complying with the BTA impingement mortality standards requires the owner or operator to demonstrate compliance with the numeric impingement mortality performance standard through biological monitoring. Under this alternative, the owner or operator has the flexibility to choose any technology, including a new or innovative technology, provided the compliance monitoring demonstrates the performance standard is achieved.

Each of these seven alternatives is further described below. In addition, further discussion of how each of these alternatives will be implemented may be found in Section VIII.

a. Closed-Cycle Recirculating Systems

As described above, in Chapter 6 of the TDD, and in prior rulemakings, EPA has long recognized the benefits of flow reduction from closed-cycle recirculating systems for reducing impingement (as well as entrainment). A facility employing a closed-cycle recirculating system will typically reduce impingement by more than 95 percent. As a result, a facility may choose to comply with the BTA impingement mortality standards in today's final rule by demonstrating that it uses a properly operated and maintained closed-cycle recirculating system.

EPA estimates that approximately 18 percent of intake structures (i.e., those that already have an existing closed-cycle recirculating system, plus facilities located in California and New York, whose State regulations are at least as stringent as the final rule) will choose this alternative.

EPA does not have the data to determine precisely which impoundments are serving as part of a closed-cycle recirculating system as defined at 40 CFR 125.92(c)(2). However, EPA is aware that some facilities have created their impoundments in a water of the U.S. as part of their cooling system. EPA does not intend to eliminate the use of such lawfully created impoundments for their intended purpose, as doing so could result in a large number of stranded assets. If the cooling system with the impoundment minimizes the withdrawal of make-up water for cooling purposes, the Director may determine the cooling system meets the definition of a closed-cycle recirculating system.

b. Reduced Intake Velocity

EPA has long recognized the relationship between impingement and intake velocity. EPA conducted an analysis of fish swim speeds in the Phase I rule (see 66 FR 65274, December 18, 2001) and concluded that a design through-screen velocity of 0.5 fps is protective of 96 percent of motile organisms. However, EPA did not select intake velocity as the technology basis for the BTA impingement mortality standards. Although the performance of 0.5 fps intake velocity achieves greater reduction in impingement mortality than the technology on which the BTA impingement mortality standards are based, reducing a facility's intake velocity is not widely available or feasible for all existing facilities (see Chapter 6 of the TDD).

EPA is including reductions in intake velocity as an alternative for complying with the BTA impingement mortality standards through reduced intake velocity. A facility choosing this alternative must demonstrate that (1) the through-screen design velocity could not exceed 0.5 fps or (2) the actual intake velocity does not exceed 0.5 fps.

EPA estimates that approximately 34 percent of intake structures will choose this alternative. This estimate includes facilities that have an existing intake velocity of 0.5 fps or less, plus those facilities that are projected to install a technology that would reduce their intake velocity (larger intake, wedgewire screens, or variable speed pumps).

i. Design Intake Flow Basis

Consistent with EPA's determination in its earlier 316(b) regulatory efforts, the final rule allows a facility to comply with the BTA impingement mortality standards by demonstrating that its intake has a maximum through-screen design velocity of 0.5 fps. EPA concluded that facility's operating at this through-screen design velocity will protect the vast majority of impingeable aquatic organisms. Facilities choosing to comply with the BTA impingement mortality standards may not average velocity across multiple intakes at a facility.

ii. Actual Intake Flow Basis

EPA is also adopting a provision to allow facilities to demonstrate that the through-screen intake velocity at an intake structure does not exceed 0.5 fps on the basis of the intake's actual flow. (Again, note that facilities choosing this compliance alternative may not average intake velocity across multiple intakes.) In contrast to design flow above, a facility with an intake having a design through-screen intake velocity greater than 0.5 fps may be operated at a reduced capacity and therefore may withdraw cooling water at a velocity less than 0.5 fps. As long as the actual intake flow is such that the velocity remains at or below 0.5 fps, the reductions in impingement (and subsequently, impingement mortality) remain the same as a facility with a maximum design through-screen intake velocity of 0.5 fps. As described below, a facility will be required to monitor its intake flow and report this data to the Director to verify that intake flows do not exceed 0.5 fps. This approach also permits the Director to allow brief periods where the intake velocity will exceed 0.5 fps under extreme conditions.

c. Existing Offshore Velocity Caps

A number of commenters stated that EPA should consider existing offshore intakes fitted with velocity caps to be pre-approved and complying with the BTA impingement mortality standards. Locating submerged intakes in the deeper regions of larger waterbodies (particularly outside the littoral zone [77]) has the potential to reduce both impingement and entrainment (I&E), due to the lower densities of aquatic organisms as compared to a shoreline-based intake. EPA has identified 11 facilities with offshore velocity caps, and reviewed a number of studies documenting the performance of these

[77] The littoral zone extends from the shoreline to roughly the edge of the continental shelf.

facilities. These studies show that the impingement reduction performance of intakes submerged far offshore with velocity caps is dependent on site-specific conditions. The data show that solely locating an intake far offshore (i.e., without also employing a velocity cap) achieves a 60 to 73 percent reduction in impingement, and therefore does not achieve impingement mortality reduction comparable to that of well-operated modified traveling screens. Similarly, the data also show that velocity caps alone achieve a 50 to 97 percent reduction in impingement, and therefore could result in compliance performance comparable to or better than modified traveling screens in some, but not in all cases. However, the combination of an existing intake located far offshore (i.e., approximately 850 feet, as identified in the data for Nine Mile Unit 1 and Oswego Unit 5) in combination with use of a velocity cap will result in performance that exceeds the 12-month average impingement mortality performance standard (alternative seven described above).[78] [79] Because there is some amount of uncertainty in measuring distances from a shoreline, including but not limited to due to variations in water levels, storm swells, or tidal excursions, EPA has set the minimum distance offshore at 800 feet. As a result, the final rule at § 122.95(c)(4) allows a facility to comply with the BTA impingement mortality standards with an existing offshore intake with an existing velocity cap located at least 800 feet offshore, based on the performance data from the 11 identified facilities.

As noted above, the record shows all existing facilities with a velocity cap located at least 800 feet offshore will meet or exceed the 12-month average mortality performance standard of § 125.94(c)(7). EPA does not have data showing velocity caps located at lesser distances offshore will consistently achieve the impingement mortality performance standards, but is aware that some facilities may be able to achieve the impingement mortality standards through a combination of technologies that includes an offshore location. For example, the Office of Naval Research states that the littoral zone in ocean environments generally extends from the shore to 600 ft out in the water (ONR 2013). SEAMAP data in EPA's record shows installing the intake to depths where there is a lower concentration of living organisms (i.e., at least 65 feet) is also expected to decrease environmental impacts associated with intake operations. Therefore, the final rule allows facilities with intake structures at significant distances offshore to demonstrate the performance of their technology under § 122.95(c)(6), as further discussed below.

In addition facilities may opt to construct an offshore velocity cap at new locations. In those circumstances, the facility will need to demonstrate that theperformance of its velocity caps is the best technology available for impingement reduction under the alternative found at § 122.95(c)(6). For more information, see DCN 12–6601.

EPA estimates that approximately 1 percent of intake structures (i.e., those with an existing velocity cap meeting the definition at § 125.92(v) will choose this alternative.

d. Install Modified Traveling Screens

In the June 11, 2012 NODA, EPA discussed a streamlined compliance option that would provide facilities with a less burdensome alternative than the proposed rule. In the final rule, EPA has included an option at § 125.95(c)(5) for facilities that install traveling screens—the technology that forms the basis for the numeric IM performance standards. Under this option, the facility must demonstrate to the Director that it will install and operate modified traveling screens as defined at § 125.92(s) that are or will be optimized to minimize IM mortality at the site. The facility will also be required to submit an impingement technology performance optimization study (§ 122.21(r)(6)) which will include a 2-year optimization study for the intake technology. The facility will conduct 2 years of monthly impingement data collection, during which the facility will seek to optimize the technology performance to minimize impingement mortality. This study is intended to determine the optimal configuration and operating conditions of modified traveling screens and the fish handling and return systems for that intake to be consistently protective of aquatic organisms. During the course of the study, EPA expects that a facility will evaluate the interim results and make changes to the technology or operating conditions as needed to identify the most appropriate set of operational characteristics to ensure long-term success. For example, a facility could adjust the spray wash pressure, adjust the rotating speed of the screens, rotate the screens more frequently, re-angle the fish sluicing sprays, ensure adequate water in the return flume, design the fish return to avoid avian and animal predation on the aquatic organisms, and locate the fish return in such a way to avoid predation. Once a facility has optimized its technology performance, the study will identify operational measures that will serve as observable and enforceable permit conditions. As evidenced by the data used in determining the performance standard, by requiring facilities to study the conditions for optimized performance, many facilities will achieve impingement mortality reductions much greater than the 12-month average impingement mortality performance standard without significant additional investment. Biological data collection beyond this two-year study will not be required. The facility will simply be required to ensure that it is operating its technology under the identified conditions for optimized performance. If the Director concludes that the screens will achieve optimized performance, the Director will also incorporate operating conditions to ensure optimized performance as terms of the facility's NPDES permit.

As discussed in the NODA and Chapter 4 of TDD, EPA's data indicate that most facilities employ traveling screens.[80] EPA anticipates that, as a result, many facilities will view the streamlined screen-based compliance route as a logical choice for complying with the final rule. The streamlined option provides an opportunity for a large number of the affected facilities (i.e., those that do not meet the criteria for the other compliance technologies) to demonstrate that their intakes are effectively reducing impingement mortality while significantly reducing the burden on both facilities and regulatory agencies. EPA estimates that approximately 30 percent of intake structures will choose this alternative.[81]

EPA is aware that some facilities have no technologies installed and will choose to install modified traveling screens, and further that some facilities

[78] An existing facility may also choose to install a new offshore intake with a velocity cap, but such a facility would not automatically qualify as meeting the impingement requirements for the final rule. Such a facility would need to demonstrate equivalent performance to the impingement mortality performance standard.

[79] A velocity cap must also include bar racks or other devices to exclude large marine organisms (e.g., seals, turtles) from entering the intake structure.

[80] EPA's technical survey found that 93 percent of electric generators and 73 percent of manufacturers already use screens, the majority of which are traveling screens.

[81] While EPA's data shows 73 to 93 percent of facilities already use traveling screens, EPA notes that many facilities use more than one technology. For example, some of these facilities also have a low intake velocity, an offshore velocity cap, or cooling towers. EPA expects facilities will choose the IM compliance alternative corresponding to these pre-approved technologies before they will choose to comply via optimized performance of their traveling screens.

with traveling screens will choose to either retrofit to modified traveling screens with fish handling and returns. Obviously, the impingement technology performance optimization study cannot be undertaken until the technology is first installed. In this case the NPDES permit would be issued before the completion of the optimization study. EPA expects a permit will be issued that includes a schedule for both the technology installation and the required optimization study. As discussed earlier, the Director can establish interim measures as appropriate (40 CFR 125.94(b)).

e. System of Technologies as the BTA for Impingement Mortality

EPA recognizes that cooling water intake structures have a variety of configurations and facilities may choose to comply with the final rule by using more than one of the compliance approaches outlined above. In the June 11, 2012, NODA, EPA described an approach where facilities would be able to demonstrate ''credit'' toward meeting the impingement mortality requirements by reducing the total number of organisms impinged. EPA also intended for facilities to have the flexibility to employ any system of technologies or combination of operational measures to address impingement mortality so long as the performance of the selected impingement reduction measures represented the best technology available for the site. The final rule includes an alternative reflecting these objectives.

In the broadest sense, facilities have a number of options for reducing impingement mortality. Some may choose to comply using an approach where a single technology achieves the level of compliance necessary. Others may choose an approach of employing multiple technologies or operational measures, including reducing the number of organisms that are impinged or susceptible to being impinged. The following are examples of approaches for which a facility might be able to take credit for impingement reduction under this alternative:

- Partial closed-cycle cooling
- Variable speed pumps
- Seasonal outages (including standard maintenance outages that are specifically scheduled to avoid a biologically sensitive period)
- Certain impingement technologies that reduce the number of organisms exposed to the intake structure (e.g., diversions, louvers, barrier nets)
- Intake location
- Behavioral technologies (e.g., light or sound barriers) [82]

In each case, the technology employed reduces the number of organisms that potentially are impinged, resulting in a reduction in the number of organisms actually impinged (i.e., a reduction in the rate of impingement). By virtue of reducing the actual impingement, mortality caused by impingement is no longer a consideration—an organism that is never impinged cannot be killed by the intake structure. Some technologies work to reduce the intake flow, thereby reducing the potential organisms exposed to the intake. Others work to divert organisms away from the screens, either through a physical exclusion or by being placed in a less biologically productive area. EPA concluded that it is appropriate to recognize these reductions in impingement as a step in achieving a BTA impingement mortality reduction performance at a particular site. As a result, EPA expects the reduction in impingement will be treated as an equivalent reduction in impingement mortality, and will therefore be considered by EPA or the State NPDES permitting authority in evaluating whether the chosen technologies and operational measures represent BTA performance under the site's conditions. For example, an intake that operates infrequently due to the infrequent operation of the electric generating unit(s) it serves (such as a peaking unit) may use a relatively small amount of water on an annual basis when compared to the design capacity of the intake structure. This facility may choose to comply with the impingement mortality standard at § 125.94(c)(6) by demonstrating to the Director that the facility operates at an annual intake flow that is less than or equal to 24 percent of its design intake flow on an annual basis. This level of flow reduction could achieve a level of performance equivalent to or better than the impingement mortality performance standard in § 125.94(c)(7), and therefore could be considered to be compliant with the requirements of today's final rule. This demonstration may include design data, several years of past operating data, and dispatch modeling. These operating conditions would then be incorporated into the NPDES permit.

A facility complying under this part, must submit a impingement technology performance optimization study, which must include the calculated percent impingement mortality reflecting optimized operation of the system of technologies, operational measures, and best management practices and all supporting calculations. Total system performance is the combination of impingement mortality performance reflected in all of the following which apply:

- Rate of impingement—The estimated reductions in rate of impingement must be based on a comparison of the system to a once-through cooling system with a traveling screen whose point of withdrawal from the surface water source is located at the shoreline of the source waterbody. For impoundments that include waters of the United States, the facility's rate of impingement must be measured at a location within the cooling water intake system that the Director deems appropriate.
- Impingement mortality—If the demonstration relies in part on a credit for reductions in impingement mortality already obtained at the facility, two years of biological data collection must be provided, demonstrating the level of impingement mortality the system is capable of achieving.
- Flow reduction—If the demonstration relies in part on flow reduction to reduce impingement, the data must include two years of intake flows, measured daily, as part of the demonstration. This must include documentation of how the flow reduction results in reduced impingement.

The permitting authorities would consider this information shown in the two-year impingement technology performance optimization study that must be submitted under this alternative. For example, at facilities choosing to comply by demonstrating that they are operating below 24 percent of their intake capacity, or that they are peaking units, the Director should use this study to establish operating conditions that ensure that the intake continues to operate below 24 percent of its intake capacity or continues to serve only peaking units and that these units are not later used as intermediate or baseload units. The operating conditions and parameters identified in the study will then be incorporated in the facility's permit conditions. EPA estimates that approximately 17 percent

[82] For example, anadromous clupieds such as alewife, blueback herring, and American shad have demonstrated avoidance behaviors when exposed to high frequency sound. Deployments of this technology at Entergy's FitzPatrick Nuclear Station on Lake Ontario have resulted in a reduction of over 90 percent in impingement of alewife. In this case, EPA expects the Director would determine that impingement requirements regarding alewife have been addressed by the acoustical deterrent. The Director could disallow such a technology if it were deemed to have a negative effect on threatened or endangered species whose habitat includes the facility's intake location.

of intake structures will choose this alternative.

f. Comply With the Numeric Impingement Mortality Performance Standard

Facilities complying with the BTA impingement mortality standard by achieving the numeric performance standard at § 125.94(c)(7) will perform monthly compliance monitoring to verify that the 12 month percent impingement mortality resulting from operation of its intake is below the standard established in today's final rule. (For more details on complying with the impingement requirements, see Section VIII.) EPA expects that, save for future technologies or innovations, few facilities will avail themselves of this option.

2. Entrainment Controls for Existing Units at Existing Facilities

The BTA entrainment standard for the final rule establishes a framework under which EPA or the State NPDES permitting authority must establish site-specific BTA entrainment requirements for each facility in the scope of today's rule. EPA considered promulgating no further controls to address entrainment mortality, and to rely instead only on the BTA impingement mortality controls, which would achieve up to a 34 percent reduction in total AEI. EPA did not select this option as the basis for national BTA because, in EPA's view, some facilities either are having a significant impact as a result of entrainment or might be able to do more to control entrainment at costs that are low relative to benefits. In addition, EPA's data on entrainment at facilities are not sufficient to allow the Agency to categorize facilities requiring no additional controls for entrainment. Thus, the final rule by requiring prescribed information in the permit application will provide the Director with adequate information for decision making. Requiring a structured site-specific analysis of candidate BTA technologies for entrainment control will allow the Director to determine where it is appropriate to require such controls. One outcome of the site-specific analysis could be that the Director would determine that no other technologies beyond impingement controls are required for BTA entrainment reductions, either because they are not feasible or because the social costs of additional control measures are not justified by the social benefits.

In the case of site-specific entrainment controls for facilities withdrawing greater than 125 mgd AIF, the final rule requires facilities to also develop and submit an Entrainment Characterization Study and related supporting information, as described in § 122.21(r)(9)–(13) of today's rule, for use by the Director in establishing site-specific BTA. For facilities above 125 mgd AIF that also meet the definition of closed-cycle recirculating systems at § 125.92(c), the Director may reduce or waive some or all of this information.

EPA considered simply requiring this information of all facilities above 125 mgd AIF without authorizing Directors to reduce or waive this information. However, EPA also recognizes that, in some instances, these same facilities have already minimized adverse environmental impacts significantly. In such cases, there may be limited value to the Director requiring a full benefit-cost analysis, or even obtaining the Entrainment Characterization Study at § 122.21(r)(9).

EPA also considered not requiring this information of any facilities above 125 mgd AIF meeting the definition at § 125.92(c). First, EPA noted that even though these facilities meet the definition of a closed-cycle recirculating system, they may still withdraw at least 125 mgd, and in some instances withdraw considerably more than 125 mgd. This is not an insubstantial volume of water withdrawn for cooling, and in the case of inland waters this withdrawal may comprise a large proportion of that source waterbody. In addition to withdrawing large volumes of water, EPA recognizes that some facilities, particularly those meeting the definition at § 125.92(c)(2), potentially withdraw water at a rate similar to a once-through facility not withdrawing from an impoundment, with the potential to cause adverse environmental impacts similar to those of once-through cooling. The Director may find the information in § 122.21(r)(9)–(13) to be useful in determining whether additional controls are warranted. In these instances, the Director may decide to require the Entrainment Characterization Study at § 122.21(r)(9) first, in order to determine if other studies in § 122.21(r)(10) to (13) are also warranted.

Facilities at or under the 125 mgd AIF threshold must still provide certain information under the permit application requirements at § 122.21(r). The Director may require additional information from these facilities including some or all of the studies at § 122.21(r)(9)–(13) if there is reasonable concern regarding entrainment impacts at the facility. Where an owner or operator of a facility intends to comply with the BTA standards for entrainment using a closed-cycle recirculating system as defined in § 125.92(c), the Director may reduce or waive some or all of this information.

Facilities with a closed-cycle recirculating system as defined at § 125.92(c)(2) would still submit the studies at § 122.21(r)(9)–(13) if they withdraw greater than 125 mgd AIF, and if the Director has not waived the requirements. These facilities have cooling systems that include impoundments of waters of the U.S. where the impoundment(s) was constructed prior to October 14, 2014 and lawfully created for the purpose of serving as part of the cooling water system. This purpose must be documented to the Director's satisfaction in the project purpose statement of any required Clean Water Act section 404 permit obtained to construct the impoundment. In the case of an impoundment whose construction pre-dated the CWA requirement to obtain a section 404 permit, where alternative permitting documents were required, the facility must document the project's purposes to the satisfaction of the Director by some other license or permit obtained to lawfully construct the impoundment for the purposes of a cooling water system. EPA notes that for impoundments constructed in uplands or not in waters of the United States, no documentation of a section 404 or other permit is required. EPA received comments that such impoundments should be treated as closed-cycle cooling and has agreed to make this change. The Director would still make the determination that make-up water withdraws have been minimized. Further, EPA's data shows that many facilities that utilize impoundments as part of their cooling water systems may actually use a combination of cooling water systems (for example, detailed survey responses showed eight facilities with an impoundment in addition to other IM technologies). The requirement that these facilities provide the Director with certain information will help ensure that the Director has adequate information upon which to base a decision for these impoundments as to whether these facilities have adequate controls already or should be taking additional measures to protect the relevant waterbody.

The Entrainment Characterization Study will include information already collected to meet existing § 122.21(r)(4) requirements. In addition, under the permit application requirements being added today at § 122.21(r)(5) to (13), the facility will submit certain additional site-specific information. This will include an engineering study of the technical feasibility and incremental costs of candidate entrainment mortality control technologies. The facility will also study, evaluate, and document the technical feasibility of technologies, at a minimum, including closed-cycle cooling, fine mesh screens with a mesh size of 2 mm or smaller, and water reuse or alternate sources; engineering cost estimates of all technologies considered; any outages, downtime, or other effects on revenue along with a discussion of all reasonable attempts to mitigate these cost factors; and a discussion of the magnitude of water quality and other benefits, both monetized and nonmonetized, of the candidate entrainment mortality reduction technologies evaluated. Finally, the information must include a discussion of the changes in non-water quality environmental impacts attributed to technologies and/or operational measures considered. The factors include, for example, increases and decreases in the following: Energy consumption, and air pollutant emissions including particulates and associated human health and global climate change impacts, water consumption, noise, safety (e.g., visibility of cooling tower plumes, icing), grid reliability, and facility reliability. For a thorough discussion of these study requirements, see Section VIII. The final rule also requires peer review of the Comprehensive Technical Feasibility and Cost Evaluation Study, Benefits Valuation Study, and Non-Water Quality and Other Impacts Assessment. Peer review of the Entrainment Characterization Study is not required. Note that the peer reviewed studies will rely on data gathered in the Entrainment Characterization Study. Peer reviewers will be selected in consultation with the Director, who can also consult with EPA and Federal, State, and Tribal fish and wildlife management agencies with responsibility for fish and wildlife potentially affected by the cooling water intake structure(s).

Under the final rule, EPA expects that the Director will review the candidate technologies for entrainment mortality control that, at a minimum, includes closed-cycle recirculating systems, fine-mesh screens with a mesh size of 2 mm or smaller, and water reuse or alternate sources. In the decision about what additional entrainment controls (if any) to require, the Director will consider all the facility-specific factors in § 125.98(f)(2) and described above. At a minimum, the Director must provide a discussion explaining how issues concerning air emissions or land availability, insofar as they relate to the feasibility of adoption of an entrainment technology, and remaining useful plant life, were addressed in the site-specific determination. Under the final rule, the Director must issue a written explanation for the basis of the BTA entrainment determination for each facility. The Director's decision must include a written explanation that, at a minimum, includes consideration of the following factors: (i) Numbers and types of organisms entrained; (ii) impact of changes in particulate emissions or other pollutants associated with entrainment technologies; (iii) land availability inasmuch as it relates to the feasibility of entrainment technology; (iv) remaining useful plant life; and (v) social costs and benefits, which may include qualitative, quantified and monetized categories. The Director may also base the proposed determination on several other factors, including thermal effects and water consumption.

In addition to the information required for development of impingement controls discussed above, the regulation also requires, in the case of facilities withdrawing greater than 125 mgd AIF, submission of certain other information for use in the site-specific entrainment determination of BTA. The final rule also adds the permit application requirements at § 122.21(r)(9)–(13) to require the facility to prepare several studies, including an Entrainment Characterization Study, that will fully characterize the extent of entrainment at the facility. (For more details about the study, see above). In addition, under the final rule, the facility will provide detailed information on the other factors relevant to the Director's site-specific BTA determination. These will include information concerning the technologies available for control of such entrainment, the costs of controls, the non-water quality environmental impacts of such controls, the monetized and nonmonetized benefits of such controls, and the presence of any threatened and endangered species. The final rule does not limit the Director's discretion to consider non-water quality impacts in determining whether further entrainment measures are justified. EPA encourages, and the CWA requires, the public to have a role in the permitting process. Interested members of the public may submit written comments on a draft permit during the 30 day public notice and comment period and request a public hearing on a draft permit. For permits that are issued by EPA instead of a state, additional opportunities for public involvement include comment, and in some cases, a public hearing on a permittee's State Water Quality Certification under section 401 of the CWA. (See 40 CFR 124.10, 124.11, 124.12(a) and 124.17(a).) Therefore, the final rule clearly affords the public a meaningful opportunity for participation in the site-specific decision making to help ensure the soundness of both the information and subsequent determinations.

H. Economic and Benefit Analysis for the Final Rule

1. Economic Justification for the Final Rule

Pursuant to the principles in E.O. 12866 and E.O. 13563, EPA has assessed costs and benefits for the final rule and has reasonably determined that the benefits of the rule justify the costs. EPA has estimated the social cost of this rule to be $275 million annually. For more information on EPA's analysis of the rule's costs, see Section IX.

As described in more detail below in Section X, significant benefits are associated with the rule. These benefits include the annual reduction in impingement mortality of 652 million age-one equivalents for existing units. There are, in addition, other important benefits, many of which EPA cannot quantify. These benefits include effects on many shellfish species and nonuse values associated with the vast majority of fish and shellfish. The rule also requires establishing site-specific entrainment controls through a process in which specific environmental conditions and the localized benefits of entrainment reductions will be assessed along with the costs of controls. The information generated in the required studies will enhance the transparency of decision making and provide an opportunity for meaningful public participation, ensuring that decision making is based on the best available data. Overall, these requirements and subsequent Director actions under this rule will foster protection and restoration of healthy aquatic ecosystems that have important commercial, recreational, aesthetic and cultural values to their surrounding communities. Many of the benefits that will result from the rule are not monetized or quantified, and as a result the Agency's monetized benefits analysis underestimates the totality of the rule's benefits. On the basis of the record, EPA has determined that the impingement mortality and entrainment controls will result in benefits that justify the costs of the rule.

EPA also notes that it was able to generate only a partial estimate of benefits for today's rule. In particular, EPA's analysis does not fully quantify or monetize certain potentially important categories of benefits, such as existence values for threatened and endangered species, secondary and tertiary ecosystem impacts, benthic community impacts, shellfish impacts and the impacts arising from reductions in thermal discharges that would be associated with closed-cycle cooling. Changes in fish assemblages due to impingement, entrainment and thermal effects are also not fully valued. These categories of benefits which are not fully valued are often referred to as nonuse benefits—i.e., benefits that people derive apart from using an affected resource, such as fishing. For example, nonuse benefits would include the value that individuals place on knowing that an aquatic ecosystem is healthy. EPA conducted a nonuse benefits transfer was based on a species that represents less than one percent of adverse environmental impacts. EPA developed and implemented an original stated preference survey to estimate total values (use plus nonuse values) for aquatic resource improvements under 316(b) regulatory options. EPA decided not to employ the survey results for purposes of decision-making and EPA has not accounted for values estimated from the survey in the quantitative comparison of costs and benefits. It is also important to note that EPA's stated preference survey was designed to estimate respondents' willingness to pay for changes in the health of fish populations and aquatic ecosystems and to be statistically representative at large (regional and national) scales; the results were not specifically designed to be statistically representative at the facility level for the assessment of benefits for individual site-level permitting decisions.

As noted at the outset, it is not always the case that private decision making regarding withdrawals of cooling water takes into account society's preferences for fish protection, nor are there market transaction opportunities for individuals to express their willing to pay for fish protection. Thus, despite the limited information on monetized social benefits, EPA has concluded that the benefits of today's rule justify the costs of today's rule.

2. Comparison of the Other Options

As discussed above, EPA considered three other primary options before selecting today's rule. See Section VI.F Other Options Considered for more detailed explanation of each option. Exhibit VI–1 illustrates a comparison of the total annualized social costs and benefits.

EXHIBIT VI–1—COMPARISON OF THE PRIMARY OPTIONS FOR 316(b)

[$2011 Millions at 2013, 3% discount rate]

Option	Total annualized social cost	Monetized benefits
Proposal Option 4	$251.8	$31.0
Final Rule	274.9	32.8
Proposal Option 2	3643.2	−1542.6

I. Site-Specific Consideration of Entrainment Controls

As described above, EPA is not promulgating uniform national requirements for entrainment for existing facilities. Instead, EPA is setting standards for entrainment that include a framework by which a facility will be subject to a site-specific determination by EPA or a State NPDES permitting authority of appropriate BTA requirements for entrainment. This section describes the process for determining section 316(b) requirements for an individual facility under the national BTA standard for entrainment. It describes the elements that the Director must consider in the permitting decision and how costs and benefits may be considered in such an evaluation.

1. Implementation of a Site-Specific Evaluation of Entrainment for Existing Facilities

The final rule requires a site-specific determination of BTA entrainment conditions in individual permits and prescribes the requirements for that permitting proceeding. The final rule includes permit application requirements for facilities with a cooling water intake structure. These requirements are designed to elicit the information the Director needs to determine the best technology for reducing entrainment for a particular facility, including information pertinent to an assessment of whether the benefits justify the costs of any particular control measures under consideration.

Today's final rule is a modification of the proposed approach of a site-specific BTA entrainment determination. It will result in one of two outcomes at any facility:

1. Determination that the facility must install additional control measures that reduce entrainment beyond that achieved by the currently installed equipment. These may include closed-cycle cooling and/or other technologies.

2. Determination that the facility's current, existing technology for entrainment achieves the entrainment BTA requirements under the national BTA standard.

Thus, EPA expects that, under this approach, there will be additional entrainment controls for some facilities and none for others. Even where the Director's determination requires no additional control measures, the Director may conclude the permit should include conditions that specify proper operation and maintenance of the installed technology.

EPA notes that in a number of areas of the country (California, Delaware, New York, and New England; see, for example, DCNs 10–6963 and 10–6841, and EPA Region I's Brayton Point), permitting authorities have already required or are considering requiring existing facilities to install or retrofit to closed-cycle cooling systems. These facilities are still subject to today's rule but the existing requirements have been taken into account in costing.

For facilities that withdraw more than 125 mgd, the rule generally requires that the facility conduct an entrainment study as part of its permit application. The study will indicate, at a minimum, the specific entrainment data collection methods, taxonomic identification to the lowest taxon possible, latent mortality identification, documentation of all methods, and quality assurance/quality control procedures for sampling and data analysis appropriate for a quantitative survey. Peer reviewers must be selected in consultation with the Director, who may consult with EPA and Federal, State, and Tribal fish and wildlife management agencies with responsibility for fish and wildlife potentially affected by the cooling water intake structure. Data from the entrainment study is important to provide corroboration of any through-facility entrainment survival study results in § 122.21(r)(7) or from any other studies conducted.

The final rule also requires the permit application to include the following information as part of the entrainment study (which refers to the requirements at § 122.21(r)(9) through (13), as opposed to the Entrainment Characterization Study at § 122.21(r)(9)). For a thorough discussion of these study requirements, see Section VIII:

• An engineering study of the technical feasibility and estimated costs of all candidate entrainment control technologies, including closed-cycle cooling, fine-mesh screens with a mesh size of 2 mm or smaller, and water reuse or alternative sources;

• A discussion of any outages, downtime, or other effects on revenue along with a discussion of all reasonable attempts to mitigate these cost factors

• A discussion of the magnitude of water quality benefits, whether qualitative, quantitative or monetized, of the candidate entrainment reduction technologies evaluated; thermal discharges; and

• A discussion of the changes in non-water quality environmental impacts and other factors attributed to technologies and/or operational measures considered, including, for example, increases and decreases in the following: Energy consumption; air pollutant emissions including particulates and their health and environmental impacts; noise; safety (e.g., visibility of cooling tower plumes, icing); electric grid reliability, and facility reliability.

The permit application will provide the Director with information about options for entrainment reductions at the site and other possible avenues for addressing any adverse effects from entrainment. The purpose of the entrainment study and other permit application materials is to assist the Director in better understanding the effect of entrainment on species in the waterbody from which cooling water is withdrawn. More specifically, the entrainment study will identify species that might be entrained, and estimate their baseline entrainment rates given current entrainment controls. Moreover, the entrainment study will include information about the aquatic ecosystem effects of entrainment of species, and any threatened and endangered species whose range of habitat includes waters where the facility's intake is located. An understanding of the potential ecosystem consequences of entrainment for species will help inform Director decisions about additional information required in the permit application, or permit requirements for any possible additional technologies and management practices. EPA will endeavor to identify high-quality examples of entrainment studies as they are completed, and post them to its Web site for this rule as a resource for study preparation.

EPA's benefits estimates were based on an extrapolation of available literature on impingement and entrainment studies; the specific Entrainment Characterization Study prepared by a facility could lead to a different estimate of impingement and entrainment for that facility relative to its share of EPA's estimate in the analysis supporting this rule and in the record.

Following the Director's review of this information, the Director must determine what BTA entrainment requirement to propose and explain in writing the basis for the draft permit. The draft permit will then be available for comment from the interested public under the Director's normal permitting process.

2. Site-Specific Consideration of Cost and Benefits

In establishing requirements under section 316(b) of the CWA, the Supreme Court in *Entergy* made clear that one factor that EPA may, but is not required, to consider is the costs and benefits associated with various control options. That is, in setting standards, EPA may consider the benefits derived from reductions in the adverse environmental impacts associated with cooling water intake structures and the costs of achieving the reductions. As previously explained, following E.O. 13563, EPA has determined that the benefits of the final rule justify its costs. In addition, EPA has explained (in Section II.C above) why consideration of quantitative and qualitative social costs and benefits may be appropriate in the site-specific determinations when establishing entrainment controls.

In the site-specific proceeding, the Director must consider, among other factors, monetized, quantified and qualitative social benefits and social costs of available entrainment controls, including ecological benefits and benefits to any threatened or endangered species. The Director may be able to reject otherwise available entrainment controls if the costs of the controls are not justified by their associated benefits (taking into account monetized, quantified, and qualitative benefits), and the other factors discussed in the final rule.

In making the site-specific entrainment BTA requirements determination, the final rule requires that the Director consider the information submitted under § 122.21(r) with the section 316(b) permit application. Further, in the case of the larger withdrawing cooling water intake structures (125 mgd AIF or greater), the rule requires submission of additional information including, studies on entrainment at the facility, the costs and feasibility of control options, and information on the benefits of entrainment controls. In evaluating benefits, the Director should not ignore benefits that cannot be monetized or quantified or consider only the impingement and entrainment reductions that can be counted. To result in appropriate decisions from society's standpoint, the assessment of benefits must take into account all benefits, including categories such as recreational, commercial, and other use benefits; benefits associated with reduced thermal discharges; reduced losses to threatened and endangered species; altered food webs; benefits accruing nonlocally due to migration of fish; nutrient cycling effects; and other nonuse benefits. Merely because it is difficult to put a price tag on those benefits does not mean that they are not valuable and should not be included at least qualitatively in any assessment. The rule does not require the Director to require a facility owner or operator to conduct or submit a willingness-to-pay survey to assess benefits. Further, the rule does not limit the Director's discretion to consider non-water quality impacts in determining whether further entrainment measures are justified. When some benefits are not monetized, the requirement to consider costs and benefits in today's rule does not mean the Director should base decisions solely on the monetized benefits and costs, ignoring the non-monetized benefits. Instead, the Director should consider the costs and what the magnitude of the non-monetized benefits would have to be in order to justify the costs.

An aggregate evaluation of benefits (even if accurate) would not account for the variations in benefits from location to location. On the basis of available information, EPA's analysis of benefits relied on extrapolating data from existing impingement and entrainment characterization studies to all facilities in the same region on a flow-weighted basis. Differences in species, life stages, and biological abundance across intake locations (even within a region) could lead to very different results for a site-specific analysis of a facility as compared to that facility's share of national costs and benefits, even if the national results are, on average, accurate. A national assessment tends to mask variations in benefits and costs from different geographical locations for different water bodies. For example:

• Some fish species at coastal facilities have biological spawning attributes that differ from those at other locations.

• The proportion of the receiving water withdrawn for cooling could also vary among sites.

• The values that communities place on their resources could vary from site to site.

• One ecological environment might experience large masses of hardier eggs and larvae subject to potential entrainment; another will have fewer but less hardy eggs and larvae susceptible to entrainment. Without detailed study information, it's difficult to ascertain which ecological environment faces the greater adverse environmental impact from a similar cooling water intake.

The resulting differences in the value of reduced entrainment—which could be dramatic for some sites—necessarily disappear in a national aggregation of results. The Agency has decided that this masking of variation in benefits further supports EPA's decision to require consideration of the site-specific benefits of entrainment control technologies in the site-specific process to establish entrainment controls.

The Director must then explain the basis for rejecting an available technology not selected for entrainment control in light of the submissions after consideration of the three factors that supported EPA's determination not to establish a uniform national entrainment standard based on closed-cycle cooling. The Director also must base the determination about BTA controls on the number and types of organisms entrained, including Federally-listed, threatened and endangered species and designated critical habitat (e.g., prey base) as well as consideration of the site-specific social costs and benefits (monetized and nonmonetized) of the various control technologies considered for the facilities.

As noted, the Director may reject an otherwise available entrainment technology as the BTA requirement (or not require any additional BTA controls) if the social costs of the controls are not justified by the social benefits (monetized and nonmonetized). EPA decided to adopt this approach in determining site-specific entrainment controls because it is permissible under *Entergy,* under E.O. 13563, and consistent with the more than 30-year history of section 316(b) permitting decisions.

This history illustrates the role that cost/benefit considerations have played. As early as 1977, EPA in a permitting decision and a General Counsel opinion explained that, while section 316(b) does not require a formal cost-benefit analysis, the relationship of costs and benefits may be considered in 316(b) decision making. *In re Pub. Serv. Co. of N.H. (Seabrook Station, Units 1 and 2),* No. 76–7, 1977 WL 22370 (June 10, 1977), remanded on other grounds, 572 F.2d 872 (1st Cir. 1978); accord *In re Central Hudson Gas & Elec. Corp., Op. EPA Gen. Counsel,* NPDES No. 63, 1977 WL 28250, at *8 (July 29, 1977). In the more than 30 years since, EPA and State permitting authorities have considered the relationship between costs and benefits to some extent in making individual permitting decisions. See, for example, *In re Pub. Serv. Co. of N.H. (Seabrook Station, Units 1 and 2),* No. 76–7, 1978 WL 21140 (E.P.A. Aug. 4, 1978), aff'd, *Seacoast Anti-Pollution League* v. *Costle,* 597 F.3d 306, 311 (1st Cir. 1979).

Because E.O. 13563 directs agencies to propose and adopt rules only upon a reasoned determination that the benefits justify the costs, EPA is allowing this consideration to be applied at the permit level. This approach is consistent with the historical application of section 316(b) requirements and will allow for a full assessment in permit decisions of both qualitative and quantitative benefits and costs. As designed, EPA's requirement for the establishment of site-specific BTA entrainment requirements strikes an appropriate balance between environmental improvements and costs, allowing the Director to consider all the relevant factors on a site-specific basis and determine BTA on the basis of those factors.

After considering the factors relevant to a site, the Director must establish appropriate entrainment controls at those facilities. The Director must review available control technology and may reject otherwise available entrainment controls as BTA if the social costs of the controls are not justified by their social benefits (taking into account both quantified and non-quantified benefits) or if the Director concludes that there are other unacceptably adverse factors that cannot be mitigated. As designed, EPA's national BTA standard for establishing site-specific BTA entrainment requirements strikes an appropriate balance between environmental improvements and costs by selectively requiring closed-cycle cooling or other entrainment technologies at some facilities, without requiring the same technologies at all facilities.

3. Potential Cost for Site-Specific Entrainment Controls

For the proposed rule, EPA analyzed possible additional costs associated with reductions in entrainment mortality that might result from the Directors' determinations of site-specific BTA requirements. Because this process will play out over a number of years as Directors consider waterbody-specific data, local impacts, and public comment, and weigh land availability, air quality impacts, and remaining useful life, those estimates of the costs of site-specific determinations are highly speculative. EPA is not presenting specific cost estimates today for prospective entrainment requirements because we do not have in hand the robust data that will be generated for individual site-specific settings as required under the national BTA standard for entrainment. Without that refined information on a site-specific basis, EPA has no ability to predict Director decision-making and therefore, the Agency is not estimating costs associated with the ultimate entrainment requirements. Similarly and for the same reasons, EPA did not estimate costs associated with requirements at §§ 125.94(g), 125.94(c)(8) or 125.94(c)(9).

EPA estimates that the most effective technology for reducing entrainment, closed-cycle cooling, is not available to at least one quarter of all facilities because of geographic constraints, air permitting restrictions in a nonattainment area and remaining useful life of the facility. EPA has limited information on which facilities these are, despite the certainty that these availability concerns are real and significant. In addition, EPA does not have in hand the site-specific data that will be generated as a result of today's rule. If EPA had this data, it would be possible to estimate the costs and benefits ultimately associated with the Directors' site-specific determinations under the national BTA standard for entrainment. The hypothetical costs generated at proposal were reported in an attempt to signal that EPA neither expects that zero facilities would be subject to closed-cycle cooling as a result of the site-specific BTA process for entrainment, nor that all facilities at which these technologies are feasible would be subject to closed-cycle cooling requirements. Without the site-specific information, there is significant uncertainty around any estimates EPA could generate of these costs (including those reported at proposal) and benefits.

VII. Response to Major Comments on the Proposed Rule and Notices of Data Availability (NODAs)

Over 1,100 organizations and individuals submitted comments on a range of issues in the proposed rule, including over an additional 62,000 letters from individuals associated with mass letter writing campaigns. An additional nearly 250 comments were received on the two NODAs. Responses to all comments, including those summarized here, are in the Response to Comments document in the official public docket (see DCN 12–0004). To facilitate a more comprehensive response and to simplify the task of discussing EPA's rationale for promulgating the final rule, EPA is responding to these public comments in essay form. Each topic area discussed in the comment letters has been addressed in one of the comprehensive essay responses. The major comments received and EPA's responses are summarized in this section.

A. Scope and Applicability

1. Source of Water—Impoundments

Many commenters expressed concern that the proposed rules do not adequately address the unique water bodies resulting from the many man-made reservoirs specifically designed and constructed as cooling water impoundments (referred to as cooling ponds in the proposed rule). Commenters expressed confusion regarding the applicability of the proposed regulations because impoundments have both intakes from the impoundments and intakes that supply water to the impoundment. Many requested that EPA clarify that man-made impoundments, built to supply water for power plants, do not constitute water of the United States for purposes of implementing the rule or that they should be classified as meeting the definition of closed-cycle cooling.

Response: As discussed in Section I, facilities that withdraw cooling water from impoundments that are waters of the United States and that otherwise meet the criteria for coverage (including the requirement that the facility has or will be required to obtain an NPDES permit) are subject to today's rule. Revisions to the definition of waters of the U.S. are outside the scope of this rulemaking. However, today's regulatory definition of closed-cycle recirculating systems specifies that such a system may include impoundments of waters of the U.S. where the impoundment was constructed prior to today's final rule. To meet the rule definition for closed-cycle recirculating system, this impoundment must have been lawfully created for the purpose of serving as part of the cooling water system as documented in the project purpose statement for the Clean Water Act section 404 permit obtained to construct the impoundment. In the case of an impoundment whose construction pre-dates the CWA requirement to obtain a section 404 permit, EPA expects documentation of the project's purpose to be demonstrated to the satisfaction of the Director. This documentation could be some other license or permit obtained to lawfully construct the impoundment for the purposes of a cooling water system, or other such evidence as the Director finds necessary.

The definition of closed-cycle recirculating system at § 125.92(c)(1) of today's rule also specifies that impoundments that are not waters of the United States but withdraw make-up water from waters of the U.S. meet the definition of a closed-cycle recirculating system, if make-up withdrawals have been minimized. These impoundments are constructed in uplands, and are not required to obtain a 404 permit. Thus, these impoundments do not need to provide documentation of the project's purpose.

2. New Units

In the proposal, EPA defined new units as newly built units added to increase capacity at the facility. The definition did not include any rebuilt, repowered or replacement unit, including any units where the generation capacity of the new unit is equal to or greater than the unit it replaces. Many industry stakeholders agreed that the definition of new units should not include repowered existing units. Others thought that new units should be treated similarly to existing units with entrainment standards applied on a site-specific basis and that the nine proposed factors should also be applied to entrainment decisions for new units. Environmental organizations argued that EPA should set a deadline by which all existing facilities must comply with the new unit standards and that EPA's exclusion of repowered/rebuilt facilities created a loophole through which existing facilities could perpetually operate as an existing unit, even after replacing all of the generating equipment. Many of the comments had several elements in common:

- Requirements should be flexible enough to address sites where meeting the requirements is not technically feasible (e.g., limited land availability).
- EPA needs to provide greater clarity regarding how new unit standards apply to manufacturing facilities.
- The DIF is a more appropriate parameter for determining compliance because AIF cannot be determined until after the system is built, and baseline AIF would require assumptions about as-yet undetermined operational factors.
- It is unclear how the new unit requirements will be applied to manufacturing units, and the requirements do not appear to consider the circumstance where a new unit is constructed at an existing manufacturing facility where construction of the new unit does not require any modifications to the existing intake structure.
- Some commenters have noted that the new unit provisions are a departure from previous determinations and are unclear. They argue that they have not had adequate opportunity to comment on this issue and request EPA re-propose new unit requirements if it wants to continue with this initiative.

Response: EPA's definition of a ''new unit'' for the final rule can be found at § 125.92(u). New units includes the addition of a stand-alone unit that is constructed at an existing facility. The rule definition makes it clear that the new unit may be for the same general industrial activity as the existing facility. Because the requirements are much like the Phase I requirements for new facilities the costs for installing controls at new units are similar to the costs imposed on new facilities. The cooling water withdraws made by the rest of the existing facility are subject to the requirements at 40 CFR 125.94(c) and (d).

With respect to impingement mortality and entrainment, the final rule requires, at § 125.94(e)(1), that new units achieve flows commensurate with that of a closed-cycle recirculating system. As with the new facility Phase I rule, the new unit may choose to meet an alternative requirement at 40 CFR 125.94(e)(2) and demonstrate to the Director that the technologies and operational measures employed will reduce the level of adverse environmental impact from any cooling water intake structure used to supply cooling water to the new unit to a comparable level to that which would be achieved upon implementing closed-cycle recirculating for that new unit. This includes a demonstration showing that the entrainment reduction is equivalent to 90 percent or greater of the reduction that could be achieved through implementing a closed-cycle recirculating system. This demonstration must also include a showing that the impacts to fish and shellfish, including important forage and predator species, within the watershed will be comparable to those which would result if the facility were to implement a closed-cycle recirculating system.

Facilities may choose to install a closed-cycle recirculating system, and EPA has observed that many new units are selecting closed-cycle recirculating systems on their own, particularly for combined cycle and natural gas for reasons unrelated to 316(b) (such as water availability). In these cases, benefits related to reductions in IM&E would be expected to occur.

Finally, for new units at existing facilities, the Director may establish alternative requirements if the data specific to the facility indicate that compliance with the requirements of paragraphs (e)(1) or (2) of § 125.94 for each new unit would result in compliance costs wholly out of proportion to the costs EPA considered in establishing the requirements at issue, or would result in significant adverse impacts on local air quality, significant adverse impacts on local water resources other than impingement or entrainment, or significant adverse impacts on local energy markets. This provision is identical to that provided in the Phase I new facility rule.

B. Proposed Amendments Related to Phase I Rule

Commenters suggested that restoration be allowed in a range of situations, including where a nuisance species is a problem that will get worse with the use of cooling water intake structure technology, where affected species are not species of concern in man-made lakes, and to reduce the cost of meeting 316(b) requirements (i.e., offset losses).

Response: The Second Circuit found that EPA exceeded its authority by allowing facilities subject to CWA section 316(b) to comply with section 316(b) through restoration measures and, thus, EPA has deleted these provisions from the regulations at §§ 125.84 and 125.86 to make the rule consistent with the court decisions.

C. Environmental Impact Associated With Cooling Water Intake Structures

Many commenters expressed concern that limited scientific evidence exists that measureable aquatic population or community effects occur as a result of cooling water withdrawals and that impingement mortality and entrainment mortality requirements should not apply unless adverse environmental impacts are demonstrated. They also noted that not all environmental impacts are adverse. For example, removal of invasive species or quickly reproducing species might not be harmful.

Response: EPA disagrees. The evidence shows that the total number of aquatic organisms lost annually is in the hundreds of billions, or is 1.9 billion on an age-one equivalent basis. Additional data provided in comments shows aquatic organisms are lost through impingement and entrainment by all types of cooling water intake structures. The data demonstrates that the effects of cooling water intake structures on the aquatic environment are significant and widespread. In addition, there is documented evidence of population level effects of cooling water intakes for certain species in certain instances. See, for example, 69 FR 41587, July 9, 2004 for a discussion from the 2004 Phase II rule. Also, Bayshore, Indian River and Indian Point are discussed in the BA for the final rule.

D. EPA's Approach to BTA

1. Relationship of Costs and Benefits

Many commenters expressed concern that the proposed rule's costs significantly outweigh the benefits and that studies, technology modifications, monitoring, and reporting should not be required if costs exceed benefits.

Response: While the rule costs exceed the monetized benefits as presented, EPA has concluded that the costs do not outweigh total benefits when both monetized and nonmonetized benefits are considered. EPA notes that the monetized benefits are only a subset of all benefits. In the absence of complete estimates of nonuse benefits, EPA estimated partial nonuse benefits for the final rule using the benefits transfer approach from proposal. This approach is still a partial estimate, because the nonuse benefits transfer was based on a species that represents less than one percent of adverse environmental impacts. With respect to entrainment, the rule authorizes the Director to consider costs versus benefits on a site-specific basis. With respect to impingement mortality, the rule provides seven compliance alternatives based on a set of widely used, demonstrated, proven technologies, many of which have been in use for decades and whose efficacy is well supported in EPA's record.

2. Site-Specific Approach

Many commenters agreed with EPA's site-specific approach for entrainment mortality requirements but argued that the same approach should also be applied to impingement mortality requirements. State agencies and environment organizations are concerned that the site-specific entrainment determinations will create additional administrative burdens on already overextended permitting authorities which could exacerbate permit backlogs.

Response: EPA does not agree that impingement mortality is best addressed by the same approach adopted for entrainment. This is because EPA has been able to identify low-cost technologies that are available, feasible and demonstrated for impingement mortality nationally. EPA has not been able to identify an available, feasible and demonstrated technology nationally for entrainment, and therefore has adopted as its national BTA entrainment standard a structured process for determining on a site-specific basis what entrainment controls are the best technology available at a particular facility. EPA agrees that site-specific entrainment has potential to create additional burdens for states, but EPA has tried to limit this burden by simplifying its information collection requirements from those at proposal. EPA has streamlined the information collection requirements so that information necessary for the Director to make a BTA determination is submitted by the permittee in the permit application early in the process, thus minimizing the number of transactions between permittee and the Director.

E. BTA Performance Standards

1. Impingement Standards

EPA received a substantial number of comments on how the final rule should address impingement mortality. EPA proposed an impingement mortality standard based on the performance of modified traveling screens with fish handling and return that required achievement of a numeric IM performance standard. As an alternative EPA proposed that a facility could demonstrate that either the design intake velocity or the actual intake velocity at its operation was less than 0.5 fps. Most of the commenters, including members of the U.S. Congress, state and local elected officials, and industry stakeholders, requested additional flexibility in complying with the impingement mortality standards. While the proposal would not specifically require the use of modified traveling screens with a fish handling and return system to meet the impingement mortality standards, some commenters interpreted the proposed rule as requiring this. EPA proposed impingement mortality standards that were expressed as a monthly average and a 12-month average. EPA recognizes, however, that some regulated entities might find a technology-based compliance option, rather than a performance-based approach, more attractive. Such an approach, particularly the specification of pre-approved technologies, could offer higher regulatory certainty, easier demonstration of compliance, and might offer a less expensive alternative because of reduced monitoring requirements associated with pre-approved technologies. Some commenters viewed the proposed impingement mortality standard as overly stringent and requested that EPA establish alternative impingement mortality standards, including site-specific impingement mortality requirements similar to those proposed for entrainment. Other commenters provided data pertaining to the performance of technologies, including modified traveling screens used as the basis for the impingement mortality performance standard. Several industry stakeholders stated that, despite EPA's best intentions, the proposed rule applied a one-size-fits-all approach for impingement mortality. While all the suggested changes to the proposal seek to provide additional flexibility through a variety of approaches, most of the comments had several elements in common:

- Defining modified traveling screens as a pre-approved technology or otherwise streamlining the NPDES process for facilities using the candidate technology on which BTA is based. Thus, EPA would designate certain technologies or certain conditions as complying with the impingement requirement.
- Providing a mechanism to identify other technologies that perform comparably to modified traveling screens.
- Modifying the proposal so that facilities that have already reduced the rate of impingement could obtain credit toward the impingement mortality standard.
- Developing a more tailored approach to protecting shellfish.
- Creating alternatives for facilities with very low (de minimis) impingement levels or mortality rates.
- Providing additional clarity on species of concern as it pertains to demonstrating compliance with the numeric impingement mortality performance standard.
- Reevaluating the impingement mortality numerical performance standards.

In addition, as noted above, EPA also received a number of comments suggesting that it adopt a site-specific approach to reducing impingement mortality similar to the proposed approach for addressing entrainment, rather than uniform national requirements for impingement mortality and a site-specific approach for entrainment only.

Many commenters expressed concern that the entrapment requirements were not well defined and would require costly technologies that are not considered in EPA's cost estimates and could be difficult to comply with, particularly where cooling systems employ impoundments or basins downstream of the initial intake structure.

Response: See the earlier discussion concerning how EPA determined the numeric impingement mortality performance standard. Additionally, see earlier discussion for an explanation of how EPA revised the impingement mortality standard to provide seven alternatives for compliance.

EPA agrees that specific entrapment requirements are not necessary and requirements for facilities to deploy technologies to avoid entrapment have been deleted from the final rule. However, a facility that entraps fish must count the entrapped organisms as impingement mortality.

2. Entrainment Standards

A substantial number of commenters supported EPA's site-specific approach for entrainment standards. Suggested revisions to the approach included the following:

- EPA should recognize the value of waterbody-based requirements, including withdrawals on lakes/reservoirs and less than 5 percent of rivers as not requiring entrainment mortality.
- Units with a low capacity utilization should be exempt from entrainment mortality.
- Facilities with AIF of less than 125 mgd should be presumed as entrainment mortality compliant.
- EPA should consider entrainment survival.

Response: With respect to waterbody-based requirements and capacity utilization thresholds, EPA disagrees with commenters suggestions. There is no fundamental difference in technological performance based on waterbody so there is no need to subcategorize based on waterbody. EPA found that low CUR facilities are generally peaking plants that operate at full capacity for portions of days during a few months or less. Further, EPA found that some sites continue to withdraw water through their cooling water intake structure even when no power is being generated. If that period of cooling water intake operation corresponds with times when spawning is occurring, those facilities could have significant impacts from impingement and entrainment. Therefore, simply being a low CUR unit does not imply no adverse environmental impacts. Instead, EPA found that low CUR should be looked at more closely on an individual unit basis. EPA has included a provision in the final rule that states where a generating unit has an annual average capacity utilization rate of less than 8 percent averaged over a 24-month block contiguous period, the owner or operator may request that the Director establish less stringent standards for IM. With respect to facilities below 125 AIF being considered entrainment compliant, EPA disagrees with the comment since any facility at any flow may have an adverse environmental impact. With regard to entrainment survival, EPA does allow for consideration of entrainment survival. The monitoring requirements for entrainment for new units at § 125.96(d)(3) states that mortality after passing the cooling water intake structure must be counted as 100 percent mortality unless you have demonstrated to the approval of the Director that the mortality for each species is less than 100 percent.

3. Closed-Cycle Cooling

Both industrial stakeholders and many state agencies endorsed an approach that deems facilities with closed-cycle cooling to be in compliance with the BTA impingement mortality standard, and eligible for reduced monitoring and reporting requirements. Most industrial stakeholders agreed with the EPA decision that closed-cycle cooling should not be imposed as a national BTA standard. They argue that although closed-cycle cooling might be available and achievable at many facilities, requiring closed-cycle cooling nationally has numerous drawbacks including the following:

- Requirements for closed-cycle flow reduction do not take into consideration the site-specific limitations at some facilities (e.g., blowdown water quality, scale, fouling problems).
- Cooling towers would result in significant adverse impacts from fine particulates, carbon dioxide emissions, evaporative water loss, and other issues.

Commenters expressed concern that the proposed definition of a closed-cycle recirculating system is far more restrictive than the definition used in the Phase I rule. It includes only systems that withdraw make-up flow intermittently, are designed to operate above minimum COC, reduce flow by a specified percentage (depending on whether salt or fresh water), and did not include impoundments that are waters of the United States. Some commenters stated that while they might have been effectively operating as closed-cycle units for many years, they have concerns with their ability to comply with the definition in the proposal, particularly with respect to the specified COC.

Response: EPA agrees that facilities employing a closed-cycle recirculating system for entrainment should also be deemed in compliance with the impingement mortality standard, as long as the system is properly operated. While a closed-cycle recirculating system is the most effective technology for reducing entrainment, EPA has not established BTA based on closed-cycle cooling because EPA concluded it was not BTA, for the reasons specified in Section VI. Regarding the definition of closed-cycle cooling, EPA identified two parameters that demonstrate proper operation: Flow reduction and cycles of concentration. To provide flexibility, EPA has removed the numeric levels of the metrics as threshold, while retaining the minimized makeup flows aspect of the definition. Therefore while the definition in this final rule does not establish fixed requirements in terms of COC and comparable percentage flow reduction to qualify as a closed-cycle recirculating system, the rule provides that a closed-cycle recirculating system ''generally'' will achieve the specified benchmarks that characterize a properly operating closed-cycle cooling system. EPA further recognizes that certain unavoidable circumstances could exist where the specified COC or percent reduction values might not be achievable. Such site-specific circumstances could include situations where water quality-based discharge limits might limit the concentration of a pollutant that is not readily treatable in the cooling tower blowdown or situations where the source water quality could lead to unavoidable problems concerning scale formation, solids buildup, corrosion, or media fouling. If a facility can demonstrate that these occurrences are unavoidable, under the definition in the final rule, the Director may determine that such a facility is a closed-cycle recirculating system, taking into account the site-specific circumstances. In addition, EPA has explained how the conditions added to the existing facilities definition do not in effect make it more stringent than the Phase I definition of closed-cycle recirculating systems. The auxiliary electricity a facility uses to run the fans in a closed-cycle system is electricity the facility can't sell. The opportunity cost to the facility of using that electricity to run the fans is the forgone revenue they would have been able to earn if they had run their cooling water system in once-through mode. The forgone revenue provides the incentive for a facility to run its closed-cycle system in once-through mode, rather than in closed-cycle mode. Thus, EPA adjusted the definition of a closed-cycle recirculating system to be appropriate for retrofit situations.

F. Implementation

Many commenters expressed concern that the compliance timeline for impingement mortality and entrainment requirements should be synchronized to prevent a facility from having to install technology to comply with impingement mortality requirements and then later be required to install entrainment mortality technology.

Response: To address this concern, EPA revised the impingement mortality compliance requirements to provide that after issuance of a final permit establishing the entrainment requirements under § 125.94 (d), the owner or operator of an existing facility must comply with the impingement mortality standard in paragraph § 125.94(c) as soon as practicable. When the Director establishes a compliance schedule under § 125.94(d), the schedule must provide for compliance as soon as practicable. Thus, EPA has synchronized decision making about technology requirements, avoiding situations where investments in IM controls would later be rendered obsolete by entrainment control requirements.

G. Costs

1. Impingement Mortality Technology Costs

Commenters expressed concern about the approach for technology assignments used to estimate compliance with the impingement mortality standards and generally asserted that costs were underestimated. These concerns included the following:

- The EPA incorrectly assumed traveling screens were an available technology at most facilities.
- EPA underestimated the costs of modified traveling screens.
- EPA underestimated the difficulty and costs of installing fish returns.

Response: EPA disagrees that traveling screens are not an available technology at most facilities; survey data provided by industry shows that 93 percent of generators and 73 percent of manufacturers already have screens. EPA agrees that some facilities may not be able to readily upgrade their screens to modified traveling screens with fish return, but that the vast majority can.

EPA has updated the estimated costs of the rule to reflect the difficulty of installing fish return and adjusted the cost of modified traveling screens to reflect most recently available vendor data. Specifically, EPA reviewed the cost methodology and made a number of revisions including the following:

- EPA revised the technology assignment such that only those model intakes that have existing traveling screens are assigned modified traveling screen costs.
- EPA increased the estimated capital costs for modified traveling screens by 20 percent.
- EPA increased the estimated capital costs of fish returns and provided for an additional increase for facilities whose intakes would be difficult to install fish returns.

For further discussion, see Section IX and the TDD (Chapter 8).

2. Entrainment Mortality Technology Costs

Industrial stakeholder commenters argued that closed-cycle cooling costs are underestimated and the cost analysis fails to include any costs for entrainment requirements. Riverkeeper argued that the EPA closed-cycle costs are overestimated.

Response: For both the proposal and this final rule, EPA revised the methodology for estimating closed-cycle costs from what was used for Phase II and Phase III. EPA's revised methodology is based on the cost methodology provided by the Electric Power Research Institute (EPRI). EPRI based its cost methodology on over 50 actual and planned closed-cycle cooling system retrofits and EPA concluded that these cost estimates better reflect actual costs. EPRI has updated their closed-cycle cost methodology since EPA adoption of the earlier version and provided an estimate of closed-cycle costs for generators with a design flow above 50 mgd (See DCN 12–6807). A comparison between the EPRI estimates and comparable EPA estimates indicate that the EPA capital and downtime costs are somewhat lower than the EPRI estimates, while the EPA energy penalty costs are higher. (See DCN 12–6656.) While Riverkeeper cites actual costs from retrofit projects completed in 1998 and 2002 to support the argument that EPA's capital costs are overestimated, EPA has identified more recent closed-cycle retrofits where the capital costs were much higher than the EPA average, suggesting that the costs used by EPA in the final rule are representative of the range of costs that may occur nationwide. (See DCN 12–6656.) Thus EPA considers its closed-cycle costs to reasonably reflect actual costs.

EPA also received estimated costs for closed-cycle retrofits at small, medium, and large manufacturing cooling systems from the American Chemical Council (ACC). A comparison of these costs to comparable EPA estimates indicated that for larger systems the costs are mostly in agreement but that for smaller systems (e.g., 5,000 gpm), the EPA cost estimates are lower. EPA's acknowledges its methodology uses a linear approach and does not fully account for the increased costs associated with the diseconomies of scale at the lower end of the spectrum of system sizes.

Under EPA's selected option, compliance for entrainment reduction requirements is established on a site-specific basis. Because no particular result is prescribed under this approach, it is difficult to ascribe compliance costs for this aspect of the rule without the site-specific information that will be generated as a result of the national BTA standard for entrainment decision-making established by today's rule. For Proposal Options 2 and 3 where closed-cycle cooling would be required, EPA did estimate costs for closed-cycle cooling. EPA has not estimated what site-specific determinations will be made as part of the analysis.

H. Monitoring and Reporting

1. Velocity Monitoring

Many commenters explained that it would be difficult to directly measure through-screen velocity for screen technology and agreed with the suggestion in the NODA that EPA should allow for calculation of through-screen velocity. Also, many were concerned that a velocity limit based on minimum water levels would be difficult to comply with. Of concern are extreme conditions that are beyond the facility's control (e.g., low water due to drought).

Response: EPA agrees that direct measurement of intake velocity on a traveling screen may be problematic in some circumstances, and the final rule allows intakes to comply with the low velocity IM compliance alternatives by either calculation or direct measurement. Compliance will be demonstrated through monitoring and reporting of actual or calculated intake velocities. Short-term exceedances of the velocity may be permissible for brief periods, with Director approval, for purposes of maintaining the cooling water intake system, such as backwashing the screen face. EPA expects that facilities will employ appropriate design and operational measures to ensure that the maximum velocity is not exceeded during minimum ambient source water surface elevations, as can be anticipated through best professional judgment using hydrological data.

2. Impingement Mortality Monitoring

EPA received many comments concerning impingement mortality monitoring. Issues regarding impingement monitoring included the following:

- Many commenters expressed concern that the impingement mortality standard is unclear as to what species the impingement mortality requirements apply.
- Intakes with low impingement would have difficulty calculating impingement mortality.
- Monitoring requirements for impingement mortality are excessive, especially given the physical and biological challenges of appropriate sampling.
- Monitoring requirements should be eliminated for properly installed/operated pre-approved technologies.
- Impingement ''selects'' impaired organisms, resulting in bias.

Response: EPA has addressed concerns regarding monitoring in the final rule. For example, there is no biological compliance monitoring for pre-approved and streamlined compliance alternatives in § 125.94 (c)(1) through (6) of today's rule beyond that required for the permit application, and monitoring may be greatly reduced for other facilities. EPA recognizes that biological monitoring can be expensive, which factored into EPA significantly reducing those requirements. With respect to intakes with low impingement having difficulty calculating impingement mortality, facilities can demonstrate under § 125.94(c)(6) that the rate of impingement is reduced due to intake location or other technologies or factors. Further, under § 125.94(c)(11) a facility can demonstrate to the Director that there is a *de minimis* rate of impingement such that no additional controls are warranted.

3. Reporting Requirements

Comments concerning reporting requirements included the following:

- Commenters argue that permit application deadlines are unreasonable, especially given the limited number of consultants available and that EPA overestimates the number of facilities that have completed these studies.
- Peer review requirements are overly burdensome.
- Permit application requirements are burdensome and EPA should revise the proposed rules to remove, limit, or streamline the numbers and types of data, studies, and reports required. Permit application requirements should be reduced for smaller facilities with intake flow in the 2–125 mgd range.
- The proposed rule requires the § 122.21(r) permit application materials for each permit cycle, regardless of whether the facility has been modified. After the initial assessment of BTA in the first permit cycle under the new rule, the permittee should not be required to do additional studies and submit further documentation unless there is a significant change in the facility's cooling system.

Response: EPA notes that facilities have several flexibilities to address the first point, including: (1) If a permit is issued prior to July 14, 2018, the Director can delay submission requirements until such time that the facility can complete them and (2) in permit terms subsequent to the first permit issued under today's rule, the Director can waive some or all of the studies. With respect to peer review, EPA disagrees that peer review is overly burdensome. How to undertake a peer review is widely known, generally following a well-established process. EPA notes that peer review is a normal part of Agency activities, and that commenters generally favor the application of peer review to environmental data and analyses. With respect to the burden of the permit application process and subsequent permit cycles, EPA has reduced the permit application requirements for the final rule and streamlined biological data collection to two years of data collected as part of the permit application (with the exception of the few facilities expected to comply with the impingement mortality standard under the alternative at § 125.94(c)(7)). In addition, entrainment studies are not prescribed for facilities below 125 mgd, although the Director may require the facility to provide information beyond the basic permit application information. Also, the Director can waive study requirements in permit terms subsequent to the first permit issued under today's rule.

I. Endangered Species Act

Some commenters argued that it is inappropriate to automatically treat T&E species in a special category and provide for special consideration for them under the rule. These commenters asserted that EPA has no basis for incorporating ESA requirements into the rule and addressing ESA species under the NPDES program; they argued that the ESA operates independently. Other commenters argued that EPA has an obligation under the ESA to consult with the Services if cooling water intake structures are likely to affect threatened or endangered species.

Response: EPA has addressed T&E species and critical habitat in this rule to the extent necessary to ensure that this action is consistent with both the Endangered Species Act and CWA section 316(b). Section 7 of the Endangered Species Act states that ''each Federal agency shall, in consultation with and with the assistance of [the services] insure that any action authorized, funded, or carried out by [the agency] . . . is not likely to jeopardize the continued existence of any threatened or endangered species or result in the destruction or adverse modification of [designated critical] habitat.'' Under CWA section 316(b), facilities subject to NPDES permitting that have cooling water intake structures are subject to BTA to minimize adverse environmental impacts. The final rule requires NPDES 316(b) permittees to identify all Federally-listed threatened and endangered species and/or designated critical habitat that are or may be present in the action area. The Director may reject an otherwise available technology as a basis for entrainment requirements if the Director determines there are unacceptable adverse impacts including impingement, entrainment, or other adverse effects to Federally-listed threatened or endangered species or designated critical habitat. EPA consulted with the Services under the ESA regarding this rule, and a summary of the requirements related to threatened or endangered species is discussed in Section VIII.K of this preamble.

VIII. Implementation

The following sections describe how the Agency expects the final rule requirements to be implemented. The requirements of today's final rule will be applied to facilities through NPDES permits issued by EPA or authorized States under CWA section 402. A facility may generally choose to demonstrate compliance with the final rule by demonstrating compliance for the entire facility, or by demonstrating compliance for each individual cooling water intake structure. For example, a facility with two intakes could demonstrate flow reduction commensurate with an existing closed-cycle recirculating system for the first intake, and demonstrate the intake velocity at the screen face is less than 0.5 feet per second at the second intake. Alternatively, the facility could demonstrate that each of the facility's intakes are designed with an intake velocity of less than 0.5 feet per second. For details about the scope and applicability of today's final rule, see Section I above.

Today's final rule (as described in Section IV above) establishes permit application requirements for existing facilities in §§ 122.21 and 125.95, monitoring requirements in § 125.96, and record-keeping and reporting requirements in § 125.97. All existing facilities subject to the final rule that withdraw from one or more cooling water intake structures with a facility-wide DIF of greater than 2 mgd are required to comply with the national BTA impingement mortality standard at § 125.94(c) and national BTA entrainment standard at § 125.94(d). New units at existing facilities are required to meet the national BTA impingement mortality and entrainment standards at § 125.94(e).

The final regulations also require the Director to review permit application materials submitted by each regulated facility, establish impingement mortality and entrainment requirements in accordance with this rule, and issue permits that include monitoring and record-keeping requirements (§ 125.98). The permit application requirements, monitoring, record-keeping, and reporting requirements for each of the compliance alternatives are detailed in the following sections.

A. When does the final rule become effective and how are the requirements sequenced in an orderly way?

This rule becomes effective on October 14, 2014. The requirements in this rule will then be implemented in NPDES permits as the permits are issued.

EPA has sought to address the information and studies required in the permit application associated with ongoing permitting proceedings and subsequent permitting after the first implementation of this rule in a permit. The EPA realizes that, in some cases, a facility may already be in the middle of a permit proceeding at the time of promulgation of this rule, or the Director may have already required much of the same information be submitted by the facility prior to promulgation of today's final rule. Therefore the rule includes several provisions that provide flexibility for the permit application requirements. First, in the case of any permit expiring after July 14, 2018, under § 125.95 the facility must submit permit application materials required in § 122.21(r) with its next NPDES permit renewal application. Second, in the case of any permit expiring prior to July 14, 2018, under § 125.95 a facility may request that the Director waive the submission date of the permit application requirements of § 122.21(r) based on a showing by the owner or operator of the facility that it could not develop the information for which such a waiver is requested by the time required for submission of the permit renewal application. If the Director then chose to allow a delay for the submittal of any of the information requirements of § 122.21(r), the Director would then determine the schedule for submission of any delayed requirements to be as soon as practicable. Third, in the case of permit proceedings begun prior to the effective date of today's rule, and issued prior to July 14, 2018, the Director should proceed. See §§ 125.95(a)(2) and 125.98(g). In such circumstances where permit proceedings have already begun prior to the effective date of the rule, these facilities will still need to submit the appropriate permit application materials found at § 122.21(r) permit applications during their next application. Additionally, while EPA expects that many facilities will already comply with § 125.94(c), in some cases the facility will need to choose one of the compliance alternatives for IM in their subsequent permit cycle.[83] In particular, EPA expects the facility would submit the information required in § 122.21(r), and the Director would make a determination of BTA for entrainment for that facility. Only after the Director has established site-specific BTA requirements for entrainment reduction will the facility have to select the compliance alternative on which it will rely to meet the IM requirements of today's rule. The Director may either amend the permit to include the IM requirements or include them in a subsequent permit if the Director determines the proposed controls are consistent with § 125.94(c). The Director would establish a schedule incorporating each of these sequential actions. In addition, the rule allows the Director the flexibility to grant a request for a waiver of permit application requirements in § 122.21(r)(6) in order to accommodate the circumstances described here. See §§ 122.21(r)(1)(i) and 125.95(a). Fourth, in permit applications subsequent to the first permit issued under § 125.94(a)(1) with all required information submitted under § 122.21(r), the Director may approve a request to reduce information required, if conditions at the facility and in the waterbody remain substantially unchanged since the previous application.[84] See § 125.95(c). In

[83] EPA's costs do not assume zero compliance costs for prior BTA determinations or permit proceedings; all facilities were assessed costs on the basis of technologies in place as described in Section IX.

[84] However, if conditions at the facility or in the waterbody have in fact changed substantially since the previous permit application, the Director will revisit data collection needs and possibly the BTA determination. The presence of any habitat designated as critical, or species listed as threatened or endangered after issuance of the current permit

addition to all of these flexibilities, today's final rule gives advance notice to affected facilities about permit application materials and compliance schedules.

While the final rule has both reduced and streamlined the permit application requirements, the EPA has determined that for many facilities, it may take as long as 39 months to plan, collect, and compile the data and studies required to be submitted with the permit application (see Section C below for a more detailed discussion of each application element). The rule therefore specifies that July 14, 2018 reflects the date after which all permit application requirements must be submitted as specified at § 125.95. Specific permit requirements may not need a full 39 months for completion, therefore the Director may establish a schedule for submission of the required permit application elements. For example, planning for required sampling may take 6 months, inclusive of establishing a sampling team, developing sampling protocols, and acquiring necessary equipment. Source water sampling and characterization under § 122.21(r)(4) includes two years' worth of data. Therefore, the EPA expects a minimum of 30 months will be necessary for submission of § 122.21(r)(4), assuming the facility collects new data; this timeframe could be shorter if the facility chooses to use existing biological data. Facilities choosing to comply with the IM requirements through either § 125.94(c)(5) or (c)(6) must collect at least 2 years data upon which the facility would demonstrate that the modified traveling screens or the facility's systems of technology have been optimized to minimize impingement mortality. Therefore, the EPA expects a minimum of 30 months will be necessary for submission of § 122.21(r)(6), assuming the facility collects new data. Collection of entrainment characterization data and studies should occur in parallel with IM studies and sampling. Thus, after the initial 6 month planning period, facilities that do not already have recent entrainment characterization data will collect a minimum of 2 years entrainment data under § 122.21(r)(9). Facilities are expected to need an additional 9 months to assemble the entrainment data and studies as required by § 122.21(r)(9) through (12). Therefore, the EPA has concluded that as many as 39 months will be necessary for final submission of all requirements under § 122.21(r). This time frame will be adequate for facilities under 125 mgd AIF; facilities over 125 mgd AIF also need to have their 122.21(r)(10) to (12) studies peer reviewed. The EPA expects 3 months will be needed for completion of peer review requirements and generation of a final report. However, many of the facilities over 125 mgd AIF were subject to the Phase II rule before it was suspended (that is, all electric generators over 125 mgd AIF are also above 50 mgd DIF), and likely need less time for up front planning and/or data collection. Therefore, the EPA has concluded that as many as 39 months will be adequate for these facilities to meet all requirements under § 122.21(r). These time frames are consistent with the timeline EPA included in the proposed rule, and also matches the 3½ years previously provided in the Phase II rule for data collection and studies. EPA notes the submission of the studies required with the permit application should not be confused with the schedule for compliance with the BTA requirements, as discussed below.

EPA has also sought to sequence the impingement mortality controls so that a facility may select and implement these controls after the Director's determination of controls on entrainment. With respect to entrainment requirements, existing facilities withdrawing greater than 125 mgd AIF must submit permit application materials including the studies prescribed in today's final rule at § 122.21(r)(9) through (13) in order to help the Director determine what entrainment controls to require at the facility. Facilities at or below this threshold must submit any information requested by the Director. The Director will then review these materials and determine if further entrainment controls are necessary. Once the BTA requirements for entrainment have been established, the facility would finalize its chosen method for compliance with impingement mortality under § 125.94(c). It would then be appropriate for the Director to develop a schedule whereby the facility would proceed to design, construct, and implement its technologies for impingement mortality, for entrainment, or for both together should the same technology addresses both impacts. In this manner, the EPA has harmonized the schedules for meeting both impingement mortality requirements and entrainment requirements.

EPA further notes that approximately 2 percent of facilities have no controls in place for impingement or entrainment, or that a facility may choose to install modified traveling screens as part of its compliance response. In these circumstances, not only does EPA expect such decisions to be delayed until after the Director has determined the BTA requirements for entrainment, EPA acknowledges that the required optimization study of § 122.21(r)(6) cannot be completed until after the technology has been designed and constructed. EPA has provided the Director the flexibility to establish an appropriate schedule for submission of such studies under § 125.95(a)(2).

After the effective date of the regulation, when the first permit implementing the new regulatory requirements is issued, permitting authorities typically consider the need to allow facilities some period of time to come into compliance. Under today's final rule, facilities will have to comply with the impingement mortality and entrainment requirements as soon as practicable according to the schedule of requirements set by the Director. The concept of compliance schedules may be found in the generally applicable NPDES regulations at 40 CFR 122.47. Because section 316(b) has no statutory deadline for meeting the ''best available technology for minimizing adverse environmental impact'' standard, there is no statutory bar to use of a compliance schedule in appropriate circumstances. The EPA recognizes that it will take facilities time to upgrade existing technologies, and install new technologies, and that there are limits on the number of facilities that can be simultaneously offline to install control technology and still supply goods and services to orderly, functioning markets. It is appropriate for the Director to take this into account when establishing a deadline for compliance. Any such schedule would take into account factors provided in § 125.98(c), such as measures needed to maintain adequate energy reliability by an electric generating facility, or extenuating circumstances such as scheduled production outages at a manufacturing facility.

There may be overlap in the technologies used to comply with impingement mortality and entrainment standards, which could result in the facility needing more time to comply with the impingement mortality requirements. For example, if a facility plans to retrofit to wet cooling towers to reduce entrainment, the wet cooling towers technology will also comply with the impingement mortality

(whose range of habitat or designated critical habit includes waters where a facility intake is located) constitutes potential for a substantial change that must be addressed by the owner/operator in subsequent permit applications, unless the facility received an exemption pursuant to 16 U.S.C. 1536(o) or a permit pursuant to 16 U.S.C. 1539(a) or there is no reasonable expectation of take.

standard under § 125.94(c)(1). As such, the Director would schedule compliance with the impingement mortality requirements to match the schedule for entrainment requirements. Further, EPA recognizes that in some cases, especially where additional entrainment control technologies are required, the facility could require a lengthy period of time to design, construct, and implement control technologies. Therefore, the rule authorizes the Director, at § 125.94(h), to establish interim BTA requirements in a facility's schedule of requirements, for impingement mortality, entrainment, or both, where necessary on a site-specific basis.

In contrast to the proposed rule, today's final rule does not include a requirement for compliance with the impingement mortality standards within eight years. EPA expects, however, that the final rule will generally result in compliance within a similar period of time. The combination of permit issuance, the Director's determination of BTA for entrainment, and the subsequent schedule of requirements for impingement mortality will result in some facilities, particularly those already in a permitting proceeding, or with controls similar to what the new permit requires, being in compliance within a very short time frame. Some facilities that are not now in a permitting proceeding may need as much as three and a half years to fully complete their studies and data collection, and depending on the types of control selected, may need additional time to design, construct, and implement their technologies. In some cases, the Director's determination for entrainment may result in a facility meeting both the impingement mortality and entrainment BTA requirements in fewer than eight years. All facilities will be required to follow their schedule as determined by the Director.

EPA notes that there is a three-year period after the effective date of this rule before Directors will be receiving permit applications containing the full set of application requirements in § 122.21(r). EPA is aware that currently many NPDES permits for facilities with a CWIS have been administratively continued. For these administratively continued permits, the Director should consider if any permits would need additional updated information to support the permit issuance decision. The Director may, under 40 CFR 122.21(g)(13), request additional information including any permit application requirements in § 122.21(r).

B. How does the final rule reduce biological monitoring requirements?

The EPA has streamlined the biological data and study requirements for both impingement mortality and entrainment into one comprehensive set of permit application requirements and provisions. The Source Water Baseline Biological Characterization Data, impingement technology performance optimization study, Entrainment Characterization Study, and where applicable, entrainment performance studies are all conducted within the same two year time frame prior to submission of an application for a permit. Further, as shown in Exhibit VIII–1, EPA's analysis indicates that more than 99 percent of existing facilities will choose an alternative for impingement mortality that does not require continual biological compliance monitoring. Thus any required biological data consists solely of that required to be collected to meet the permit application requirements. See Section F for further discussion.

EXHIBIT VIII–1—EPA'S PROJECTIONS OF HOW FACILITIES WILL CHOOSE TO COMPLY WITH THE IM REQUIREMENTS

IM compliance alternative	Intake count [a]	Percent of total intakes
Closed-cycle recirculating system [c]	307	18
Design velocity	362	21
Actual velocity	226	13
Existing offshore velocity cap [c]	10	1
Modified traveling screens	488	29
System of technologies	278	17
Impingement Mortality Performance Standard	12	0.7
De minimis	** [b]	** [b]
Total	1,682	100

[a] EPA's compliance costs for each facility are based on the sum of the facility's intake level compliance costs. Some facilities have more than one intake. See IX.B.2 for more information on the use of the survey data.

[b] EPA has not estimated which facilities will be determined to be "de minimis" under § 125.94(c)(11) by the Director. For purposes of this analysis, EPA has assumed no facilities fall under the "de minimis" provision.

[c] EPA is not projecting facilities will install closed-cycle recirculating systems or offshore velocity caps to comply with the IM requirements, rather these facilities already have these technologies installed.

By merging the data collection and studies into the permit application requirements, EPA expects approximately half of all affected facilities will be able to complete the initial permit application within a few months.[85] In the case of a facility that was not previously required to collect data and conduct studies, it may take up to 45 months lead time for a permit to be applied for, and additional time for the permit to be issued. Although the permit application times may be longer for the first permit cycle after this rule, this is a tradeoff for the flexible IM requirements.

Once the permit is issued, EPA anticipates very few, if any, facilities will be required to conduct ongoing biological compliance monitoring related to impingement controls; for more details, see Section F and Exhibit VIII–4. Instead, for each subsequent permit cycle each facility would either (1) demonstrate to the Director that facility operations and waterbody characteristics are substantially unchanged, or (2) update any biological characterization data. Anticipating that NPDES permits are renewed when they expire, the update to the facility's biological characterization and any corresponding biological performance evaluations would be conducted approximately every five years.

[85] For example, facilities that were subject to Phase II will have already collected most of the data and information as part of the Phase II rule issued February 16, 2004 and implemented up until suspension of that rule on July 9, 2007.

C. What information will I be required to submit to the director when I apply for my NPDES permit?

Today's final rule establishes, at § 122.21(r), permit application requirements for all facilities subject to the requirements of § 125.94. Each permit application element at § 122.21(r) is described in more detail below. The final rule requires existing facilities to prepare and submit some of the same information as previously required for new facilities subject to subparts I or N (*i.e.,* Phase I new power plants and manufacturers or Phase III new offshore oil and gas facilities), namely the information at § 122.21(r)(2) through (4). In addition, the rule adds subparagraphs for existing facilities to the regulations at § 122.21(r)(4), as well as (r)(5) through (13) to include the information and study requirements specific to existing facilities.

In the case of a new unit constructed at an existing facility, EPA expects much of the information submitted by the facility in previous permit applications would still be current and relevant. Therefore, EPA has reduced the permit application requirements to those necessary to update the facility's previously submitted information under § 122.21(r)(2), (r)(3), (r)(4), (r)(5), (r)(6), (r)(7) and (r)(8). In other words, the new unit permit application is intended to describe the changes to these documents as a result of the addition of the new unit. In addition, the facility must submit information specific to the new unit's chosen compliance method at § 122.21(r)(14).

All existing facilities are required to complete and submit permit application studies to describe the source waterbody (§ 122.21(r)(2)), cooling water intake structures (§ 122.21(r)(3)), characterize the biological community in the vicinity of the cooling water intake structure (§ 122.21(r)(4)), cooling water system (§ 122.21(r)(5)), and operational status (§ 122.21(r)(8)). Facilities that already use a closed-cycle recirculating system must still submit this information in their permit application. The Director will need, for instance, the biological sampling data in § 122.21(r)(4) to serve as a record basis for their BTA determination in the permit. Furthermore, in Phase I, new facilities were required to be commensurate with closed-cycle, to meet the 0.5 fps velocity limit, and to collect two years' worth of biological data to establish a record basis for impacts at the facility. In addition, the data collected here is important to inform an owner/operator's evaluation of whether and if so what threatened or endangered species or designated critical habitat are or may be present in the action area.

All existing facilities must describe their existing impingement and entrainment technologies or operational measures and a summary of their performance, including but not limited to reductions in impingement mortality and entrainment due to intake location and reductions in total water withdrawals and usage (§ 122.21(r)(5)(iii)). All facilities must also complete and submit their chosen compliance method for impingement mortality (§ 122.21(r)(6)). This includes identification of any requests for BTA determinations under § 125.94(c)(11) *de minimis rates of impingement* or § 125.94(c)(12) *low capacity utilization power generation units.* In addition, the owner or operator of an existing facility must submit the information required under paragraph (r)(6) of § 122.21 for the alternative specified at 40 CFR 125.94(c) that the owner or operator of an existing facility chooses to rely on as its method of compliance with the BTA Standards for Impingement Mortality specified in 40 CFR 125.94. Because the IM compliance options § 125.94(c)(1), (2), and (4) include pre-approved technologies, the owner or operator of a facility choosing one of these three options to comply with the IM requirements does not have either biological studies or biological compliance monitoring related to the applicable IM standard. Compliance options § 125.94(c)(3), (5), and (6) are streamlined options. For two of these three options, the permit application element § 122.21(r)(6) further requires a site-specific study for the purposes of technology optimization to minimize impingement mortality, including additional biological data collection that in most cases would occur during the same two year period of data collection for the Source Water Baseline Biological Characterization Data required under § 122.21(r)(4) to characterize the baseline, and a demonstration that the operation of specific technologies at your facility have been optimized to minimize impingement mortality. The owner or operator of a facility choosing one of these three options to comply with the IM requirements do not have ongoing biological compliance monitoring as part of the applicable IM standard. As discussed in the previous section, the Director can establish a schedule[86] for submitting the optimization study if the facility first needs to install additional technology for IM.

All existing facilities may submit to the Director additional permit application studies to describe biological survival studies that address technology efficacy and other studies on entrainment at the facility (§ 122.21(r)(7)). This requirement does not impose any new or additional study requirements. This permit application element includes the submission of existing studies conducted by or relevant to the facility. Further, the burden of this requirement has been reduced since proposal by only referring to studies of entrainment.

All existing facilities that withdraw more than 125 mgd AIF[87] of water for cooling purposes must also submit additional information to characterize entrainment and assess the costs and benefits of installing various potential technological and operational controls. These facilities are required to submit to the Director additional permit application studies including § 122.21(r)(9), Entrainment Characterization Study; § 122.21(r)(10), Comprehensive Technical Feasibility and Cost Evaluation Study; § 122.21(r)(11), Benefits Valuation Study; and § 122.21(r)(12), Non-water Quality Environmental and Other Impacts Assessment. As with the biological data collection required of some facilities under § 122.21(r)(6), EPA expects biological data collection for the purposes of entrainment characterization to occur during the same two year period of biological data collection required under § 122.21(r)(4). EPA notes that facilities below the 125 mgd threshold are not automatically exempt from entrainment requirements. The Director may determine that entrainment studies may be required or that entrainment controls may need to be installed for any cooling water intake structure. See the Section VI of this preamble for more information.

The final rule further requires the studies at § 122.21(r)(10) through (r)(12) be subject to an external peer review as required at § 122.21(r)(13); a separate peer review is not required for § 122.21(r)(9), as it is implicitly

[86] The Director could, for example, issue a permit before the optimization study has been completed, and include a schedule for submission of the optimization study in the newly issued permit.

[87] AIF is calculated from the most recent three years' data or five years in subsequent permit cycles. As such, AIF is a variable number. It is possible that a facility could transition from below 125 mgd to above 125 mgd if the facility significantly increases withdrawal of cooling water, such as if the facility increases capacity or if it adds a new unit. In these cases, the facility will then be required to conduct the studies and meet the permit application requirements at § 122.21(r)(9)–(13). This consequence is intended to incentivize facilities to reduce or reuse water for cooling, thereby avoiding the need for additional permit application studies.

reviewed via its use in § 122.21(r)(10) and (r)(11). EPA expects the facility would first notify the Director of the peer review in advance. For example, facilities could identify their peer reviewers near the beginning of their biological data collection for the required Entrainment Characterization Study at § 122.21(r)(9). Since a facility's permit application requires two years of biological data, EPA expects this is more than enough time for the facility to identify peer reviewers, and for the Director to disapprove of a peer reviewer or require additional reviewers. Further, this provides the Director ample opportunity to confer with those agencies with responsibility for fish and wildlife potentially affected by the cooling water intake structure, including other Federal, State, and Tribal agencies. Similarly, in the case of permits for electric generating utilities, EPA expects this is enough time to confer with state co-regulators such as public utility commissions, or independent system operators whose responsibility it is to ensure reliability of the electricity grid. To minimize the overall time required to conduct a peer review, all studies conducted by the facility under § 122.21(r)(10) through (12) will be subject to peer review at the same time, in a holistic fashion. Additional guidance on conducting peer review is available on EPA's Peer Review Program Web site at *www.epa.gov/peerreview*. EPA expects the Director will use the permit application information, studies, and peer review results to assess the impingement and entrainment impacts of the cooling water intake structure and determine appropriate technological or operational controls, or both, as necessary.

While all facilities must submit § 122.21(r)(2) through (6) and (r)(8) and, where applicable (r)(7), EPA has reduced the permit application requirements based on the facility's chosen compliance method for impingement mortality. Exhibits VIII–2 and VIII–3 below illustrate the permit application requirements as they relate to an existing facility's chosen compliance methods. EPA expects permit application requirements for new units will consist of updates to previously submitted permit applications for the rest of the existing facility at which the new unit is being constructed.

For a new unit at an existing facility, EPA expects that only the appropriate and relevant updates to the existing facility's permit application materials are required (in addition to newly developed materials required at § 122.21(r)(14)). For example, the facility would update § 122.21(r)(3) to indicate the addition of the new unit, any new intakes associated with the new unit, expected operational characteristics, etc. For the owner or operator of a new unit and with an AIF greater than 125 mgd, the permit application materials under § 122.21(r)(9)–(13) are required. In those circumstances where data specific to the facility indicate that compliance with the requirements of paragraphs (e)(1) or (2) of § 125.94 for a new unit would result in compliance costs wholly out of proportion to the costs EPA considered in establishing the requirements at issue, or would result in significant adverse impacts on local air quality, significant adverse impacts on local water resources other than impingement or entrainment, or significant adverse impacts on local energy markets, the rule requires the submission of such data as part of § 122.21(r)(14). EPA notes that when a new unit increases an existing facility's AIF greater than 125 mgd, the permit application requirements also include § 122.21(r)(9) through (13). Further, facilities may need several years to complete studies and data collection and, depending on the types of controls selected, may need additional time to design and construct their technology. Thus while the rule requires the permit application for a new unit at least 180 days prior to commencing cooling water withdrawals, it is in the facility's best interest to submit this data well in advance in order to prevent any delays in the Director's review of permit application materials and subsequent issuance or renewal of the facility's NPDES permit. For the owner or operator of a new unit opting to comply via § 125.94(e)(2) the application materials required under § 122.21(r)(14) must demonstrate entrainment reductions equivalent to 90 percent or greater of the reduction that could be achieved through compliance with § 125.94(e)(1).

EXHIBIT VIII–2—SUMMARY OF PERMIT APPLICATION REQUIREMENTS FOR EXISTING FACILITIES ACCORDING TO EXISTING FACILITIES' CHOSEN METHOD FOR COMPLIANCE WITH IMPINGEMENT MORTALITY STANDARD

Compliance approach to impingement	§ 122.21 subsection							
	(r)(2)	(r)(3)	(r)(4)	(r)(5)	(r)(6)	(r)(6)(i)	(r)(6)(ii)	(r)(8)
Closed-cycle recirculating system	Yes	Yes	Yes	Yes	Yes	No	No	Yes.
Design intake velocity	Yes	Yes	Yes	Yes	Yes	No	No	Yes.
Actual intake velocity	Yes	Yes	Yes	Yes	Yes	No	No	Yes.
Existing offshore velocity cap	Yes	Yes	Yes	Yes	Yes	No	No	Yes.
Modified traveling screens	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes.
Combination of technologies	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes.
Impingement Mortality Performance Standard.	Yes	Yes	Yes	Yes	Yes	Maybe	Maybe	Yes.

EXHIBIT VIII–3—SUMMARY OF PERMIT APPLICATION REQUIREMENTS FOR EXISTING FACILITIES: ENTRAINMENT

Compliance approach to entrainment	§ 122.21 subsection						
	(r)(7)	(r)(8)	(r)(9)	(r)(10)	(r)(11)	(r)(12)	(r)(13)
Closed-cycle recirculating system	Yes	Yes	Var.[a]	Var.[a]	Var.[a]	Var.[a]	Var.[a]
Director BTA entrainment determination: facility AIF above 125 mgd.	Yes	Yes	Yes	Yes	Yes	Yes	Yes.
Director BTA entrainment determination: facility AIF 125 mgd or below.	Maybe	Maybe	Maybe	Maybe	Maybe	Maybe	Maybe.

[a] Director has the discretion to waive.

In addition, the Director may set information requirements not included in today's rule to aid in best professional judgment permitting, such as will occur for entrainment at facilities below 125 mgd AIF, and for impingement and entrainment at existing facilities below 2 mgd DIF, neither of which are required by today's rule to submit items in § 122.21(r)(9) through (r)(13). The Director may find aspects of the permit application requirements to be relevant in such situations. A summary of each permit application requirement follows.[88]

1. § 122.21(r)(2) Source Water Physical Data

This requirement is unchanged from the Phase I rule and the 2004 Phase II rule. The facility is required to submit data to characterize the facility and evaluate the type of waterbody potentially affected by the cooling water intake structure. The applicant is required to submit a narrative description and scaled drawings showing the physical configuration of all source water bodies used by the facility, including areal dimensions, depths, salinity and temperature regimes, and other documentation that supports the determination of the waterbody type where each cooling water intake structure is located; identification and characterization of the source waterbody's hydrological and geomorphological features, and the methods used to conduct any physical studies to determine the intake's area of influence in the waterbody and the results of such studies; and locational maps. The Director uses this information to evaluate the appropriateness of any design or technologies proposed by the applicant.

2. § 122.21(r)(3) Cooling Water Intake Structure Data

This requirement is unchanged from the Phase I rule and the 2004 Phase II rule. This data is used to characterize the cooling water intake structure and evaluate the potential for impingement and entrainment of aquatic organisms. Information on the design of the intake structure and its location in the water column allows evaluation of which species and life stages might be subject to impingement and entrainment. A diagram of the facility's water balance is used to identify the proportion of intake water used for cooling, make-up, and process water, as well as any cooling water supplied by alternate sources, such as reuse of another facility's effluent. The water balance diagram also provides a picture of the total flow in and out of the facility, and is used to evaluate gray water, waste water, and other reuses in the facility. The applicant is required to submit a narrative description of the configuration of each of cooling water intake structure and where it is in the waterbody and in the water column; latitude and longitude in degrees, minutes, and seconds for each cooling water intake structure; a narrative description of the operation of each of cooling water intake structure, including design intake flows, daily hours of operation, number of days of the year in operation and seasonal changes, if applicable; a flow distribution and water balance diagram that includes all sources of water to the facility, recirculating flows, and discharges; and engineering drawings of the cooling water intake structure.

3. § 122.21(r)(4) Source Water Baseline Biological Characterization Data

This information is similar to that required in the Phase I rule. Existing facilities are required to characterize the biological community in the vicinity of the cooling water intake structure and to characterize the operation of the cooling water intake structures. This supporting information must include existing data if they are available. However, the facility may supplement the data using newly conducted field studies if it chooses to do so. The information the applicant must submit includes identification of data that are not available and efforts made to identify sources of the data; a list of species (or relevant taxa) for all life stages and their relative abundance in the vicinity of the cooling water intake structure; and identification of the species and life stages that would be most susceptible to impingement and entrainment. All species should be evaluated, including the forage base and those species most important in terms of significance to commercial and recreational fisheries. In addition, the applicant must identify and evaluate the primary period of reproduction, larval recruitment, and period of peak abundance for relevant taxa; data representative of the seasonal and daily activities (e.g., feeding and water column migration) of biological organisms in the vicinity of the cooling water intake structure. In addition, instead of the information required at § 122.21(r)(4)(vi), the owner or operator of an existing facility or new unit at an existing facility must identify all Federally-listed threatened and endangered species and/or designated critical habitat that are or may be present in the action area pursuant to § 125.95(f). The action area can generally be considered the area in the vicinity of impingement and entrainment at the cooling water intake structure. The applicant must also include documentation of any public participation or coordination with Federal or State agencies undertaken. If the applicant supplements the information with data collected using field studies, supporting documentation for the Source Water Baseline Biological Characterization Data must include a description of all methods and quality assurance procedures for sampling, and data analysis including a description of the study area; taxonomic identification to the lowest taxon possible of sampled and evaluated biological assemblages (including all life stages of fish and shellfish); and sampling and data analysis methods. The sampling or data analysis (or both) methods used must be appropriate for a quantitative survey and based on consideration of methods used in other biological studies performed in the same source waterbody. The study area should include, at a minimum, the area of influence of the cooling water intake structure. The applicant may also identify protective measures and stabilization activities that have been implemented and describe how these measures and activities affected the baseline water condition in the vicinity of the intake.

EPA is adding § 122.21(r)(4)(ix), (x) and (xi) to the Source Water Baseline Biological Characterization Data for existing facilities. Item (ix) simply defines the term ''Source Water Baseline Biological Characterization Data.'' EPA is requiring item (xi), identification of fragile species found at the facility. EPA notes that in contrast to the proposed rule, the permit application does not require submission of the proposed ''species of concern.'' EPA found that the term ''species of concern'' was too similar to terms as used in the context of T&E (threatened and endangered) species, and may cause confusion over existing Services or State requirements for such species. Further, despite EPA's efforts to distinguish between species of concern and RIS (representative indicator species) in the NODA (77 FR 34325, June 11, 2011), EPA found that many commenters were still confused by the language. Instead, EPA is adopting the term ''fragile species'' and using the term exactly as it is used with the impingement mortality data and criteria used in calculating the

[88] Where a closed-cycle recirculating system withdraws greater than 125 mgd AIF, the information required in § 122.21(r)(9) to (13) is required, unless the Director reduces or waives some or all of the information required.

impingement mortality standards of the rule. The definition for ''fragile species'' at § 125.92 is a species of fish or shellfish that has an impingement survival rate of less than 30 percent even when the BTA technology of modified traveling screens are in operation. EPA has identified fragile species in the Chapter 11 of the TDD for the final rule. Further, EPA is providing examples, in the list of 14 specific species in today's regulatory definition as a non-exclusive list. This list includes only those species specifically analyzed as part of the performance standards development. If a permit applicant can sufficiently demonstrate a record basis, the permitting Director may deem a particular species to be a fragile species for the purpose of a particular permit.

American shad (*Clupeidae*), bay anchovy (*Engraulidae*), and blueback herring (*Clupeidae*) belong to families that are specifically identified in the TDD Chapter 11 as examples of species that may be, at the Director's discretion, excluded from performance standards on the basis of impingement survival. As another example, threadfin shad (a species not specifically identified as fragile in today's rule) are prone to fall die-off when the water temperature reaches 42 degrees. The EPA does not intend for such naturally occurring mortality to be counted against a facility's performance in reducing impingement mortality. EPA is aware of limited success in flow reduction and behavioral deterrent systems in protecting fragile species. However, there are no demonstrated and available technologies for industry as a whole to address fragile species. EPA has long recognized these species as having low survival rates under the best of conditions, and established different mechanisms to address these in today's final rule. Today's BTA for impingement mortality allows the Director to establish site-specific controls under § 125.94(c)(9) to address fragile species.

EPA notes the change in terminology to ''fragile species'' eliminates the proposed rule burden on States to review and approve each facility's site-specific species of concern, and eliminates confusion over any T&E or RIS that may be subject to more stringent requirements under other Federal, State, and Tribal law. Further, use of ''fragile species'' instead of ''species of concern'' greatly increases the transparency of the Agency's impingement mortality performance standards.

In addition, EPA notes that § 122.21(r)(4)(vi) requires the applicant to submit information on all threatened and endangered species, not just those T&E species that are fish or shellfish. Examples of T&E species that are not fish or shellfish are corals, sea turtles and marine mammals.

4. § 122.21(r)(5) Cooling Water System Data

The Director uses this data in determining the appropriate standards that would be applied to the facility. Facilities are able to use this information, along with the water balance diagram required by § 122.21(r)(3), to demonstrate the extent to which flow reductions have already been achieved at the facility level. The applicant must provide the following information for each cooling water intake structure they use: A narrative description of the operation of the cooling water system and its relationship to cooling water intake structures (including the use of helper towers); the proportion of the design intake flow that is used in the system including a distribution of water used for contact cooling, non-contact cooling, and process uses; a distribution of water reuse (to include cooling water reused as process water, process water reused for cooling, and the use of gray water for cooling); description of reductions in total water withdrawals including cooling water intake flow reductions already achieved through minimized process water withdrawals; description of any cooling water that is used in a manufacturing process either before or after it is used for cooling, including other recycled process water flows; the proportion of the source waterbody withdrawn (monthly); the number of days of the year the cooling water system is in operation and seasonal changes in the operation of the system, if applicable. The applicant must also submit a description of existing impingement and entrainment technologies or operational measures and a summary of their performance, including for example reductions in entrainment due to intake location and reductions in total water withdrawals and usage, and efficiencies in energy production for each producing unit that result in the use of less cooling water, including for example combined cycle and cogeneration. For example, the applicant may provide comparative density data for the intake to demonstrate the extent to which location of the intake has reduced adverse environmental impact. The additional information at § 122.21(r)(5)(iii) is specific to those process units that use cooling water for purposes other than power generation or steam, and where the owner or operator intends to comply with the BTA for IM through either the use of flow reduction measures or the reuse of other water for cooling purposes.

5. § 122.21(r)(6) Chosen Method of Compliance With Impingement Mortality Standard

Today's final rule is flexible in providing seven different compliance options for meeting impingement mortality requirements. Under § 122.21(r)(6), the facility must identify its approach to meet the impingement mortality standards. The facility must identify the compliance method for the entire facility or, alternatively, the compliance method for each cooling water intake structure at the facility. Finding it to be unnecessary because the facility will already have a set of requirements to meet based on its chosen method of compliance, EPA has eliminated the proposed requirement for a separate impingement mortality reduction plan. In addition, monitoring and studies conducted under the reduction plan is no longer required by all facilities. Instead today's final rule specifies data collection requirements only in those instances where the facility must demonstrate a particular performance outcome as described below.

Facilities choosing to comply with § 125.94(c) by operating a modified traveling screen (under § 125.94(c)(5)) must submit an impingement technology performance optimization study under § 122.21(r)(6)(i). The site-specific study must demonstrate the modified traveling screen as defined at § 125.92 has been optimized to minimize impingement mortality. The study must include a minimum of two years of biological data collection. This time frame is consistent with the requirements at paragraph (r)(4)(iv) of § 122.21 to identify primary periods of reproduction and peak abundance, as well as § 122.21(r)(4)(v) to provide data representative of the seasonal activities, both of which would require at least one year worth of data collection. EPA expects facilities will either use existing biological data already required under § 122.21(r)(4) to complete their site-specific impingement studies, modify their biological data collections under § 122.21(r)(4) to be comprehensive and inclusive, use existing performance studies, or collect supplemental data necessary to make their demonstrations. If a facility is using previously collected data or studies that are more than 10 years old, the facility must demonstrate the data is still relevant and representative of the facility. If a facility intends to return organisms to a different waterbody from which they are withdrawn, a request for consideration of this must be made to the Director under § 122.21(r)(6).

The rule specifies sampling at least monthly during the two year data collection effort of the impingement technology performance optimization study, and requires documentation of methods used including counting of moribund organisms, latent mortality, holding times, and counting of entrapment. The Director may establish more frequent collection, as well as specify sampling methods and additional protocols to be used. If the facility intends to return fish and shellfish to a different waterbody than the source waterbody that is used to withdraw cooling water, EPA expects this would be identified as part of § 122.21(r)(6)(i). While EPA does not expect this situation occurs very frequently, the permit application information at § 122.21(r)(6)(i) along with (r)(4) would provide the Director the information needed to determine whether such a return location is appropriate.[89] If the site-specific impingement study demonstrates the modified traveling screen (as defined at § 125.92) has been optimized to minimize impingement mortality, the Director may then determine the modified traveling screen is the best technology available for impingement mortality at the site. The Director would then include permit conditions that ensure the technology will perform as demonstrated. If the Director determines that additional data is required to identify permit operating conditions, the Director has the authority to establish such requirements under § 125.95(d). Note that the EPA envisions the study will function to optimize performance, which is not the same as requiring a study merely demonstrating a specific numeric level of performance for impingement mortality has been or can be achieved. For the majority of facilities, EPA expects annual performance using modified traveling screens will exceed the Agency's calculated average annual performance standards for impingement mortality. Several examples of modified traveling screens in EPA's record show annual performance for impingement mortality that is superior to the impingement mortality performance standard (e.g., lower than 10 percent).

Similarly, facilities choosing to comply with § 125.94(c) by operating a system of technologies (under § 125.94(c)(6)) that will achieve the impingement mortality standard must submit a impingement technology performance optimization study under § 122.21(r)(6)(ii). The site-specific study must provide a description of the technologies, operational measures, or sampling approaches or any combination of them to be used to meet the BTA for impingement mortality. The study must demonstrate that the system of technologies has been optimized to minimize impingement mortality. EPA notes the ''system'' may consist of one or more technologies already in place, or may be combined with newly installed technologies. Further, the study must include a minimum of two years of biological data collection, as just described.

The EPA is aware that it is possible for a facility to reduce its rate of impingement, but the same number of impinged fish die. This has the unintended consequence of increasing the percent impingement mortality calculated by the facility. EPA does not intend for such facilities to be penalized for significant reductions in impingement rates obtained through existing technologies and practices in place. Therefore, one difference in the required study for the system of technologies compliance alternative (as compared to the study required for modified traveling screens) is an understanding that operational measures, best management practices, intake location, and other technologies do not always lend themselves to direct impingement mortality measurements or data collection. Thus the study can include flow measurements and monitoring the rate of impingement (as opposed to directly monitoring mortality) as described below.

If the facility chooses to rely on credit for reductions in the rate of impingement already achieved, the impingement technology performance optimization study must document the reductions to be used as credit. The estimated reductions in impingement must be based on a comparison of the facility to a once-through cooling system with a traveling screen located on the shoreline of the source waterbody. For example, a facility with an offshore intake, an intake canal, or an intake located immediately downstream of a dam in a cold water stream, could demonstrate the population of fish at the intake is lower in these areas, resulting in lower rates of impingement. This provision is intended to allow a facility that conducted or completed a baseline characterization under the Phase II rule to use that same information as part of their demonstration under this rule.

As discussed in Section VI, EPA has identified flow reduction as one of the best ways to reduce both impingement and entrainment. Today's final rule, as part of the system of technologies compliance option at § 125.94(c)(6), provides the owner or operator of a facility the opportunity to demonstrate flow reduction as part of meeting the IM standards. If the facility chooses flow reduction to reduce impingement, the study at § 122.21(r)(6)(ii) must include two years of intake flows measured daily. This flow information plus the data collected under § 122.21(r)(4)(iv) would be used to document how the flow reduction results in a reduced rate of impingement, as well as documenting the extent to which such reductions are seasonal or intermittent. Many pumps operate at only one speed, which doesn't allow the facility to adjust its intake flow to changing conditions. As a potential application of § 125.94(c)(6), EPA is aware of a manufacturing facility that installed multiple pumps of different sizes, and the operator only utilized those pumps that were necessary to obtain the exact amount of cooling water needed. As another example, variable speed drives offer many facilities an opportunity to reduce their intake flows by as much as 10 percent. Variable speed drives are available at all facilities, and EPA expects variable speed drives will be considered when replacing existing recirculating pumps; however, EPA also acknowledges variable speed drives may not be practical in all cases. Nevertheless, EPA expects variable speed drives will be considered by the Director when establishing entrainment requirements under today's final rule. EPA provided an example of how a facility would receive credit for existing technologies in the NODA (see 77 FR 34322, June 11, 2011). An additional sample calculation that includes flow reduction is provided later in this section.

The study must identify each of these contributing components, and requires the calculation of the impingement mortality reflecting each component of the system. The impingement technology performance optimization study must demonstrate the system of technologies has been optimized to minimize impingement mortality. In addition, the study must document the percent impingement mortality

[89] For example, the St. Lucie generating facility determined that this arrangement was not appropriate at their site; see DCN 10–6515. The Brunswick facility, has a fish return flume that goes to a tributary rather than the intake canal or the river. This arrangement places the aquatic organisms away from the intake canal and in a more gentle water environment to increase the organisms' survival; see DCN 10–6569.

reflecting optimized operation of the total system of technologies, operational measures, and best management practices at § 122.21(r)(6)(ii)(D). The Director may then determine the system of technologies is the best technology available for impingement reduction at the site. The Director would then include permit conditions that ensure the technology will perform as demonstrated.

6. § 122.21(r)(7) Entrainment Performance Studies

EPA proposed that a facility must submit all previously conducted performance studies, but has revised this provision in the final rule to include only entrainment related studies. Impingement performance studies, where relevant, are already part of the permit application at § 122.21(r)(6). This avoids imposing a requirement on all facilities to submit previous impingement studies that may be unnecessary, and eliminates a burden on the Director to review all such studies, many of which may no longer be relevant.[90] Under today's final rule, the applicant must submit a description of any biological survival studies conducted at the facility and a summary of any conclusions or results, including the following: site-specific studies addressing technology efficacy, through-facility entrainment survival (distinguished for eggs and larvae), entrainment analyses, or studies conducted at other locations including a justification as to why the data are relevant and representative of conditions at the facility. Because of changes in the waterbody over time, studies older than 10 years must include an explanation of why the data are still relevant and representative of conditions at the facility. If the data are no longer relevant and representative, the Director may reject the data. The Director uses such studies when establishing technology-based requirements for entrainment. Permit applicants are not required to conduct new studies simply to fulfill this requirement. This requirement is rather aimed at obtaining results for relevant studies that have already been conducted as part of past permit proceedings or for other purposes even if those studies were not completed or conducted entirely as planned.

[90] For example, the study may be old and no longer representative, the study may address a pilot study of a technology no longer under consideration by the facility, or the facility may have already selected one of the compliance methods for IM based on pre-approved technologies at § 125.94(c)(1), (2) or (4).

7. § 122.21(r)(8) Operational Status

The applicant must submit a description of the operational status of each unit for which a cooling water intake structure provides water for cooling, including the following: Descriptions of each individual unit's operating status including age of the unit, capacity utilization for the previous five years (including any unusual or extended outages that significantly affect the facility's reporting of flow, impingement, or other data), and any major upgrades completed in the past 15 years (e.g., boiler or condenser replacement, changes to fuel type, a new production line); a description of completed, approved, or scheduled uprates and NRC (Nuclear Regulatory Commission) relicensing status for nuclear facilities; a description of plans or schedules for decommissioning or replacement of units; and a description of current and future production schedules for manufacturing facilities. The Director will use such information in determining the BTA for entrainment as well as when establishing compliance schedules. For example, where the remaining useful plant life is considerably shorter than the useful life of an entrainment technology or where a facility has a planned retirement within the next permit cycle, this information is useful to support a determination regarding that specific entrainment technology. This information would also be used under § 125.94(c)(12) to document infrequently used power generating units that operate with a capacity utilization of less than 8 percent averaged over a 24-month block contiguous period and that the Director may therefore determine warrants IM controls less stringent than § 125.94(c)(1) through (c)(7). With respect to entrainment, the BTA for entrainment is determined by the Director for each site, and energy reliability is one factor the Director may consider when establishing entrainment controls (see § 125.98(f)(3)). EPA expects the information submitted on energy reliability will be considered by the Director when making a BTA determination for entrainment for low CUR units.

8. § 122.21(r)(9) Entrainment Characterization Study

Facilities that withdraw greater than 125 mgd AIF must develop a study that includes a minimum of two years of entrainment data collection. EPA envisions the facility would extend the data collection methods and frequency to develop the source water characterization already required by § 122.21(r)(4) to develop the Entrainment Characterization Study. The study would include complete documentation of the data collection period and frequency of entrainment characterization, and an identification of the organisms sampled to the lowest taxon possible. The data collection must be representative of the entrainment at each intake, and the study must document how the location of the intake in the waterbody and the water column are accounted for. The study must document the intake flows associated with the data collection. Consistent with the permit application requirements requiring biological data collection at § 122.21(r)(4) and (6), EPA requires at least two years of data to sufficiently characterize annual, seasonal, and diel variations in entrainment, including variations related to climate, weather, spawning, feeding, and water column migration. Also consistent with the permit application requirements at § 122.21(r)(4) and (6), facilities may use historical data that are representative of current operation of the facility and conditions at the site with documentation regarding the continued relevance of the data. The study must include analysis of the data to determine total entrainment and entrainment mortality. Documentation in the study must include the method in which latent mortality would be identified, and all methods and quality assurance/quality control procedures for sampling and data analysis would be described. The sampling and data analysis methods must be appropriate for a quantitative survey.

This information will help the Director determine the site-specific BTA for entrainment. For facilities with no entrainment technologies currently in place, this information characterizes the total potential for entrainment. The information can also be used to demonstrate that technologies and other measures already in place, or site-specific factors such as intake location or design, already reduce entrainment. For example, abundance data might demonstrate lower comparative densities that can significantly lower entrainment rates. The information could also be used by new units under § 125.94(e)(2) to demonstrate that an alternative technology or combination of technologies reduce entrainment at that site to a level commensurate with closed-cycle cooling.

9. § 122.21(r)(10) Comprehensive Technical Feasibility and Cost Evaluation Study

The owner or operator of the facility must submit an engineering study of the technical feasibility and incremental costs of candidate entrainment control technologies. The study must include an evaluation of technical feasibility of closed-cycle cooling and fine-mesh screens with a mesh size of 2 mm or smaller, reuse of water or alternate sources of cooling water, and any other entrainment reduction technologies identified by the applicant or requested by the Director. This study must include a description of all technologies and operational measures considered (which could include alternative designs of closed-cycle recirculating systems such as natural draft cooling towers, hybrid designs, compact or multi-cell arrangements, or the conversion of helper towers to a fully recirculating system); and documentation of factors that make a candidate technology impractical or infeasible for further evaluation. For example, a discussion of land availability might include an evaluation of adjacent land, and acres potentially available because of generating unit retirements, production unit retirements, other buildings and equipment retirements, ponds, coal piles, rail yards, transmission yards, and parking lots; decommissioning of existing units; repurposing of existing land uses; documentation that insufficient acres are available on-site; and evidence of the feasibility of the purchase or other acquisition of property adjacent to the facility.

For the analysis of water reuse and use of alternate sources of cooling water, the owner or operator must examine the available alternatives for reuse of effluent from within the facility or from other dischargers in the vicinity. The volume of water available need not be for the full intake flow; reuse of water could contribute to a partial reduction in flow at the facility. Additionally, if the facility were to retrofit to a closed-cycle system, the significant reduction in flow may make nearby alternative sources more feasible. This analysis should include an estimate of the cost to build any new infrastructure (e.g., piping, pump houses) and the ongoing operational costs (e.g., pump costs) for the Director's consideration.

The final rule requires that the cost information be presented as both the facility's compliance costs and the social costs, and in net present value (NPV) terms and the corresponding annual value. Social costs are the costs estimated from the viewpoint of society, rather than individual stakeholders. Social cost represents the total burden imposed on the economy; it is the sum of all opportunity costs incurred. See Chapter 8 of EPA's 2010 Guidelines for Preparing Economic Analyses (DCN 10–3258). Some adjustments to facility compliance costs to produce social costs cause them to be higher than compliance costs, while other cause social costs to be lower. Although a facility makes investment decisions by taking tax consequences into account (after-tax costs), the favorable tax treatment of investments is viewed as a transfer and not a real resource cost, thus pre-tax costs are used in social cost analysis. From society's viewpoint, costs in the future must be amortized and discounted to net present value using a social discount rate, rather than a market cost of capital as reflected in market interest rates. The Office of Management and Budget (OMB) Circular A–4 (DCN 10–3266) instructs agencies to use both 3 percent and 7 percent discount rates. Certain administrative costs are not borne by a facility, but rather by the Director, and are social costs. Compliance costs include the facility's administrative costs, including costs of permit application, while the social cost adjustment includes the Director's administrative costs. EPA has estimated the Directors' administrative costs in the ICR for the final rule, and describes the methodology for estimating these costs in detail in the EA. Facilities may adopt a similar approach to including Director's administrative costs in their social cost estimates. In addition, this component is not expected to be large or to vary significantly across technology options considered.

From a facility's viewpoint, downtime costs include lost net revenue, while from society's viewpoint, if another facility is dispatched or inventory of manufactured goods can be sold, the only social cost of downtime is any increase in marginal costs of production at other facilities dispatched or the cost of holding inventory. Unless a facility can demonstrate that its costs of compliance will result in lower overall supply in the markets in which its products are sold, and that the effect of the lowered supply is an increase in market price and lower quantity of product sold, the facility should not make a social cost adjustment to reflect these larger market impacts.

In addition to the required social costs, the owner or operator may choose to provide facility level compliance costs; however, such costs must be provided and discussed separately from social costs. The cost evaluation component of this study must include engineering cost estimates of all technologies considered above and also discuss and provide documentation of any outages, downtime, energy penalties or other effects on revenue. The cost evaluation should be based on least-cost approaches to implementing each candidate technology while meeting all regulatory and operational requirements of the facility. Depreciation schedules, interest rates, further consideration of remaining useful life of the facility as discussed in § 122.21(r)(8), and any related assumptions must be identified. The owner or operator of the facility must obtain peer review of the Comprehensive Technical Feasibility and Cost Evaluation Study, as described in Section 12.

10. § 122.21(r)(11) Benefits Valuation Study

The owner or operator of the facility must submit a detailed discussion of the benefits of the candidate entrainment reduction technologies evaluated in § 122.21(r)(10) and using data in the Entrainment Characterization Study in § 122.21(r)(9). Each category of benefits should be described narratively, and when possible benefits should be quantified in physical or biological units and monetized using appropriate economic valuation methods. This includes incremental changes in the impingement mortality and entrainment of individual fish and shellfish for all exposed life stages, estimation of changes in stock and harvest levels of commercial and recreational species, and description of any monetization. This may include monetization using market values, market proxies (*e.g.,* models based on travel costs or other methodologies), benefits transfer and stated preference methods. Benefits that cannot be monetized should be quantified where feasible and discussed qualitatively where not. The study must identify increased or decreased thermal discharges, and must evaluate the potential changes in facility capacity, operations, and reliability due to relaxed permitting constraints related to thermal discharges. The study must also include discussion of recent mitigation efforts already completed and how these have affected fish abundance and ecosystem viability in the intake structure's area of influence. Finally, the study must identify other benefits to the environment and the community, including improvements for mammals, birds, and other organisms and aquatic habitats. The owner or operator of the facility must obtain peer review of the benefits evaluation study, as described in Section 12. EPA expects peer reviewers to have appropriate qualifications (*e.g.,* fisheries biologist, economist) for the subject matter. The Director may consult with EPA and Federal, State and Tribal fish and wildlife management agencies with responsibility for fish and wildlife potentially affected by the cooling water intake structure(s) to determine which peer review comments must be addressed by the final study. The dollar values in the social benefits analysis should be based on the principle of willingness-to-pay (WTP), which captures monetary benefits by measuring what individuals are willing to forgo in order to enjoy a particular benefit. While the Director must consider benefit and cost information, the Director will also determine if this information is of sufficient rigor to make a decision on entrainment controls on the basis of this information. For instance, the Director may decide not to rely on benefit-cost information in establishing the entrainment controls when the benefits analysis includes only a qualitative discussion of nonuse benefits. Willingness-to-pay for nonuse benefits can be measured using benefits transfer or a stated preference survey. However, the rule does not require the Director to require a facility owner or operator to conduct or submit a stated preference survey to assess benefits.

11. § 122.21(r)(12) Non-Water Quality Environmental and Other Impacts Assessment

The owner or operator of the facility must submit a detailed discussion of the changes in non-water quality environmental and other factors attributed to technologies or operational measures, or both, considered. These changes may include, for example, increases or decreases in the following: Energy consumption; air pollutant emissions and their health and environmental impacts; noise; safety concerns, such as the potential for plumes, icing, and availability of emergency cooling water; grid reliability, including an estimate of changes to facility capacity, operations, and reliability due to cooling water availability; consumptive water use (including effects of surface water evaporation of thermal discharges); and facility reliability, such as production of steam and impacts to production based on process unit heating or cooling. The owner or operator of the facility must provide for peer review of the Non-Water Quality Environmental and Other Impacts Assessment as described in the following section.

12. § 122.21(r)(13) Peer Review

The owner or operator of the facility must provide for peer review of the permit application studies required at § 122.21(r)(10) Comprehensive Technical Feasibility and Cost Evaluation Study, § 122.21(r)(11) Benefits Valuation Study, and § 122.21(r)(12) Non-Water Quality and Other Impacts Assessment. While facilities that withdraw more than 125 mgd AIF must conduct these studies and therefore must provide for peer review, facilities that withdraw equal to or less than 125 mgd AIF may have study requirements including peer review as determined by the Director. In today's final rule, EPA did not adopt separate peer review requirements for the Entrainment Characterization Study at § 122.21(r)(9), because this data would be included in the Comprehensive Technical Feasibility and Cost Evaluation Study, Benefits Valuation Study, and Non-Water Quality and Other Impacts Assessment, and these studies are already subject to peer review. For these reasons, EPA reduced the burden in the final rule by eliminating the peer review requirement for entrainment characterization.

EPA recognized at proposal that in many cases it is more efficient for permit applicants to combine the required studies into one document and have them reviewed holistically by a single set of peer reviewers. Such an approach is allowed by the final rule, as long as the peer review panel has the background appropriate to conduct a complete and combined review and the Director approves.

The Director may consult with Federal, State and Tribal fish and wildlife management agencies with responsibility for fish and wildlife potentially affected by the cooling water intake structure(s). Further, the Director may require the owner or operator of the facility to include additional peer reviewers of the studies. EPA expects peer reviewers to have appropriate qualifications (e.g., in the fields of biology, engineering) for the subject matter. An explanation for any significant reviewer comments not accepted must be included in the final study submission. Additional guidance on conducting peer review is available on EPA's Peer Review Program Web site at *www.epa.gov/peerreview.*

13. § 122.21(r)(14) New Units

New units at existing facilities must identify the compliance method for the new unit under the permit application requirements at § 122.21(r)(14). Where the facility complies with BTA standards for entrainment at § 125.94(e)(1) by reducing its intake flows commensurate with that of a closed-cycle recirculating system (as defined at § 125.92(c)(1)), the BTA standards for impingement mortality will have been met by § 125.94(c)(1). To comply with the alternative at § 125.94(e)(2), there must be a demonstration that entrainment reductions equivalent to 90 percent or greater of the reductions that could be achieved through compliance with § 125.94(e)(1).[91] In this case, permit application requirement § 122.21(r)(14) requires this demonstration to include the Entrainment Characterization Study at § 122.21(r)(9). The Director may determine additional data and information, including data collection, is necessary to make the demonstration.

D. When are permit application studies due?

The owner or operator of a facility applying for reissuance of a permit must submit the information required at § 122.21(r) to the Director no later than 180 days before the current permit expires. Those facilities that were subject to the section 316(b) Phase II rule from February 16, 2004 until suspension of that rule on July 9, 2007 were already collecting some information required at § 122.21(r). EPA has structured this rule to take advantage of those data and expects facilities to use them when they satisfy requirements for permit applications.

In some cases, required permit application information might have been collected, but reports might not have been generated or finalized prior to the rule suspension in 2007. Further, facilities not subject to the Phase II rule (e.g., existing power plants below 50 mgd DIF and all existing manufacturers) might not have collected this information or might not have collected information to identify permit operating

[91] Note that a new unit may construct a new intake structure or utilize capacity from an existing intake structure. For the former, the requirements of § 125.94(e)(1) are simple to conceptualize and apply. But for the latter, EPA clarifies that the new unit requirements only apply to that portion of the flow that is serving the new unit. For a new unit using an existing intake structure that chooses to comply using § 125.94(e)(1), demonstrating that the new unit achieves the required reduction in flow should be a relatively simple exercise in identifying intake flows and the distribution of cooling water from the intake structure. For a new unit using an existing intake structure that chooses to comply using § 125.94(e)(2), the facility would demonstrate that it has reduced entrainment for that portion of the intake flow serving the new unit by 90 percent; the facility would not be required to reduce entrainment for the flow of the entire intake structure by 90 percent, unless the Director makes such a site-specific determination for entrainment at the existing units as well.

conditions. In those cases, facilities would have to collect additional data in order to have two years of biological data collection. EPA expects associated studies and reports will take several additional months to complete. For this reason, EPA has established a provision for permit application submittal for a permit expiring prior to July 14, 2018, allowing the Director flexibility to delay application requirements based on a showing by the owner or operator that it could not develop the information by the time required for submission of the permit application. The Director would then establish a schedule for submission of the delayed permit application requirements. EPA notes that the Director has the discretion to require additional studies, data collection, or an on-site inspection as part of the permit process.

Facilities whose permit expires after July 14, 2018 would submit all required materials in § 122.21(r) with their permit renewal application.

New units at existing facilities must submit the information required at § 122.21(r) to the Director no later than 180 days before commencing operation of the new unit. Because these units are being constructed at a facility that is already operating, the facility will have already submitted many of the permit application materials. The addition of a new unit would require an update of or supplement to permit application materials that have already been submitted. New units take significant time and resources to plan, design, and construct; therefore the final rule does not have a provision to waive permit application requirements based on a showing by the owner or operator that it could not develop the information by the time required for submission of the permit application. For permit renewals subsequent to the first permit issued under today's rule, the new unit would be included in the assessment of the entire facility and would no longer require unique permit application submissions. As discussed previously, the owner or operator is encouraged to submit applications well in advance of the 180 day requirement to avoid delay.

EPA is aware that some intake structures withdraw from a manmade lake or reservoir that is stocked and managed by a State or Federal natural resources agency. In some cases, the biological characterization of the source water is heavily influenced by the actions of the natural resources agency. Further, the results of biological data collection and studies may be confounded by such actions. Today's final rule at § 125.95(a)(3) gives the Director discretion to waive some or all of the permit application requirements of § 122.21(r) in such circumstances.

In permit terms subsequent to the first permit issued under the final rule, the facility will re-submit the § 122.21(r) permit application studies, while the rule still includes two years of biological data collection for some facilities. In this manner, the biological characterization over time would be routinely evaluated, i.e., every 5 years under a standard permit cycle. To reduce the burden of such data collection, however, the final rule provides that the owner or operator of a facility may submit a request to the Director to reduce the information required. See 40 CFR 125.95(c). In most cases, EPA anticipates the facility would make any such request prior to conducting its two years of biological data collection. Therefore the request for reduced information requirements must be submitted to the Director at least two years and six months before the expiration of the facility's NPDES permit. The Director may approve such a request if conditions at the facility and in the waterbody remain substantially unchanged since the previous permit application.[92] EPA expects the Director would assess the relevant previously submitted information and determine whether it remains representative of current source water, intake structure, cooling water system, and operating conditions. Accordingly, the Director may accept or reject any part of the request.

E. How will the director determine the best technology available for minimizing adverse environmental impacts?

1. Review and Approval of Permit Application Materials

Under today's rule, the Director will review all materials submitted by an existing facility with its permit application to determine appropriate NPDES permit conditions and requirements to minimize impingement mortality and entrainment. As stated at 40 CFR 125.98(a), the Director shall not issue a permit before receiving a permit application form and any supplemental information which are completed to his or her satisfaction (see existing Permit Application and Special NPDES Program Requirements at 40 CFR 122.21(e)).

Facilities with a design intake flow at or below 2 mgd will continue to have permit conditions set on a case-by-case, best professional judgment basis under 40 CFR 125.90(b) and 401.14. For such facilities, however, the Director may choose to apply some portions of the permit application conditions in today's rule to aid in the BPJ determination.

The Director is encouraged to expeditiously provide any comments on submitted materials so the facility can make responsive modifications to its information gathering activities. For permit applications subsequent to the first permit issued under today's rule, the Director could indicate whether reduced or different information must be submitted with the permit application. More specific responsibilities are described below:

a. If the Director has made a BTA determination for entrainment before the effective date of the rule, and substantially the same information was already submitted and considered by the Director in making that determination, under § 125.98(g) the Director may proceed with the Determination of BTA without requiring the owner to submit the information required in § 122.21(r).

To clarify further, EPA has included a ''transition'' provision at § 125.98(g) of today's rule that makes it clear that for any facility that has submitted a permit application before the effective date of the regulation, the Director may select the best approach to development and implementation of the next permit. These provisions are intended to avoid any unnecessary delay in recently submitted permit applications or draft permits. EPA expects that facilities will continue with any data collection requirements, study requirements, and schedules in recently issued permits.

b. If the Director establishes a compliance schedule under § 125.94, the Director will establish a schedule that sets requirements as soon as practicable. In establishing the schedule, the Director is encouraged to consider the extent to which those technologies proposed to be implemented to meet the requirements of § 125.94(d) will be used, or could otherwise affect a facility's choice of technology, to meet the requirements of § 125.94(c). Impacts of thermal discharges, along with other stressors, might be a relevant consideration when assessing benefits of technologies to reduce impacts of cooling water intakes or discharges. The Director is also encouraged to consider energy reliability, transmission capacity, and

[92] The presence of any habitat designated as critical, or species listed as threatened or endangered after issuance of the current permit (whose range of habitat or designated critical habit includes waters where a facility intake is located) constitutes potential for a substantial change that must be addressed by the owner/operator in subsequent permit applications, unless the facility received an exemption pursuant to 16 U.S.C. 1536(o) or a permit pursuant to 16 U.S.C. 1539(a) or there is no reasonable expectation of take.

grid requirements when establishing a schedule for electric power generating facilities. The Director may confer with local and regional electric power agencies and state utility regulators when establishing a schedule for electric power generating facilities (see DCN 10–6860 for information on the approach taken by California). The Director may determine that extenuating circumstances (e.g., lengthy scheduled outages, future production schedules) warrant establishing a different compliance date for any manufacturing facility.

c. The Director will review the permit application materials and studies submitted under § 122.21(r) and determine which entrainment controls are appropriate. Factors that must be considered and factors that may be considered in making the determination are provided at § 125.98. The Director must issue a written explanation for the BTA determination and must make this determination, and any other information submitted by third parties, available with the permit for public review. This determination is expected to be issued as part of the permit's statement of basis under 40 CFR 124.7.

2. Role of Social Cost-Benefit Analysis in Permit Determinations

In deciding what technology to require a permittee to install to address entrainment, the Director may undertake an evaluation of social costs and benefits of implementing such requirements. This analysis will be based on the information submitted by the applicant, supplemented by any information submitted by third parties, and additional information as determined appropriate by the Director. EPA recognizes the resource limitations faced by permitting authorities and does not generally expect that the Director would develop additional information on which to base the evaluation of social benefits and costs, although the Director may opt to do so. This analysis should evaluate benefits and costs from the perspective of society as a whole, rather than costs and benefits accruing to limited parties (e.g., very local populations or the permittee, which presents a limited set of information to the Director).

It is also important to note that the stated preference survey conducted by EPA which was discussed in the June 12, 2012 Notice of Data Availability (77 FR 34927) was designed to estimate respondents' willingness to pay for changes in the health of fish populations and aquatic ecosystems and be statistically representative at large (regional and national) scales; the results were not designed to be statistically representative at the facility level for the assessment of benefits for individual site-level permitting decisions. Today's final rule does not require the Director to require a facility owner or operator to conduct or submit a stated preference survey to assess benefits. Further, the rule does not limit the Director's discretion to consider non-water quality impacts in determining whether further entrainment measures are justified.

A number of cost elements should be accounted for in assessing the social cost of entrainment technology implementation. These are summarized below.

a. Technology Installation Cost

These peer-reviewed engineering cost estimates of the physical construction of candidate entrainment technologies at the facility are required. These costs would be provided by the applicant under § 122.21(r)(10).

b. Installation Downtime Cost

Installation of closed-cycle cooling systems will often require facilities to take additional downtime beyond ordinary annual maintenance downtime. An estimate of downtime cost to the facility is required under § 122.21(r)(10). EPA expects a facility will document that portion of downtime that is incremental to any downtime the facility already incurs due to, for example, routine maintenance outages, overhauls, refueling, and periodic replacement of equipment that is at the end of its useful life. Downtime costs to the facility include the value of lost production (e.g., electricity) minus any variable cost savings, as well as any other costs to the facility associated with downtime (shutdown and startup routines, special maintenance protocols, etc.) minus any savings associated with downtime. If they are considered in the social costs analysis, downtime costs must be adjusted to reflect production made up by other facilities or firms, because these temper the real resource costs from society's viewpoint. The cost of downtime is determined on a different basis for social cost. Specifically, the cost of downtime to society is the cost incurred for other facilities and generating units to make up the electricity or manufactured goods that would have otherwise been generated by the facility minus the cost that would have otherwise been incurred by the facility incurring downtime. This difference in cost reflects the additional cost, if any, that society must pay to generate the replacement goods, and may differ substantially from the cost of downtime to the facility.

c. Energy Penalty Cost

Operation of closed-cycle cooling systems may impose an energy penalty. EPA is using energy penalty to mean only the opportunity costs associated with reduced power production due to derating (turbine backpressure). Energy penalty does not include the costs to operate pumps and fans associated with closed-cycle cooling, which are operation and maintenance costs (and covered below). Under well-established principles in benefit-cost analysis, the cost of the energy penalty to the facility is not the opportunity cost to society. Instead, the cost to society is the cost of generating the electricity, whether incurred by the regulated facility or another facility, that is no longer available for consumption because of the energy penalty. This cost may be incurred by the facility, if it can increase the energy input to, and output from, the generating unit to generate the electricity that is otherwise no longer available for consumption, or by another generating unit if the regulated unit cannot make up the electricity. In either case, the social cost of the energy penalty is the cost of generating the electricity that would otherwise be available for consumption except for the energy penalty. Again, an assessment of these costs would be determined under the § 122.21(r)(10) demonstration.

d. Operation and Maintenance Costs for the Entrainment Technology Equipment

The cost of energy to operate the entrainment technology for electric generators should appear in the operation and maintenance costs, along with other labor and materials costs. In the same way as described above, the social cost of the energy required to operate entrainment technology is the cost for generating this electricity, as it is otherwise no longer available for end-use consumption. This cost could be incurred by the regulated facility, if it has sufficient capacity to make up the loss, or by another facility, if the regulated facility is not capable of generating the electricity that is no longer available for end-use consumption.

e. Other Administrative Expenses

This includes additional permitting or reporting expenses, or both. For social costs, the estimate should include the costs to the facility and those expected to be incurred by the Director.

EPA has estimated the Directors' administrative costs in the ICR for the final rule, as explained in the EA, and facilities may adopt a similar approach to estimating these costs at the permit level. For assessing social cost, the cost elements outlined above would typically be accounted for on a real cost basis—that is, pre-tax and without adjusting for future inflation. Costs are tallied over an appropriate time frame, which will typically be the expected useful life of the technology installation or the remaining life of the facility, if less. Costs should be calculated as both net present value and annualized values, using an appropriate social discount rate. The applicant should document the basis for the discount rate chosen, and its methodology and calculations.

f. Benefits

In assessing the benefits of entrainment technology installation, the Director would assess the value to society from the reductions in impingement mortality and entrainment that would result from installation of a closed-cycle cooling system, fine mesh screens, or other entrainment technologies. All benefits, including monetized, quantified and qualitative benefits, should be considered in this assessment. The benefits assessment would typically look at a range of potential benefit categories, including increased harvest for commercial fisheries, increased use values for recreational fisheries, and nonuse values (existence and bequest values). The latter may be difficult to quantify or monetize. If appropriate data are available from benefits transfer or conducting stated preference studies or other sources that can be applied to the site being evaluated, these should be used to monetize nonuse values. Otherwise, nonuse values should be evaluated quantitatively and/or qualitatively. Quantitative analysis, even without monetization, can be quite useful in evaluating nonuse benefits. For example, quantifying impacts to forage and threatened and endangered species, and other indirect impacts on the aquatic environment, might allow the Director to derive a much more complete understanding of benefits as compared to a qualitative narrative, even if not directly comparable to monetary costs.

Quantifying and valuing the benefit categories listed above involves significant challenges, as described in the BA. For example, assessing the productivity and value of commercial fisheries involves estimating the expected increases in commercial yield of economically valued species over time as a result of reduced impingement mortality and entrainment, and valuing these at market prices minus any incremental production costs associated with the incremental catch. Similarly, assessing recreational use benefits involves estimating the improvements in recreational fishing opportunities resulting from reduced impingement mortality and entrainment, and assigning a value to these improvements. The value assignment is based on the estimated population profile—in particular, number and proximity to affected water resources—of recreational users, the availability of alternative competing water resources for recreational usage, and the resulting estimated change in demand for use and value of the affected water resources based on reduced impingement mortality and entrainment and increased recreational fishing performance. EPA acknowledges this could be difficult to do even on a site-specific basis.

Nonuse benefits, which encompass existence and bequest values, include impacts in such areas as population resilience and support, nutrient cycling, natural species assemblages, and ecosystem health and integrity. Nonuse values include improving the survival probability of a threatened or endangered species if present in the vicinity of the facility. Benefits might also need to be assessed beyond the vicinity of the facility's intake if migratory species are affected by the intake. Residual impacts of thermal discharges might also be appropriate to consider in the social benefits calculation.

In much the same way as described for the social cost assessment, social benefits are tallied yearly over the expected performance life of the compliance technology. This tallying should account for the ''phase-in'' of benefits (e.g., benefits may build up over time as the impingement mortality and entrainment reductions affect commercial fisheries productivity). Benefits are computed on a present value basis and annualized using an appropriate discount rate as described above. The same discount rate should be used for benefits and costs. Often, it is appropriate to calculate benefits and costs using more than one discount rate. For example, for regulatory impact analysis, OMB recommends that Federal agencies use both a 3 percent and a 7 percent rate. However, comparisons between specific benefit and cost numbers should always involve values computed using the same rate.

The resulting estimates of social cost and benefits must be considered in determinations on whether to require a permittee to install entrainment technology and the specific level of entrainment technology to be installed. The Director may reject otherwise available technologies as the BTA requirements for entrainment controls if the social costs of compliance are not justified by the social benefits, or if there are other adverse impacts that cannot be mitigated that the Director deems to be unacceptable. If all technologies considered have social costs not justified by the social benefits, or have unacceptable adverse impacts that cannot be mitigated, the Director may determine that no additional control requirements are necessary beyond what the facility is already doing. The Director should document the basis for such a determination and include it in the public notice for the draft permit.

3. Streamlined Process

The process for complying with the impingement mortality standards is expected to be highly streamlined. As shown in Exhibit VIII–1, EPA expects more than 99 percent of facilities will comply by one of the six compliance options that do not require continual biological compliance monitoring (one of the three compliance alternatives based on pre-approved technologies or one of the three streamlined compliance alternatives). If a facility chooses to comply by operating a modified traveling screen, the Director will review the impingement technology performance optimization study, including the identification of species, duration and structure of the study, and any monitoring requirements.

4. De Minimus Provision

The Director may, based on a review of data submitted under § 122.21(r), conclude that the documented rate of impingement at the cooling water intake structures is so low that no additional controls are warranted. As described in section I.A.H, low flow facilities may in particular be candidates for such consideration, although the authority of the Director is not limited to low flow facilities. The Director may want to consider facility withdrawal rates in relation to the mean annual flow of the river and possible co-location with other CWISs when making a de minimis determination. Notice of this determination would be included in the draft permit made available for public comment, and the Director's response to any comment on this determination must be included in the record for the final permit. EPA considers low rates of impingement to be measured as an organism or age-one equivalent count, and not as the effect of impingement on fish populations. The Director may require data collection to demonstrate support for a de minimis level of impingement. In addition, EPA does not expect that a de minimis exemption would apply to facilities with no technology present other than trash racks, a technology that nearly all facilities employ. In making a determination that no additional controls are warranted, the Director may wish to consider factors such as whether the waters are subject to a TMDL for an aquatic life use, the waters are not attaining a designated use, and there would be more than minor detrimental effects on threatened or endangered species or critical habitat. The Director will still establish proper operation and maintenance conditions in the permit whenever making a de minimis finding that no additional controls are warranted. EPA notes that the de minimis provision for impingement does not necessarily mean a facility has a de minimis level of entrainment. The life stages affected by impingement are different than those affected by entrainment, and low counts of impingeable life stages do not always mean the counts of entrained organism are similarly low. Since the entrainment requirements are already determined by the Director for each site, EPA concluded that specific regulatory language for de minimis entrainment was unnecessary.

5. Low Capacity Utilization Units

The Director may consider less stringent controls for intakes dedicated to low capacity utilization rate (CUR) power generating units. If an existing facility has a cooling water intake structure used exclusively for one or more existing electric generating units, each with an annual average capacity utilization rating of less than 8 percent averaged over a 24-month block contiguous period, the owner or operator may request that the Director establish BTA standards for impingement mortality for that cooling water intake structure which are less stringent than § 125.94(c)(1) to (c)(7). When determining the permit's IM requirements associated with the low CUR unit, the Director may consider, after conferring with any appropriate state co-regulators (such as public utility commissioners) and with regional transmission organizations, independent system operators or other planning authorities, the significance of the unit's operation to the overall reliability of electric power in the area.

In addition, in determining the IM requirements associated with a low CUR unit, the Director should consider any seasonal factors for affected species that might justify seasonal limits on the unit's operation, for example any increased impacts resulting from the unit's operation during spawning runs. Also, when considering the presence and potential effects to threatened and endangered species, the Director should consider whether the life stages present at the location are at risk of being impinged or entrained at the low CUR unit's cooling water intake.

In the event that the Director determines less stringent controls for intakes dedicated to low capacity utilization power generating units are appropriate, they should consider, at a minimum, the following in establishing controls:

Strategies for minimizing water withdrawal during stand by periods of operation, startup/shutdown, and on-line periods of operation;

The effectiveness of installing variable speed pump drives to reduce water withdrawals during all periods of operation, particularly during stand-by periods of operation; and

The effectiveness of installing alternative equipment (e.g. behavioral deterrents) to minimize impingement mortality.

The owner or operator would demonstrate whether they have an intake only serving one or more low capacity utilization power generating units in permit application requirements at § 122.21(r)(3) and (8). Under § 122.21(r)(6), the owner or operator would indicate a request that the Director establish alternative BTA standards that are less stringent than § 125.94(c)(1) through (7). EPA recognizes the contribution of peaking units in serving peak electricity demands, and maintaining a reliable electricity grid. However, if peaking units are in standby mode for long periods relative to periods when they are generating electricity, the result is a capacity utilization of the cooling water intake that is greater than the capacity utilization of the generator. Significant periods of standby could contribute to a greater impact on aquatic life. While the 8 percent capacity utilization is an industry standard that distinguishes those units making the greatest contribution to a smoothly functioning electricity grid, a Director may still determine that the impacts to aquatic life are significant enough to deny a request that BTA at that intake should be less stringent than § 125.94(c)(1) to (c)(7). EPA anticipates the Director will have the information necessary to determine BTA in such circumstances based on the permit application requirements, including but not limited to an identification of the number of days the cooling water system is in operation, flow on those days, and seasonal changes in the operation of the system under § 122.21(r)(5) and the biological information under § 122.21(r)(4).

As discussed previously, the Director will determine the BTA for entrainment for low CUR units on a site-specific basis. EPA expects that many of the same factors discussed above—including the significance of the unit's operation to the overall reliability of electric power in the area, the diversity of fuels available for the unit, and the impact of the costs of any potential entrainment requirements on the unit's cooling water intake structure on overall reliability of electric power in the area—will be relevant in making site-specific BTA entrainment determinations for low CUR units. The Director may consider the factors at § 125.98(f)(3) when making these determinations for low CUR units, which includes grid reliability, among other factors.

6. Monitoring

The Director will review any impingement mortality and entrainment monitoring reports submitted by the facility to ensure ongoing compliance. EPA is shifting toward an electronic discharge monitoring report system, and many of the impingement mortality and entrainment standards can be incorporated into the discharge monitoring report itself, rather than requiring a separate report. Except for facilities choosing alternatives § 125.94(c)(7), detailed biological data collection would only be included as part of the facility's permit application submission and not for compliance purposes. The Director has the discretion to request additional information, including inspection of the facility, at § 125.95(d) (*i.e.,* permit application and supporting information requirements) and § 125.96(c) (*i.e.,* additional monitoring requirements).

7. Nuclear Units

The rule includes a provision that permits the owner of a nuclear facility to demonstrate to the Director that compliance with the rule would result in a conflict with safety requirements for their facility. See § 125.94(f). EPA anticipates that this provision would be implemented as follows. Initially, the Director will draft a permit and will share the draft permit with the owner or operator of the nuclear facility. Upon reviewing the draft permit, the owner or operator will determine whether in their view a conflict with a safety requirement established by the Nuclear

Regulatory Commission, the Department of Energy or the Naval Nuclear Propulsion Program exists. If a conflict exists, the owner or operator should communicate the conflict to the NRC, Department or Program and the Director. In all cases, whether a conflict exists or not, the Director should notify the NRC, Department or Program and the owner or operator of the facility that he or she wishes to informally confer regarding the permit. Such interactions should be scheduled, conducted and documented. Where a conflict is identified, the Director would make a site-specific BTA determination.

F. What are example permit conditions and compliance monitoring for impingement mortality?

As previously discussed, the owner or operator must comply with BTA standards as soon as practicable on a schedule of requirements established by the Director. EPA did not specify dates by which the BTA standards for impingement mortality must be met because the specific method of compliance with the BTA standards for impingement mortality is tied to the determination of BTA requirements for entrainment. Further discussion of this alignment of compliance deadlines is provided in Section A. Today's final rule provides for several methods of compliance with the BTA for impingement mortality. This section discusses each of the methods for compliance, how they follow from the permit application requirements at § 122.21(r), and any minimum monitoring and reporting requirements associated with each method.

1. Closed-Cycle Recirculating System

In this method of compliance, an existing facility must operate a closed-cycle recirculating system as defined at § 125.92(c). The facility would indicate the choice to use this compliance method under § 122.21(r)(6) in its permit application. As specified in § 122.21(r)(1), the facility would need to submit § 122.21(r)(9) through (13), if it exceeds 125 mgd AIF and these requirements are not waived by the Director. The information still required at § 122.21(r)(2) to (8) is considerably less burdensome. The monitoring must be representative of normal operating conditions, and must include measuring cooling water withdrawals, make-up water, and blowdown flows. The facility must monitor actual intake flows at a minimum frequency of daily, or may monitor the representative cycles of concentration at a minimum frequency of daily. These monitoring data would be used by the Director to determine that make-up and blowdown flows have been minimized. The owner or operator would submit these data with their existing DMR or equivalent state report. Facilities complying using closed-cycle cooling are not subject to biological compliance monitoring unless otherwise specified by the Director (see § 125.96(c)).

2. 0.5 Feet per Second Through-Screen Design Velocity

In this method of compliance, the facility must operate a cooling water intake structure that has a maximum design through-screen intake velocity of 0.5 feet per second. The facility must submit information under § 122.21(r) to the Director that demonstrates that the maximum design intake velocity as water passes through the structural components of a screen measured perpendicular to the screen mesh could not exceed 0.5 feet per second. The maximum velocity must be achieved under all conditions, including during minimum ambient source water surface elevations (based on BPJ using hydrological data) and during periods of maximum head loss across the screens or other devices during normal operation of the intake structure.

EPA notes a cylindrical wedgewire screen, in general, is designed for 0.5 feet per second. In Phase II, EPA pre-approved wedgewire screens under specific operational conditions. Today's final rule simplifies the demonstration requirements for a facility employing cylindrical wedgewire screens to that of demonstrating the maximum design through-screen velocity is 0.5 feet per second. As another example, a facility may have pumping and piping constrictions that physically limit the design intake velocity to less than 0.5 feet per second. The Director may choose to establish permit conditions that address the physical limitations of the intake, such as requiring a pump be removed from service, or that only one of two (redundant) pumps may operate at any time. Facilities choosing to comply under this section do not have monitoring requirements under this section.

3. 0.5 Feet per Second Through-Screen Actual Velocity

This method of compliance is similar to the design velocity alternative discussed above, except that the intake's maximum design velocity can exceed 0.5 fps, as long as the intake is operated such that the actual, measured velocity does not. As an example, a facility may have originally been constructed with a maximum design intake of 1.0 feet per second, but now, because it has retired generating capacity but not pumps, may only withdraw cooling water such that the actual intake velocity at the intake never exceeds 0.5 feet per second. This would constitute compliance with the impingement mortality standard. The maximum velocity must be achieved under all conditions, including during minimum ambient source water surface elevations (based on BPJ using hydrological data) and during periods of maximum head loss across the screens or other devices during normal operation of the intake structure.

Monitoring the velocity at the screen face or immediately adjacent to the screen face must be conducted at a minimum frequency of daily. Monitoring of the approach velocity does not meet this requirement. However, in lieu of velocity monitoring at the screen face, the owner or operator may calculate the through-screen velocity using intake water flow, water depth, and the screen open area. EPA is requiring this point of measurement to ensure that fish are actually able to swim away (not into an embayment from which they cannot escape) from the location within the intake structure at which they are most susceptible to being impinged.

Under today's final rule, the Director may authorize the facility to exceed the low velocity compliance alternative for brief periods for the purpose of maintaining the cooling water intake system, such as backwashing the screen face. In this compliance option, facilities are not subject to biological compliance monitoring unless otherwise specified by the Director (see § 125.96(c)).

4. Existing Offshore Velocity Cap

In this method of compliance, facilities will submit information under § 122.21(r) that they operate an offshore velocity cap that meets the definition at § 125.92(v) and that was installed prior to the effective date of this rule. The definition of offshore velocity cap includes the requirement that the velocity cap be located a minimum of 800 feet offshore. The velocity cap must include devices to exclude marine animals, such as bar screens. The velocity cap must be designed to change the direction of water withdraw from vertical to horizontal, thereby creating velocity patterns that can be sensed and trigger an avoidance response by fish and other aquatic organisms. Intake flow must be monitored at a minimum frequency of daily. This information will confirm the intended velocity patterns are created. In this compliance option, facilities are not subject to biological compliance monitoring unless otherwise specified by the Director (see § 125.96(c)).

EPA notes that facilities choosing to construct a velocity cap at an offshore location after the effective date of this rule would use compliance options § 125.94(c)(6) (Systems of Technologies as the Site-specific BTA for Impingement Mortality) or § 125.94(c)(7) (Impingement Mortality Performance Standard).

5. Modified Traveling Screens

In this method of compliance, a facility must first operate a modified traveling screen that meets the definition at § 125.92(s). The definition identifies and requires those features of a traveling water screen that provide for an appropriate level of fish protection: collection buckets (or equivalent) to minimize turbulence to aquatic life; guard rails or barriers to prevent loss of fish from the collection system; screen panel materials such as smooth woven mesh, drilled mesh, molded mesh, or similar materials to protect fish from descaling; continuous or near-continuous rotation of screens and operation of collection equipment to recover impinged fish as soon as practical; low pressure wash or vacuum to remove collected organisms from the screens; fish handling and return with sufficient water flow to return fish directly to the source water in a manner that does not promote predation or the re-impingement of the fish, or a large vertical drop. EPA intends for this definition to generally include modified Ristroph screens (including Geiger screens, Beaudrey WIP screens, and Hydrolox screens), dual flow screens, and rotary screens.

Modified traveling screens with a fish return and handling system is the technology basis for the impingement mortality standard, therefore the EPA fully expects biological monitoring of a properly designed, built, and operated modified traveling screen would consistently be able to meet the impingement mortality performance standard. If EPA were to simply set a performance standard based on the numeric performance levels achievable by modified traveling screens, a facility would have to conduct continual biological monitoring to demonstrate compliance. A far more efficient way to demonstrate compliance would be for facilities to optimize the operation of their technologies for their site-specific conditions and identify the conditions that distinguish proper operation at their facility. The optimized operation of the technology would be largely demonstrated through the biological data collection and studies required in the permit application at § 122.21(r)(4) and (6)(i), including an *impingement technology performance optimization study*. Biological data collection should follow the sampling protocols described in section7 below.

The optimized operation documented by the *impingement technology performance optimization study* will result in more than just meeting the impingement mortality standard, and results in a facility achieving the best possible performance.[93] The biological data collection and analysis in the *impingement technology performance optimization study* will identify the operating conditions that result in optimized performance, such as fish sluicing spray pressures, rotation speed and frequency of the screens, angle of the fish sluicing sprays, fish return trough water flows, and fish return trough location.[94] The Director will then establish these operating conditions as permit conditions, along with an equipment inspection condition to assure proper functioning of the technology. As long as the permit conditions are met, the EPA does not expect any biological compliance monitoring will be required, unless otherwise specified by the Director, for example, for the protection of shellfish or fragile species (see § 125.96(c)). Note that EPA does not intend for facilities to install closed-cycle cooling solely for the purpose of meeting the IM requirements.

6. Systems of Technologies as the BTA for Impingement Mortality

In this method of compliance, a facility must demonstrate a system of technologies is employed that will meet the impingement mortality standard. This option will allow a facility the flexibility to choose the systems approach of technologies, management practices, and operational measures it will use to demonstrate compliance, including but not limited to flow reductions, intake location, behavioral deterrents, unit closures, seasonal operations, and newly installed velocity caps. Like the compliance option for modified traveling screens, the optimized operation of the system of technologies will be largely demonstrated through the biological data collection and studies required in the permit application at § 122.21(r)(4) and (6)(ii). However, the analysis and studies for combining the performance of varied technologies is more involved.

If the system of technologies includes credit for reductions in the rate of impingement by the system, the *impingement technology performance optimization study* required at § 122.21(r)(6)(ii) will provide an estimate of those reductions including relevant supporting documentation. The estimated reductions in rate of impingement must be based on a comparison of the facility's system to a once-through cooling system with a traveling screen whose point of withdrawal from the surface water source is located at the shoreline of the source waterbody. EPA expects Phase II facilities will use information already collected as part of their *calculation baseline* (69 FR 41594, July 9, 2004). In addition, the study must include two years of biological data collection demonstrating the rate of impingement resulting from the system. For this demonstration, data collection must be conducted no less frequently than monthly. The Director may establish more frequent data collection or a longer period of study.

If the system of technologies includes credit for reductions in impingement mortality already obtained at the facility, the study must include two years of monthly biological data collection demonstrating the level of impingement mortality the optimized system achieves. Biological data collection must be representative of the impingement and the impingement mortality at the intakes and should follow the sampling protocols described in section 7 below. The *impingement technology performance optimization study* must provide a description of any sampling approach used in measuring impingement mortality, including a taxonomic identification to the lowest taxon possible of all organisms to be sampled; the method in which naturally moribund organisms are identified and taken into account; and the method in which mortality due to holding times is taken into account. In addition, the study must describe how the location of the cooling water intake structure in the waterbody and the water column are accounted for in the sampling locations. EPA requires the entrapment of organisms, as well as organisms that are carried over the screen, to be counted as impingement mortality.

If the system of technologies specifically includes flow reduction to reduce impingement, the *impingement*

[93] As demonstrated by the numerous studies included in the record for today's final rule, many facilities are able to achieve less than 10 percent impingement mortality, a performance level comparable to the impingement mortality of closed-cycle cooling. Merely requiring facilities to achieve a numerical performance standard through modified traveling screens creates disincentives to perform better.

[94] EPA also requires the entrapment of organisms, as well as organisms that are carried over the screens, to be counted as impingement mortality.

technology performance optimization study must include two years of intake flows, measured daily, as part of the demonstration, and must describe the extent to which flow reductions are seasonal or intermittent. The rule clarifies that credit for flow reductions must result from actual reductions in flow, therefore the AIF will be used as a point of comparison, and not the DIF. The study must document how the flow reduction results in reduced impingement, and how the reduction in impingement has reduced the site-specific impingement mortality. Today's final rule at § 125.98(f)(3)(iii) further clarifies that credit in reduced impingement or impingement mortality resulting from unit closures will be valid for a period of 10 years.[95] This is also reflected in permit application requirements for an owner or operator planning to retire the facility in the current permit term at 40 CFR 122.21(r)(1)(ii)(F), or in the following permit cycle at 40 CFR 122.21(r)(1)(ii)(G).

The Director must determine the system of technologies, management practices, and operational measures that is the best technology available for impingement reduction at the site. As the basis for the Director's determination, the facility must demonstrate that the system of technology has been optimized to minimize impingement mortality of all non-fragile species. In addition to the *impingement technology performance optimization study,* the Director may also use the biological source water characterization and/or the entrainment characterization studies in the permit application. EPA expects the Director's decision will be informed by comparing the impingement mortality data under § 122.21(r)(6)(ii) to the impingement mortality performance standard that would otherwise apply under § 125.94(c)(7).

In addition, the *impingement technology performance optimization study* requires documentation of the percent impingement mortality reflecting optimized operation of the total system of technologies, operational measures, and best management practices and all supporting calculations. The following example illustrates how these provisions will adjust for flow, location, and other technologies in demonstrating the IM performance for a system of technologies.

The example uses values that simplify the calculations to better illustrate the adjustments, and are not intended to reflect values that EPA expects at any facility. To simplify the example further, the facility has only fish and does not have shellfish in its source waters. EPA has chosen a hypothetical facility that examined each change in a separate study.[96] The hypothetical facility intake is located at a submerged offshore location, has an acoustical deterrent, and installed variable speed drives. For the purposes of this example, the facility has completed sampling at the forebay for two years as part of § 122.21(r)(4) and (6). During the most recent 12 months, the counts of non-fragile species totals 40,000 impinged fish. During the 24-hour holding period following each monthly sample collection, the total fish that died were counted, for a total of 12,000 dead fish for the preceding 12 months. The facility then calculated the average IM for the preceding 12 months at 30 percent as follows:

$$\% \text{ IM} = \frac{\text{(impinged fish that are killed)}}{\text{(total number of impinged fish)}} \times 100$$

$$= (12{,}000) / (40{,}000) \times 100$$
$$= 30\ \%$$

To adjust the observed percent IM for a submerged offshore location and acoustical deterrent, the facility first extracts information from its previously conducted studies related to performance and calculation baseline. Alternatively, the facility could conduct a performance study during the same two year period in which it conducts its biological data collection as part of the permit application requirements at § 122.21(r). For the submerged offshore location adjustment, fish density and flow data show the offshore location reduces the rate of impingement for all species by 4,000 fish annually. For the acoustical deterrent, performance data show a reduction in the rate of impingement of fish by 11,000 organisms annually. For purposes of this example, assume none of the 15,000 fish are assumed to contribute to further mortality; in other words, all of the fish that avoided impingement in the first place survive. Therefore, the facility has reduced impingement by 15,000 fish (*i.e.,* sum of both submerged offshore location and acoustical deterrent). The facility then takes credit for this reduction by adding the forgone impingement to the denominator of the percent IM calculations as follows:

$$\% \text{ IM} = \frac{\text{(impinged fish that are killed)}}{\text{(total number of impinged fish)}} \times 100$$

$$= (12{,}000) / (40{,}000+15{,}000) \times 100$$
$$= 22\ \%$$

[95] Because a permit may be administratively continued or may not be issued every 5 years, EPA has specified 10 years rather than two permit cycles to avoid facilities from taking credit for a unit closure that potentially occurred decades prior.

[96] EPA recognizes that facilities often examine the combined effect of two or more technologies (e.g., deterrents and offshore location) within a single study. In applying these provisions, the facility could use the outcomes associated with the combined performance of multiple technologies, but this would result in permit conditions that would also be combined.

In summary, calculating percent IM at the forebay yields a 30 percent IM, and then applying the performance for existing technologies shows the effective percent IM is actually 22 percent. Next, to adjust for the variable speed drives, the facility has determined from flow monitoring that the volume of cooling water flow has been reduced by 11 percent. In this example, assume the flow reduction does not vary considerably each month. The volume of reduced flow multiplied by the density of fish near the intake is calculated each month for 12 months, and the facility projects that the reduced flow excludes an additional 8,000 fish from impingement each year. Then the facility would apply the reduction in annual counts of impinged fish to the denominator, as follows:

$$\% \text{ IM} = \frac{\text{(impinged fish that are killed)}}{\text{(total number of impinged fish)}} \times 100$$

$$= (12{,}000) / (40{,}000+15{,}000+8{,}000) \times 100$$
$$= 19\%$$

Thus, the facility's site-specific system of technologies including optimized operation of acoustical deterrents has a total system performance of 19 percent annual impingement mortality. This example is intended to illustrate how facilities would obtain credit for existing technologies in a systems approach. While this example includes acoustical deterrents, it does not imply that acoustical deterrents are an appropriate technology for all facilities. EPA expects a facility will use the required two years' worth of monthly biological data collection and studies to conduct a similar analysis for each month. The minimum required data collection and studies will result in annual average performance calculations for 12 consecutive months. The facility will use this information as part of its demonstration to the Director.

If the Director determines the system of technologies, management practices, and operational measures is the best technology available for impingement reduction at the site, the Director will establish specific operating conditions as permit conditions, along with appropriate equipment inspection conditions to assure proper functioning of each technology. For example, a system with acoustical deterrents would likely have permit conditions related to frequency of tones, volume, location, and frequency of operation of the acoustical deterrents. The Director will also establish monitoring requirements for intake flow and velocity where such measures are an important part of the system of technologies, such as the case of variable speed drives. For example, a system that includes seasonal flow reductions would likely have permit conditions for flow monitoring. As long as the permit conditions are met, the EPA does not expect any biological compliance monitoring will be required, unless otherwise specified by the Director (see § 125.96(c)).

7. Impingement Mortality Performance Standard

In this method of compliance, facilities are required to monitor to demonstrate compliance with the impingement mortality performance standard at § 125.94(c)(7) by demonstrating a 12-month average mortality of 24 percent or less. The facility is required to monitor at a minimum frequency of monthly, unless a greater frequency is specified by the Director. For each monitoring event, the facility would determine the number of non-fragile organisms that are collected or retained on sieve with a maximum spacing of 0.56 inches (*i.e.,* that are impinged [I]), and the number that die after impingement (*i.e.,* impingement mortality [IM]). The facility must establish a post-impingement holding period of 18 to 96 hours otherwise specified by the Director. Under the definition at § 125.92(b), *all life stages of fish and shellfish* excludes specified nuisance species from the totals for both impingement and impingement mortality. Also, as defined at § 125.92(q), *latent mortality* means the delayed mortality of organisms that were initially alive upon being impinged or entrained but that do not survive the delayed effects of impingement and entrainment during an extended holding period. Delayed effects of impingement and entrainment may be due to stresses that include but are not limited to temperature change, physical stresses, and chemical stresses. The manner in which latent mortality is counted must be identified in the Entrainment Characterization Study at § 122.21(r)(9), and must also be counted in the *Impingement mortality performance standard* at § 125.94(c)(7). Fish that are included in any carryover from a traveling screen or removed from a screen as part of debris removal must be counted as impingement mortality. Fish that are entrapped by the cooling water intake system must be counted as impingement mortality.

The 12-month average of impingement mortality is calculated as the sum of total impingement mortality over 12 months divided by the sum of the total impingement over the same 12 months, as shown by the following equation:

$$\% \, IM = \left(\frac{IM}{I}\right) \times \, 100$$

Note that this equation would be applicable to calculating the annual average for the previous 12 months. Although facilities will be conducting biological monitoring monthly (or more frequently) and reporting that data in their discharge monitoring reports, facilities are not required to meet a monthly impingement mortality performance standard. Therefore, in this equation, *IM* is the sum of all impingement mortality over the course of the previous 12 months, and *I* is the sum of all impinged fish for the previous 12 months. If the facility's calculated annual average percentage impingement mortality is less than the 12-month average performance standard, it will be deemed to be in compliance with the 12-month average performance standard.

In establishing the monitoring requirements, EPA expects any approved monitoring protocols will consider the entire daily and (where appropriate) tidal cycles over which data collection should occur. Typically, facilities have collected impingement samples continuously for 6 or 8 hours and repeated this cycle to cover an entire 24-hour period. Stratifying collection in this manner allows an analysis of the diel variation exhibited by many aquatic organisms, which may be important. EPA also expects the approved monitoring protocols will ensure that sampling occurs during periods of representative intake flow and not during periods of non-peak flow or scheduled outages.

The ideal point to measure impingement mortality is the location where organisms are returned to the waterbody. However, for ease of sampling and access, EPA envisions that most facilities will collect samples from the fish return system(s) at some point before the fish return discharge point. According to the studies in EPA's database, EPA envisions that facilities will either (1) divert some or all of the flow from the fish return into a fish collection and holding area, or (2) place a net or basket fitted with 3⁄8-inch mesh spacing in the fish return and collect and transfer the retained organisms to a holding tank. While nearly all studies in the record report the use of 3⁄8-inch mesh spacing, as discussed below, the final rule allows the use of other sieve and mesh spacings with a 0.56 inch maximum opening. A facility will handle the organisms in the collection device as little as possible and transfer them to a holding area with conditions as close as practicable to the source water. The facility will count the number of organisms in the holding area and subsequently hold the sample using proper technique [97] to maintain the health of the collected organisms.[98] At a period of 18 to 96 hours after the initial collection, the facility will count the number of dead organisms and determine the percentage of organisms that died in comparison to the total number of organisms measured initially. Any organisms not collected by the fish handling and return system, such as entrapped organisms, organisms in the carryover of a traveling screen, or organisms collected by a high-pressure wash and sent to debris bins, will be counted as 100 percent impingement mortality. The facility will keep records of this information and compare its result to the impingement mortality performance standard at § 125.94(c)(7).

As explained in Section VI, the impingement mortality restrictions in the final rule are based on the operation of a modified traveling screen with a fish return. Because EPA wants to ensure that a facility's monitoring plan is consistent with the technical basis for today's requirements, EPA is requiring facilities to monitor impingement mortality using a sample that has been passed through a sieve or net with no more than 0.56 inches maximum opening, so that only organisms that do not pass through this mesh size are counted.[99] In doing so, facilities would retain (and therefore count) only organisms that would have been impinged on a 3⁄8″ mesh screen, which was the technological basis used for developing the impingement mortality performance standard.[100] Facilities could similarly apply a ''hypothetical net'' in that they could elect to count only organisms that would not have passed through a net with mesh openings less than 0.56 inches. For example, a facility that uses a fine-mesh screen of 0.5 mm or diverts the flow directly to a sampling bay will need to count only organisms that remain if the flow passed through a net, screen, or debris basket fitted with 3⁄8-inch mesh spacing. EPA further expects the impingement mortality restrictions could be applied to other fish protection technologies and provides a compliance route for future technologies that are better performing.

In today's rule, EPA is including provisions for reduced biological monitoring. EPA determined that monthly monitoring at a minimum is appropriate for at least the first full permit term. In permit terms subsequent to the first permit issued under today's rule, the owner or operator may request the Director to reduce monitoring requirements under § 125.95(c). EPA expects the Director would reduce monitoring requirements as appropriate, if the facility demonstrates that its operational and biological conditions have remained the same. Given that the source waterbody may change over time (including hosting different or increased numbers of individuals or species), the biological characterization required at § 122.21(r)(4) including two years of data serves to alert interested parties as to the status of the waterbody and any changes in the biology of the waterbody. Under the compliance option (7) impingement mortality performance standard, EPA expects that as new technologies are successfully demonstrated, in subsequent permits facilities would request less frequent monitoring, or be able to incorporate such technologies in a permit application choosing a § 125.94(c)(6), system of technologies, demonstration. Once the Director has determined the technology is fully demonstrated for that site, the facility would therefore reduce their biological data collection to the minimum required by the permit application at § 122.21(r) and any monitoring the Director determines to be appropriate for verifying permit operating conditions.

8. Additional Measures

Sections § 125.94(c)(8) and (9) provide the Director discretion to require additional measures to protect shellfish and fragile species. An example of shellfish protection measures is a barrier net, including seasonal deployment of such nets. An example of additional protection measures for fragile species is an acoustical deterrent system.

9. Summary

The following Exhibit VIII–4 summarizes the monitoring requirements for impingement mortality by compliance approach alternative. The Director has the discretion to require additional monitoring under § 125.96(c) and (d). Since all permits must have requirements for visual inspections, these are not included in the exhibit.

[97] EPA recognizes that at present, there are no standard methods for conducting impingement and entrainment studies and that there can be variability in designing a sampling plan between sites. However, some elements should be incorporated into any sampling plan, as outlined in DCN 10–6708.

[98] Facilities that divert the flow directly would similarly pass the flow through a net or debris basket fitted with 3⁄8-inch mesh spacing or would count only organisms that would have been collected with such a basket or net.

[99] For a discussion of how EPA has changed its view of screen mesh size, see Section III of the proposed rule (76 FR 22188, April 20, 2011). EPA recognizes that smaller organisms that previously would have passed through a screen and been entrained might be ''converted'' by a fine mesh screen to an impinged organism; because organisms size would affect the rate of mortality, EPA has chosen not to rely on definitions of impingement and entrainment based on a physical process, but instead to define impingement mortality and entrainment mortality based on organisms sizes.

[100] EPA's analysis of impingement survival rates is based on data from facilities with 3⁄8″ mesh screens; the performance standard may be applied differently at facilities with smaller mesh size. Therefore, these standards do not provide a disincentive to facilities from using finer-meshed screens (i.e., screens with a mesh opening smaller than 3⁄8 inch) on their traveling screens. As long as the organisms that are large enough to have been impinged on a coarse mesh screen achieve the required survival rates, the facility will be considered to meet the impingement mortality requirements.

EXHIBIT VIII–4—SUMMARY OF MONITORING REQUIREMENTS FOR IMPINGEMENT MORTALITY

Compliance approach	Type of monitoring	Frequency
Closed-cycle recirculating system	Intake, makeup and blowdown flows (or cycles of concentration)	Daily.
Velocity (DIF)	None	None.
Velocity (AIF)	Velocity (measured or calculated from flow)	Daily.
Velocity cap	Intake flow	Daily.
Modified traveling screens	TBD [a]	TBD [a].
Systems of Technologies	TBD [b]	TBD [b].
Impingement mortality performance standard	Biological monitoring	Monthly.

[a] Monitoring requirements may vary, depending on the permit-specific operating conditions.
[b] The monitoring requirements are based on the technologies employed. For example, seasonal flow reduction would require flow monitoring.

G. What monitoring is required for entrainment?

Where the Director establishes entrainment controls, the Director is required to establish monitoring requirements. The final rule requires that the permit application studies at § 122.21(r) be submitted for each permit renewal. For facilities that withdraw 125 mgd AIF, EPA expects that the Director will use these studies, including the Source Water Baseline Biological Characterization Data at § 122.21(r)(4) and the Entrainment Characterization Study at § 122.21(r)(9), as a basis for any monitoring requirements for entrainment. To facilitate the determination of entrainment requirements for facilities below 125 mgd AIF, a Director may require the owner or operator to submit some or all of the study requirements at § 122.21(r)(9) through (13) or variations thereof. The Director may require additional monitoring necessary to demonstrate compliance with § 125.94(d), additional measures to protect Federally-listed endangered and threatened species and designated critical habitat requirements under § 125.94(g), interim standards under § 125.94(h), and any more stringent standards under § 125.94(i).

Under § 125.96(d), existing facilities with new units are required to conduct compliance monitoring to demonstrate flow reductions consistent with the requirements of § 125.94(e)(1), or equivalent impingement and entrainment reductions. The Director may establish flow monitoring or monitoring of cycles of concentration as discussed in Section F. Such measures will be used to document that the facility has minimized make-up and blowdown flows.

For facilities complying under § 125.94(e)(2), the frequency of monitoring will be determined by the Director and will vary depending on the facility's chosen method of compliance.

To meet requirements under § 125.94(e)(2), facilities must measure AIF to establish a site-specific baseline without any new technologies or employing additional operational measures. The facility must also measure the density of entrainable organisms (E_D) at a proximity to the intake that is representative of the entrainable organisms present without the cooling water intake structure. Samples will be collected over a 24-hour period to monitor each species as required by the Director. Samples will be collected no less than biweekly during the primary period of reproduction, larval recruitment, and peak abundance identified during the Source Water Baseline Biological Characterization Data required under § 122.21(r)(4). Samples will be representative of the cooling water intake when the structure is in operation. In addition, sufficient samples must be collected to allow for calculation of 12-month average entrainment levels. The sampling will measure the total count of entrainable organisms or density of organisms, unless the Director approves of a different metric for such measurements. If the abundance varies seasonally, the Director may require several measurements of entrainment through the year, from which a 12-month average can be calculated.

For the purpose of today's rule, *entrainable* is defined as any organism that passes through a sieve with a maximum opening of 0.56 inches. As discussed in Section VI, this would avoid any confusion as to which organisms are subject to which standards (i.e., requirements for IM or requirements for E). The regulation specifies that the sieve used for calculating impingement must be the same sieve used for calculating entrainment, so all organisms are accounted for. Facilities can also monitor the latent entrainment mortality in front of the intake structure. Entrainable organisms passing through the cooling water intake structure are to be counted as 100 percent entrainment mortality unless the facility demonstrates to the approval of the Director that the mortality for each species is less than 100 percent.

In addition, facilities must monitor the AIF for each intake. The AIF must be measured at the same time as the samples of entrainable organisms are collected.

The following equation illustrates how to calculate a baseline level of entrainment (E_B):

$$E_B = E_D \times AIF$$

Performance commensurate with a closed-cycle recirculating system (E_{CCRS}) can therefore be determined by reducing E_B by the percentage of flow reduced through the use of a closed-cycle cooling system. For example, a facility withdrawing make-up water from a freshwater source (as described above, would achieve a reduction of 97.5 percent) will calculate its performance as follows:

$$E_{CCRS} = (E_B) \times (100 - 97.5) \div 100$$

The resulting value, E_{CCRS}, is the required level of entrainment performance (as measured by entrainment mortality). The facility could implement any combination of flow reduction, technologies, and operational measures to meet the required level of entrainment performance. For example, a facility withdraws 200 mgd AIF from a freshwater river. The annual average entrainment density in the proximity of the intake structure is 6,400 organisms per 100 cubic meters withdrawn.

$$E_B = E_D \times AIF$$

$$6{,}400 \text{ organisms}/100\text{m}^3 \times (100\text{m}^3/26{,}417 \text{ gallons}) \times 200{,}000{,}000 \text{ gallons per day}$$

$$= 48 \times 10^6 \text{ organisms per day}$$

The maximum entrainment mortality for a closed-cycle cooling system is thus

$$E_{CCRS} = (E_B) \times (100 - 97.5) \div 100$$

$$= (48 \times 10^6 \text{ organisms per day}) \times (100 - 97.5) \div 100$$

$$= 1.2 \times 10^6 \text{ organisms per day.}$$

The minimum required level of performance for demonstrating entrainment mortality at a comparable level (E_C) to a closed-cycle cooling system is the level corresponding to 90 percent[101] of the reduction that a facility with a closed-cycle cooling system could achieve:

$E_C = (E_B) \times (100 - (97.5 \times .9)) \div 100$
$= (48 \times 10^6 \text{ organisms per day}) \times (100 - (97.5 \times .9)) \div 100$
$= 5.88 \times 10^6$ organisms per day.

The Director may require additional monitoring necessary to demonstrate compliance with § 125.94(d), endangered species requirements under § 125.94(g), interim standards under § 125.94(h), and any more stringent standards under § 125.94(i).

In addition, all facilities will either conduct visual inspections or employ remote monitoring devices when the cooling water intake structure is in operation. The facility will conduct such inspections at least weekly to ensure that any technologies installed to comply with § 125.94 are maintained and operated to ensure that they will continue to function as designed. EPA is aware that for some facilities, this requirement could pose a feasibility challenge (for example due to ice cover in the winter season, inability of divers to see through more than a few inches of water, or certain intakes in deep water). The rule, therefore, authorizes the Director to establish alternative procedures. See § 125.96(e).

H. What reports am I required to submit?

1. Status Reports

If the Director establishes a compliance schedule, the Director will also establish any status reporting requirements. These reports may include updates on biological monitoring, technology testing results, construction schedules, or other appropriate topics and serve as milestones for the facility and the Director to evaluate the progress of the facility in meeting BTA. See §§ 125.94(b) and (d) and 125.97(b).

2. Monitoring Reports

The required reports for monitoring activities are similar to requirements that are already in NPDES permits for effluent discharges. EPA expects such reports to be included with the Discharge Monitoring Reports (DMRs) or equivalent state reports. Facilities would report any monitoring, demonstration, and other information required by the permit sufficient to determine compliance with the permit requirements established under § 125.94, as well as any other monitoring requirements specified in the permit. See 40 CFR 125.97(a).

Entrainment requirements will be determined on a site-specific basis by the Director. For facilities that are required to install entrainment controls, EPA expects that these facilities would generally conduct ongoing flow (or other) monitoring as verification that entrainment has been reduced. See § 125.96(b) and (c). However, the Director may require facilities to report entrainment monitoring and analysis, including:

- The compliance measurement location.
- A description of the flow monitoring procedure.
- Documentation of flow reductions.
- Any other monitoring requirements specified in the permit.

The report must include any monitoring and analysis required as part of additional measures for threatened and endangered species, shellfish, or fragile species as established by the Director. Further, your report will include documentation of cooling water that is process water, gray water, waste water, reclaimed water, or other water reused as cooling water in lieu of water obtained by an intake. The Director will evaluate these reports for compliance with permit requirements as appropriate.

3. Annual Certifications

Today's rule requires a facility to submit an annual certification statement signed by the responsible corporate officer. See § 125.97(c). In most cases, the statement would indicate the information from the previous statement is still pertinent. If modifications were made to the facility that impacts cooling water withdrawals or operation of the cooling water intake structures, the statement would indicate such, and the facility would submit revisions to the information required in their permit application at § 122.21(r).

4. Other Reporting

In addition, EPA notes that supplemental reporting may be required under the ESA as part of any incidental take statement or permit (50 CFR 402.14(i)) or a section 10 permit (50 CFR 222.307) that is issued by the United States Fish and Wildlife Service or the National Marine Fisheries Service to ensure compliance with the Endangered Species Act.

I. What records will I be required to keep?

As described at § 125.97(d), facilities are required to keep all permit applications, status, monitoring, and annual reports and related supporting information and materials at least until the subsequent permit is issued. Facilities might wish to keep records for a longer period to maintain a complete regulatory history of the facility. For example, existing source water biological studies submitted with a facility's permit application could contain data that has been collected in the past 10 or more years. When the Director has approved a request for reduced information collection in the permit application, the rule requires that records of submissions that are part of a previous permit application be kept until the subsequent permit is issued. See § 125.95(e). Records supporting the BTA determination for entrainment must be kept until such time as the Director revises the determination. The Director may establish additional record-keeping requirements in the permit, such as additional records documenting compliance monitoring, data collection, or more frequent reports.

Facilities must also keep records of all data used to complete the permit application and show compliance with the requirements of § 125.94, any supplemental information developed under § 125.95, and any compliance monitoring data submitted under § 125.96. The Director may require that these records be kept for a longer period.

J. What are the respective Federal, State, and Tribal roles?

Today's final rule affects authorized State and Tribal NPDES permit programs. Under 40 CFR 123.62(e), any existing approved section 402 permitting program must be revised to be consistent with new program requirements within one year from the date of this promulgation, unless the NPDES-authorized State or Tribe must amend or enact a statute to make the required revisions. If a State or Tribe must amend or enact a statute to conform to today's final rule, the revision must be made within two years of this promulgation. States and Tribes seeking new EPA authorization to implement the NPDES program must comply with the requirements when authorization is approved. This final regulation does not alter State authority under section 510 of the CWA.

In addition to updating their programs to be consistent with today's final rule,

[101] The 90 percent metric is required in Phase I, and adopted here because new units are subject to requirements similar to the Phase I requirements. Phase I, at 40 CFR 125.86 specifies, ''reduced both impingement mortality and entrainment of all life stages of fish and shellfish to 90 percent or greater of the reduction that would be achieved through § 125.84(b)(1) and (2).''

States and Tribes authorized to implement the NPDES program are required under NPDES State program requirements to implement the cooling water intake structure requirements of subpart J following promulgation of the final regulations. The permit requirements in this final rule must be implemented upon the first issuance or reissuance of permits following promulgation. Duties of an authorized State or Tribe under this regulation are described throughout this section and include reviewing permit application materials, determining appropriate requirements, reviewing monitoring and reporting data, and assessing whether a facility is complying with the final rule's requirements.

EPA recognizes that some States have invested considerable effort in developing and implementing section 316(b) permits. This final regulation at § 125.98(b) and (g) allows the Director flexibility where there are ongoing permit proceedings or where a BTA determination has already been made based on substantially the same information required at § 122.21(r).

EPA will implement these requirements where States or Tribes are not authorized to implement the NPDES program.

K. Protection of Endangered and Threatened Species and Designated Critical Habitat

1. Existing Requirements Under Section 9 of the Endangered Species Act

The ESA imposes duties not just on Federal agencies but also on other entities. Section 9 of the ESA specifically provides that it is unlawful for any person to ''take'' any endangered species of fish or wildlife except under defined circumstances. The Services (National Marine Fisheries Service or U.S. Fish and Wildlife Service) may provide an exemption to the prohibition on take in one of two ways. Take may be permitted under section 10 of the ESA (16 U.S.C. 1539) or the Services may provide an exemption for take that is incidental to otherwise legal activity through a statement that is included with the Services' biological opinion developed during Federal agency consultation. (16 U.S.C. 1536(o)) The incidental take statement specifies the terms and conditions necessary to implement reasonable and prudent measures which minimize incidental take.

Nothing in today's rule changes the existing, independent obligations of the facilities subject to this rule under section 9 of the ESA. Unless exempted by an incidental take statement or section 10 permit, facilities have been prohibited from taking (for example, harming or killing) endangered species of fish or wildlife. In order to obtain a section 10 permit, the facility would be required to develop a Habitat Conservation Plan (HCP), which is a mandatory component of an incidental take permit application. The HCP must specify the anticipated effects of the proposed taking, how those impacts will be minimized or mitigated, the alternative actions to the taking that the applicant considered, the reasons for not utilizing those alternatives, and other necessary or appropriate measures that the Secretary may require.

2. EPA's Consultation Under Section 7 of the ESA

Under section 7 of the Endangered Species Act, each Federal agency must insure that any action authorized, funded, or carried out by the agency ''is not likely to jeopardize the continued existence of any endangered species or threatened species or result in the destruction or adverse modification of habitat of such species which is determined by the Secretary, after consultation as appropriate with affected States, to be critical. . . .'' 16 U.S.C. 1535(a)(2). In the case of any Federal agency action subject to the ESA that may affect listed species or critical habitat, the Federal agency must consult with the concerned offices with responsibilities under the ESA, specifically NMFS and/or FWS. 50 CFR 402.14(a).

In July 2012, EPA began informal consultation with the NMFS about the proposed section 316(b) regulations. In October 2012, EPA began informal consultation with the FWS. EPA prepared a draft biological evaluation of the effects of this rule on threatened and endangered species and in it concluded that the rule was not likely to adversely affect listed species or designated critical habitat. EPA was unable to obtain the Services' concurrence on EPA's ''not likely to adversely affect'' finding. In June 2013, EPA requested formal consultation with the Services under the Endangered Species Act and with that request submitted a final biological evaluation to the Services. EPA completed consultations with the Services and has included the Services' biological opinion and associated documents in the record for this rulemaking.

Among the organisms potentially subject to impingement and entrainment at cooling water intake structures are those that are listed as threatened and endangered. In addition to impinging or entraining threatened and endangered species, operation of CWISs may also adversely affect their critical habitat. Today's rule includes a number of provisions specifically designed to address incidental take of all federally-listed threatened and endangered species and to insure that the rule is not likely to jeopardize the continued existence of listed species or result in the destruction or adverse modification of critical habitat. These provisions are described below.

The regulatory model adopted by EPA in the Phase I rule and later in the subsequently-withdrawn Phase II rule for large existing power producing facilities provided a structure to address and minimize adverse impacts to threatened and endangered species. EPA's approach required that facilities subject to the 316(b) rules, at the permit application stage of the permitting process must, among other things, identify threatened and endangered species that might be subject to impingement and entrainment in order to ensure that the permitting authority would have the requisite information on which to make a decision about the need for controls to protect threatened and endangered species. See 40 CFR 122.21(r)(4).

The Phase I and Phase II regulations specifically authorized the permit writer (referred to as the ''Director'' in EPA's permitting regulations) to adopt measures designed to protect threatened and endangered species. Thus, for example, EPA's Phase I regulations for cooling water intake structures at new facilities require that, under one of the compliance options, an owner or operator must select and implement impingement and entrainment minimization measures ''if there are threatened or endangered or otherwise protected Federal, State or Tribal species.'' Moreover, the permit writer may require additional impingement and entrainment reduction measures if the permit writer determines that the facility after meeting the required performance standard would ''still contribute unacceptable stress to the protected species, critical habitat of those species or species of concern.'' 40 CFR 125.84(b)(4) & (5).

The Phase II regulation continued the general approach followed in the Phase I regulation for protection of threatened and endangered species. Permit applicants needed to submit the same information on threatened and endangered species required in the Phase I rule. In addition, building on the earlier information requirements, the regulation also would have required facilities selecting and implementing certain of the alternative BTA compliance measures to submit a Comprehensive Demonstration Study that, among other things, characterized impingement and entrainment at the facility. Further, the rule would have required a facility to submit an Impingement Mortality and/or Entrainment Characterization Study that included taxonomic identification, characterization and documentation of current impingement mortality and entrainment of all life stages of fish, shellfish and any species protected under Federal, State or Tribal law (including threatened or endangered species). 69 FR 41687–88, July 9, 2004. In addition, the Phase I and II rules included a requirement for the facility to include in their permit application documentation of any public participation or consultation with Federal or State agencies on impacts of their cooling water intake structure on threatened and endangered species. The regulation then would have required the permit writer to determine appropriate permit requirements and conditions. EPA noted that its existing NPDES permitting regulations reference a number of Federal laws that might apply to Federally-issued NPDES permits, including the Endangered Species Act. 69 FR 41643–44, July 9, 2004.

Threatened and endangered species were important considerations in the proposal to today's rule and were of particular concern to the EPA. The preamble to the proposal reflects at a number of points that, in looking at the benefits of different regulatory options, EPA attempted to assess the benefits to threatened and endangered species. See 76 FR 22174, 22197, 22207. The proposal also noted the importance of obtaining information for the permit writer about potential entrainment reductions. Thus, the proposal would have required certain facilities to develop and submit with their permit application detailed information on their operations as well as an engineering study of the technical feasibility and incremental costs of candidate entrainment mortality control technologies and a detailed discussion of the magnitude of non-water quality benefits. EPA proposed that some facilities would need to submit an Entrainment Characterization Study that included an entrainment mortality data collection plan that would indicate, at a minimum, taxonomic identification, latent mortality identification, documentation of all methods, and quality assurance/quality control procedures or sampling and data analysis appropriate for a quantitative survey. Under the proposal, EPA would also have required peer review of the entrainment mortality data collection plan. Peer reviewers would be selected in consultation with the Director who may consult with EPA and Federal, State, and Tribal fish and wildlife management agencies with responsibility for fish and wildlife potentially affected by the cooling water intake structure(s). Further, facilities with greater than 125 mgd AIF would complete an entrainment study. The entrainment study could include information already collected to meet the Phase II requirements at § 122.21(r)(2)–(r)(4) before those requirements were suspended.

EPA and the Services have completed consultations on the rule. EPA has received the final biological opinion and associated documents from the U.S. Fish and Wildlife Service and the U.S. National Marine Fisheries Service and has included them in the record for the rule. The Services have concluded that the rule is not likely to jeopardize the continued existence of listed species or result in the destruction or adverse modification of designated critical habitat.

3. Final Rule Provisions Related to Threatened and Endangered Species

As noted previously, establishing standards for cooling water intake structures to minimize impingement and entrainment of all aquatic organisms will promote and enhance protection of T&E species. In addition, the rule contains a number of provisions that specifically concern T&E species; these provisions were developed in light of EPA's consultation with the Services and were established by EPA to insure that this rule is not likely to jeopardize listed species or result in the destruction or adverse modification of designated critical habitat. To be clear, the ESA provisions of the rule extend to all listed T&E species, not just fish and shellfish.

The treatment of T&E species in today's rule follows directly from the Agency's longstanding approach as well as from EPA's proposed 2011 rule which indicated the EPA's intention to address protection of T&E species. The rule adopts the identical approach followed in the Phase I and II rules, while adding some refinements to that earlier model which EPA discussed in the proposed rule. First, it adopts the proposed requirements that insure an adequate information base is submitted to the permit writer. As was the case with the Phase I and withdrawn Phase II rule, apprising the permit writer of the presence and extent of T&E species at a facility's intake continues to be an important element of the permit application requirements for existing facilities. While retaining the existing permit application requirement of 40 CFR 122.21(r), EPA has included in today's rule a provision at § 125.95(f) that requires a facility in its permit application to identify all Federally-listed threatened and endangered species and designated critical habitat that are or may be present in the action area. The action area can generally be considered the area in the vicinity of the cooling water intake structure. The evaluation is to be based on information readily available to the facility at the time of the permit application. In addition, the rule requires the largest withdrawing facilities to provide taxonomic identification of species in the vicinity of the intake, thus providing a mechanism for facilities to determine more accurately their potential impact on protected species.

The rule requires that the Director transmit all permit applications to the Services upon receipt. The rule provides the Services with 60 days to review the permit application. This 60 day review takes place prior to the public notice of the State or Tribe's draft or proposed permit. EPA expects that the Services will respond within 60 days and provide to the Director (1) any corrections to the list of Federally-listed threatened and endangered species and critical habitat included in the permit application, (2) any measures that the Services recommend (including monitoring and reporting) for the protection of listed species, including any measures that would minimize any incidental take of listed species, and/or avoid likely jeopardy to a listed species or destruction or adverse modification of critical habitat, and/or (3) notify the State or Tribe that the Service(s) have no corrections to the list of species and critical habitat and/or that the Service(s) do not recommend any control measures. The Services' 60 day review period does not constrain the Director's ability to process the applicant's permit application; however, the Director may not propose/publish the draft permit until the 60 day review period has ended, unless the Director has received the Services' response prior to that time.

In addition, the Services will receive, pursuant to existing regulations at 40 CFR 124.10(c)(1)(iii) and (e), all permit applications, as well as fact sheets or statements of basis (for EPA-issued permits), draft permits, and public notices for all permits. At this stage of the process, the Services will have the opportunity to review the draft permit and other materials and provide any additional input or suggested control measures to address effects to listed species or critical habitat. Together, the existing and new requirements related to transmittal of permitting documents to the Services will ensure that the Services have the opportunity to provide information and recommendations to the permit writer relating to any facility that may affect listed species. This information will be part of the public record for the permitting decision and the Director would be required to consider it as a relevant factor, along with all of the other relevant factors, in deciding what conditions to establish in the permit. Further, as explained in the MOA between EPA and the Services discussed elsewhere in today's notice, EPA will use the full extent of its CWA authority to object to a permit where EPA finds that issuance of the permit is likely to jeopardize the continued existence of a listed species or result in the destruction or adverse modification of designated critical habitat. The rule's requirements insure a full vetting of information and concerns in the permitting process that must be considered by the Director. These requirements, coupled with the EPA's commitment to exercise its oversight authority, insure that today's rule is not likely to jeopardize the continued existence of a listed species or result in the destruction or adverse modification of designated critical habitat.

Among the recommendations that may be made by the Services to the facility and the Director are measures to minimize incidental take. EPA expects that any measures the Services recommend to minimize incidental take will be consistent with ESA regulations and guidances concerning reasonable and prudent measures. As stated in the ESA regulations under 50 CFR 402.14(i)(2), ''Reasonable and prudent measures, along with the terms and conditions that implement them, cannot alter the basic design, location, scope, duration, or timing of the action and may involve only minor changes.'' The Endangered Species Handbook (FWS and NMFS, 1998) explains that: ''Measures are considered reasonable and prudent when they are consistent with the proposed action's basic design (e.g., narrowing of disturbed right-of-way at known species locations), location (e.g., temporary storage of equipment or other materials), scope, duration, and timing. Reasonable and prudent measures and terms and conditions should be developed in coordination with the action agency and applicant, if any, to ensure that the measures are reasonable, that they cause only minor changes to the project, and that they are within the legal authority and jurisdiction of the agency or applicant to carry out.''

Installation of closed-cycle cooling is a major design alteration of a facility involving significant design and construction activities (the range of costs associated with closed-cycle cooling is described elsewhere in today's notice). Because installation of closed-cycle cooling does alter the basic design of a facility and would involve more than minor changes, as described in the Services' regulations and Handbook, EPA does not expect that installation of closed-cycle cooling would be specified as a measure solely for purposes of minimizing incidental take. The final rule at § 125.98(j) provides that nothing in this rule authorizes the take of threatened or endangered species of fish or wildlife. However, the Services may exempt take through an incidental take statement issued pursuant to ESA section 7(o) or a permit under ESA section 10. See 16 U.S.C. 1536 (o) and 16 U.S.C. 1539.

This Clean Water Act rule cannot authorize take and does not purport to do so (nor can NPDES permits authorize take prohibited under the ESA). Accordingly, under § 125.98(b)(1), the permit writer, including EPA, must include, in the 316(b) permit requirements, standard language that states the permit does not authorize the take of Federally-listed threatened and endangered species. In addition, under § 125.96(g) (additional monitoring requirements) and § 125.97(g) (additional reporting requirements),where the Director requires additional measures to protect listed species, monitoring and reporting requirements associated with those measures will be included in the permit.

4. EPA Oversight of State-Issued NPDES Permits To Protect Threatened and Endangered Species

In 2001, the EPA, FWS, and NMFS signed a Memorandum of Agreement (MOA), (66 FR 11202, Feb. 22, 2001) with the objective of enhancing coordination between the agencies and to assist the agencies in executing their respective responsibilities under the Clean Water Act and Endangered Species Act. The MOA reflects, in part, the EPA's longstanding commitment to overseeing the operation of state NPDES programs to ensure protection of endangered species with existing regulatory requirements. The EPA reaffirms its commitment to ensure coordination of the EPA's and Services' programs and appropriate protection of listed species, and EPA will follow the procedures in the MOA in overseeing implementation of this rule.

The MOA committed the EPA to a number of specific actions that are pertinent to today's rule. Under the MOA, EPA committed, when contacted by the Services, to coordinate with the Services and the State/Tribe during the permit development process, in order to ensure that permits will comply with all applicable CWA requirements. One way in which coordination between EPA and the Services is facilitated is through the exchange of information about permits. The MOA facilitates such information exchange, as do EPA's NPDES permit regulations at 40 CFR 124.10, that preceded the MOA. These regulations require the Director to provide public notice and a comment period for draft permits, and to notify persons identified at 40 CFR 124.10(c)(1)(iii) and (iv). Such persons specifically include Federal and State agencies with jurisdiction over fish, shellfish, and wildlife resource and over coastal zone management plans and thus include the U.S. Fish and Wildlife Service and the National Marine Fisheries Service.

EPA's commitment to coordinate effectively with the Services includes following the procedures in section IX.A.6 and 7 of the MOA:

EPA may make a formal objection, where consistent with its CWA authority, or take other appropriate action, where EPA finds that a State or Tribal NPDES permit will likely have more than minor detrimental effect on Federally-listed species or critical habitat.

For those NPDES permits with detrimental effects on Federally-listed species or critical habitat that are minor, it is the intention of the Services and EPA that the Services will work with the State or Tribe to reduce the detrimental effects stemming from the permit. For those NPDES permits that have detrimental effects on Federally-listed species or critical habitat that are more than minor, including circumstances where the discharge fails to ensure the protection and propagation of fish, shellfish and wildlife, and where the State or Tribe and the Services are unable to resolve the issues, it is the intention of the Services and EPA that EPA would work with the State or Tribe to remove or reduce the detrimental impacts of the permit, including, in appropriate cases, by objecting to and Federalizing the permit where consistent with EPA's CWA authority.

EPA will use the full extent of its CWA authority to object to a State or Tribal permit where EPA finds (taking into account all available information, including any analysis conducted by the Services) that a State or Tribal permit is likely to jeopardize the continued existence of any listed species or result in the destruction or adverse modification of critical habitat.

EPA may review or waive review of draft State or Tribal NPDES permits (40 CFR 123.24(d)). EPA will work with the Services through the local/regional coordinating teams to help determine which categories of permits should be reviewed for endangered species concerns. If EPA finds that a draft permit has a reasonable potential to have more than a minor detrimental effect on listed species or critical habitat, and review of a draft permit has been waived, EPA will withdraw this waiver during the public comment period (see 40 CFR 123.24(e)(1)).

The grounds for EPA's exercise of its discretionary authority to object to State or Tribal permits are described in the NPDES regulations at 40 CFR 123.44. These include that the proposed permit fails to comply, or to ensure compliance with, any applicable requirement of this part, for example, that a permit application did not contain information sufficient to demonstrate that the permit will ensure compliance with applicable requirements. See 40 CFR 123.44(c)(1).

If EPA objects to a NPDES permit under the MOA, EPA will follow the permit objection procedures outlined in 40 CFR 123.44 and coordinate with the Services in seeking to have the State or Tribe revise its permit. A State or Tribe may not issue a permit over an outstanding EPA objection. If EPA assumes permit issuing authority for a NPDES permit, EPA will consult with the Service prior to issuance of the permit (as a Federal action) as appropriate under section 7 of the ESA.

While the MOA was adopted by the agencies in the context of NPDES permits for discharges of pollutants, it applies equally to NPDES permits that contain conditions for cooling water intake structures. Moreover, section 316(b) of the CWA accords EPA broad authority to protect waters of the United States from adverse environmental impacts associated with cooling water intake structures, including adverse effects to Federally-listed species and designated critical habitat. In implementing this provision, EPA is authorized to consider costs and benefits of different approaches to minimizing these impacts. The importance of listed species, and accordingly the benefits associated with preventing their extinction, animated Congress's enactment of the Endangered Species Act in 1973. In the case of aquatic organisms that are listed as endangered or threatened, and designated critical habitat, EPA has the authority, and will exercise the full extent of its authority, to object to a permit proposed by a State where EPA finds (taking into account all available information, and giving, as appropriate, substantial weight to the views of the Services) that a State or Tribal permit is likely to jeopardize the continued existence of such species or result in the destruction or adverse modification of such critical habitat. If the State permit is not modified to address EPA's objections, EPA will issue the permit in consultation with the Services. EPA's commitment to use the full extent of its CWA authority to object to permits that are likely to jeopardize listed species or result in the destruction or adverse modification of critical habitat is a safeguard for the protection of listed species and critical habitat. Additionally, where the Service communicates in writing to EPA its conclusion that a proposed State permit is likely to jeopardize the continued existence of a listed species, EPA will, upon request, provide the Service a written response. EPA's commitment to use the full extent of its CWA authority, along with the other provisions of the rule requiring the EPA, the Services, and State Directors to fully consider effects to threatened and endangered species and critical habitat and include appropriate protections in NPDES permits, insures that the rule is not likely to jeopardize the continued existence of listed species or result in the destruction or adverse modification of designated critical habitat.

L. Permits for Existing Facilities Are Subject to Requirements Under Other Federal Statutes

EPA's NPDES permitting regulations at § 122.49 list Federal laws that might apply to the issuance of NPDES permits under the NPDES rules. These include the Wild and Scenic Rivers Act, 16 U.S.C. 1273 *et seq.;* the National Historic Preservation Act of 1966, 16 U.S.C. 470 *et seq.;* the Coastal Zone Management Act, 16 U.S.C. 1451 *et seq.;* and the National Environmental Policy Act, 42 U.S.C. 4321 *et seq.* For a brief description of each of these laws, see § 122.49. The provisions of the Magnuson-Stevens Fishery Conservation and Management Act, 16 U.S.C. 1801 *et seq.,* relating to essential fish habitat might also be relevant. EPA's permit application requirements ensure that FWS and NMFS will have— and other Federal agencies as well, should have—a broader information base from which to make informed decisions. Note also that, in the case of EPA-issued permits, EPA's NPDES permitting regulations specifically require following the requirements of specific Federal laws that may apply to the issuance of NPDES permits.

IX. Cost Development and Economic Impact Analysis

This section summarizes EPA's analysis of the social cost and economic impact for three regulatory options. In addition to today's rule, referred to as the Final Rule, EPA analyzed two other options similar to those options at proposal (see section VI.D Other Options Considered for Today's Final Regulation for more context). The regulatory options can be described as follows:

- Final Rule: Flexible impingement mortality performance standard for existing units based on modified traveling screens with fish returns for all facilities with DIF greater than 2 mgd, closed-cycle cooling or its equivalent for new units for impingement and entrainment, and a national BTA standard that requires a site determination of entrainment BTA for all other existing units at existing facilities;
- Proposal Option 2: Intake flow commensurate with closed-cycle cooling for facilities that have a design intake flow of greater than 125 mgd, flexible impingement mortality limitations based on modified traveling screens with fish returns for all facilities with DIF greater than 2 mgd, and closed-cycle cooling or its equivalent for new units; and
- Proposal Option 4: Flexible impingement mortality limitations based on modified traveling screens for all facilities with DIF greater than 50 mgd, closed-cycle cooling or its equivalent for new units, and a site-specific determination of entrainment BTA for all other facilities and for impingement mortality controls at facilities with flow less than or equal to 50 mgd.

The first part of this section provides an overall summary of the costs of the regulatory options to regulated facilities and Federal and State governments. This discussion is followed by a review of the method for developing compliance cost estimates. The third part provides an estimate of the total social costs of the regulatory options. The final part reviews the economic impact of the regulatory options.

A. Overview of Costs to Regulated Facilities and Federal and State Governments

In estimating the total cost of the regulatory options, EPA estimated costs for the following components: capital costs and other one-time costs; installation downtime costs; annual operation and maintenance costs; and recordkeeping, monitoring, entrainment-related studies, and reporting costs. All of these costs are included in the economic impact analysis for the final rule. The cost estimates reflect the incremental costs attributed only to this final rule. For example, facilities already having closed-cycle recirculating systems as defined at § 125.92 will meet the impingement mortality and entrainment standards of today's rule and, therefore, will not incur costs to retrofit new technologies. These facilities, including those in New York and California, will still incur permitting costs. EPA has established that existing closed-cycle recirculating systems will comply with the impingement BTA requirements.

For the economic analysis, EPA distinguished between the two industry groups regulated by the standards for existing facilities as follows:

- Electric Power Producers (electric generators)—facilities owned by investor-owned utilities, municipalities, States, Federal authorities, cooperatives, and nonutilities, whose primary business is electric power generation or related electric power services.
- Manufacturing and Other Industries (manufacturers)—facilities in the paper, aluminum, steel, chemicals, petroleum, food and kindred products (primary manufacturing industries), and other industries. In addition to engaging in production activities, some of these facilities also generate electricity for their own use and occasionally produce excess power for sale.

For a more detailed discussion of costs to regulated facilities and costs to Federal, State, and local governments, see Chapter 8 of the TDD and Chapter 3 of the EA.

Electric generators incurring costs include facilities owned by private firms, governments, and electric cooperatives. Manufacturers incurring costs include facilities owned by private firms only. The administrative costs to Federal, State, and local governments include the costs of rule implementation—e.g., permits, monitoring, and working with facilities subject to the final rule to achieve compliance.

In the economic analysis, EPA accounted for these costs on an as-incurred basis. They are reported on a pre-tax or after-tax basis, depending on the specific component of the analysis. These costs also underlie the analysis of the social costs of the regulatory options.

B. Development of Compliance Costs

This section describes the data and methods used to estimate compliance costs of the options considered for today's final rule. Costs were developed for technology controls to address impingement mortality separately from technology controls for entrainment because the requirements of the various rule options considered may lead to different technologies being used by each facility to comply. The options considered may impose different compliance timelines for impingement mortality and entrainment control technologies, although decision making has been synchronized to avoid investments in impingement BTA controls that could later be rendered obsolete by the BTA requirements for entrainment. Different methodologies were used and each is briefly described below. More detailed information on these methodologies and costs of other technologies and regulatory approaches are available in Chapter 8 of the TDD.

1. Combined Facility-Specific and Model-Facility Approach

EPA estimated national level costs for regulated facilities under the final rule and other regulatory options. In general, facility-specific data can be used to determine the requirements that apply to a facility and whether that facility already meets the final rule's requirements. This approach requires facility-specific technical data for the approximately 1,065 facilities that EPA estimates will be subject to the final rule. The change in the number of facilities subject to the final rule compared to the number estimated at proposal is attributable to changes in how EPA accounted for baseline closures. See Appendix H of the EA for more details. An alternative approach is to develop a series of model facilities that exhibit the typical characteristics of the regulated facilities and calculate costs for each model facility; EPA would then determine how many of each model facility would be needed to accurately represent the full universe of regulated facilities.

The approach used in this effort involved calculating compliance technology costs for 338 individual facilities for which EPA had detailed technical data from its questionnaires regarding the intake design and technology. Specifically, these are the facilities that completed the detailed technical questionnaire. Where facilities reported data for separate cooling water intake structures, EPA derived compliance technology costs for each intake, and summed these intake costs to obtain total costs for each facility. EPA used the actual facility data to construct model facilities. Each model facility's costs were then multiplied by a specific weighting factor, derived from a statistical analysis of the industry questionnaire, to obtain industry-wide costs. The weighting factors are similar to the ones derived during the development of the 2004 Phase II and 2006 Phase III rules.

2. Updates to the Survey Data

For the 2004 Phase II rule analysis, EPA developed facility-specific cost estimates for all facilities and published those costs in an appendix (69 FR 41669, July 9, 2004). Since the initial implementation of the 2004 Phase II rule, EPA identified several concerns with using only the facility-specific costing approach, and the use of those costs in Appendix A. Since 2004 EPA has collected data from industry and other groups as described in Section III of the proposed rule (76 FR 22183, April 20, 2011). These data generally reflect changes to actual intake flow, design intake flow, intake velocity, technology in place, and operational status. EPA developed a new master database including this new data to supplement the data from the detailed technical questionnaire. Although it has been more than 10 years since the detailed technical questionnaire was initially collected, EPA has undertaken more than 50 site visits and reviewed available literature. In addition, EPA compared its data with that collected by Edison Electric Institute, Electric Power Research Institute, and the Energy Information Administration. On the basis of that review, EPA concluded that the master database is representative and reasonably reflects costs for all facilities.[102] The following section describes how EPA used this new database to estimate compliance costs.

3. Tools for Developing Compliance Costs

During development of the 2004 Phase II rule, EPA began developing a spreadsheet-based tool that would provide facilities and permit authorities with a simple and transparent method for calculating facility-specific

[102] EPA notes that, while it has not collected updated technical information for every facility, it has updated financial data, as discussed later in this section.

compliance costs. EPA refined the tool in developing the Phase III regulations. EPA has since made further refinements to the cost tool, which was used to calculate the compliance costs for impingement mortality for today's final rule. The cost tool employs a decision tree (for a graphical presentation of the decision tree, see Chapter 8 of the TDD) to determine a compliance response for each model facility. The decision tree assigns a technology costing ''module'' for the retrofit to a given technology. Impingement cost estimates are derived through a series of computations that apply facility-specific data (such as DIF, width of intake screens, and such) to the selected technology module. Cost tool outputs include capital costs, incremental operation and maintenance costs, and installation downtime (in weeks).

To calculate the compliance costs of retrofitting to closed-cycle cooling for controlling entrainment, EPA used a second tool based on a cost-estimating spreadsheet using a modified version of a similar tool developed by the Electric Power Research Institute (EPRI). EPRI's first draft methodology presented three levels of capital cost according to the relative difficulty of the retrofit project (easy, average, and difficult). For electric generators, EPA used costs for the average level of difficulty because it was developed across a broad spectrum of facilities and is the most appropriate for estimating national level costs rather than lower or upper bounds. For manufacturers, EPA used the difficult level of retrofit costs. This reflects the more complex water systems and technical challenges to retrofitting closed-cycle cooling at multiple locations within a manufacturing facility. In site visits, EPA found the largest manufacturing facilities had multiple intakes, distributed the water to multiple production processes, have already significantly increased water reuse as a result of water audits, and generally operate a complicated water distribution network at the entire facility, and would therefore require multiple retrofits to convert the facility to be commensurate with closed-cycle recirculating system.[103] Accordingly, EPA determined that the difficult level of retrofit costs is more representative for purposes of estimating national level costs. EPA's tool includes additional modifications to EPRI's methodology, such as increased compliance costs for approximately 25 percent of facilities to reflect the additional expense of noise control or plume[104] abatement, and using only the cooling water flow rate for non-contact cooling water flow[105] for purposes of estimating costs for closed-cycle cooling. EPA has included the spreadsheet tools in the docket for today's final rule to assist both facilities and permit authorities in estimating compliance costs (see DCNs 12–6650 and 12–6651 for the cost tool, as well as and DCN 10–6930 for EPRI's retrofit analysis).

4. Which technologies form the basis for compliance cost estimates?

EPA identified two broad classes of control technologies that may be used singularly or in combination to comply with the final rule. These classes of control technologies are (1) technologies that address impingement mortality, and (2) technologies that address entrainment. For further details, see Section VI.

For the impingement mortality requirements, EPA analyzed data from a wide variety of technologies and facilities, and concluded that modified (Ristroph or equivalent) 3⁄8″ mesh traveling screens with fish-friendly fish handling and returns are the most appropriate basis for determining compliance costs.[106] As discussed in Section VI of this preamble, a facility may also comply with impingement mortality requirements by meeting a low velocity compliance alternative, operating a closed-cycle recirculating system as defined at § 125.92(c), or employing an existing offshore velocity cap as defined at § 125.92(v). On the basis of facility-specific data, EPA made a preliminary assessment of which model facilities would not currently meet impingement mortality requirements through any of these pre-approved technologies, and assigned technology costs on the basis of modified traveling screens with a fish handling and return system if the existing intake used traveling screens. If the intake does not currently use traveling screens, EPA assigned costs for installing technologies that would comply with the low velocity compliance alternative (larger intakes, wedgewire screens, or variable speed pumps) based on site-specific conditions. These assigned technologies will meet the BTA standard (see § 125.94(b)). Although EPA no longer requires installation of barrier nets or equivalent technologies to protect shellfish in all tidal waters, EPA included the cost of barrier net technology at approximately 10 percent of the intakes as a cost component for the ''systems'' approach to compliance with the IM standards.

EPA also analyzed the costs of those options associated with entrainment requirements based on wet cooling systems. EPA also evaluated other technologies for reducing entrainment, such as seasonal operation of cooling towers, partial towers, variable speed pumps, and fine-mesh screens. The costs of the final rule include but are not limited to permit applications; characterization of the source water, intake structures and any technologies in place; studies of impingement and entrainment; and recordkeeping, monitoring, and reporting. The costs also include costs of technologies for complying with the BTA for IM; the cost of additional technologies that may be required to meet the site-specific BTA for entrainment are not included, nor are costs for additional measures that may be required for protection of listed threatened and endangered species. Section VI further describes the performance of these technologies. A detailed discussion of how the costs were developed is in Chapter 8 of the TDD.

5. How is installation downtime assessed?

Installation downtime is the length of time that a facility might need to shut down for installing a compliance technology. Downtime estimates primarily assume that the facility would need to completely shut down operations for some portion of the installation period to retrofit an intake, such as relocating an intake, connecting wet cooling systems into the facility, or reinforcing condenser housings. EPA estimated downtime as incremental outages, taking into account the periodic outages all facilities incur as part of preventative maintenance or routinely scheduled outages. For example, nuclear facilities have refueling outages approximately every 18 months lasting

[103] A refinery, for example, may have dozens of heat exchange processes throughout the facility, including a mix of wet and dry non-contact cooling equipment.

[104] The EPRI tool includes drift abatement technologies in its cost assumptions, so no additional costs were included for drift eliminators.

[105] As described in the TDD, EPA used only non-contact cooling water flows in determining the proper size for wet cooling towers. Cooling towers are not widely used for contact cooling or process water, so these flows were excluded. For electric generators, the vast majority of flow is non-contact cooling, but manufacturers are more varied in their water usage.

[106] Note that this does not preclude the use of other technologies; EPA simply used the available performance data in deriving the performance requirements. EPA's research has shown that other technologies may also be capable of meeting the final rule requirements; however, these technologies are not available at all facilities.

approximately 40 days.[107] The entrainment control implementation periods under Proposal Option 2, 10 years for fossil fuel facilities and 15 years for nuclear facilities, would provide facilities with an opportunity to schedule the retrofit when other major upgrades are being done, thereby significantly reducing downtime.

For most facilities subject to impingement mortality, EPA assigned no incremental downtime. Facilities that are replacing or rehabilitating existing traveling screens typically do so one intake bay at a time without affecting the overall operations.[108] EPA has also found that facilities that need to scrub screens do so during other routinely scheduled outages. For some compliance technologies, however, such as relocating an intake or expanding an existing intake to lower the intake velocity, several weeks of downtime may be incurred because these are more invasive tasks. See TDD Exhibit 8–4 for EPA's net construction downtime for the various IM compliance technologies.

EPA reviewed historical retrofit data and site visits conducted since 2004 and has largely retained its assumptions for downtime from the Phase II and Phase III rules for facilities retrofitting to closed-cycle cooling. On average, EPA assumes the net installation downtime for retrofitting to closed-cycle cooling for non-nuclear electric generators is 4 weeks. This total downtime allows for the tie-in of the closed-cycle system to the existing cooling water system. The refueling outage downtime, the safety-sensitive nature of nuclear facility retrofits, and other data in EPA's record supports 28 weeks as the net construction downtime for nuclear facilities. EPA converted downtime for manufacturing facilities that use cooling water for power and steam generation into the incremental cost for purchasing electricity during the outage. For individual process units other than power generation units at a manufacturing facility, on average the downtime was assumed to be zero. In EPA's extensive experience with manufacturers, EPA's record reflects that manufacturers are generally able to shut down individual intakes for specific process lines, use inventory approaches such as temporary increases of intermediate products, and develop other workarounds without interrupting the production of the entire facility. For further discussion of how EPA accounted for installation downtime in estimating national costs, see below.

[107] Nuclear Energy Institute reported average length of outage from 2003 to 2009.

[108] EPA's data shows that facilities have an average of 4 to 5 bays.

6. How is the energy penalty assessed?

The term *energy penalty* in relation to a conversion to closed-cycle cooling has a number of different interpretations. The first is the extra power required to operate fans at a mechanical draft cooling tower and additional pumping requirements (sometimes referred to as auxiliary energy requirements or parasitic loads). The second is the lost power output because of the reduction in steam turbine efficiency from an increase in cooling water temperature relative to once-through cooling (often referred to as the turbine efficiency penalty or turbine backpressure penalty). EPA is clarifying that it views the former as incremental O&M costs, and the latter is EPA's interpretation of the energy penalty. Energy penalty costs apply only to facilities retrofitting to closed-cycle cooling without replacing the condenser. Facilities installing a new impingement mortality technology will not generally face an energy penalty and will generally see little or no measureable change in auxiliary power consumption. EPA's national-level costs include both these costs. The auxiliary power consumption was included as a separate component in the operation and maintenance costs and was assessed for all facilities. The turbine efficiency penalty was typically expressed as a percentage of power output. EPA estimates the turbine efficiency energy penalty for nuclear and non-nuclear power generation would be 2.5 and 1.5 percent, respectively (see Chapter 8 of the TDD). For most manufacturers generating their own electricity, EPA assumed the same energy penalty for turbine efficiency loss as estimated for non-nuclear power facilities (i.e., 1.5 percent).

7. How did EPA assess facility-level costs for the national and regional economic impacts analysis?

As part of the economic impact analysis, EPA assessed the impact of the final rule's requirements on electric generators in the context of national and regional electricity markets. For this analysis, EPA used the Integrated Planning Model (IPM®), a comprehensive electricity market optimization model that assesses such impacts within the context of regional and national electricity markets. EPA has used IPM to analyze the impacts of various regulatory actions affecting the electric power sector over the last decade, particularly Clean Air Act regulations.

Because IPM requires facility-specific costs for each analyzed facility, yet compliance costs were developed as weighted sums of model facility costs, EPA developed a method to distribute the aggregate costs to facilities that were not themselves model facilities. For these facilities, EPA converted facility-level costs developed for model facilities to a cost per mgd DIF and then averaged these values to derive cost equations using DIF as the independent variable. These cost equations provide average costs that can be applied to any facility by simply scaling to that facility's DIF. For details on the IPM analysis, see the EA, Chapter 6. For details on facility cost development, see the TDD, Chapter 8.

8. How did EPA assess costs for new units?

Power generation and manufacturing units that are a *new unit* as defined at § 125.92(u) must meet an entrainment reduction performance standard based on closed-cycle cooling or an equivalent reduction in entrainment for the cooling water component of the intake flow based on the DIF. This section briefly describes the data and methods used to estimate compliance costs for new units at existing electric generators and manufacturers. Chapter 8 of the TDD has a complete description of the methodology.

a. New Units at Existing Electric Generators

Compliance costs for new units at existing electric generators are estimated using a similar methodology to that used for estimating compliance costs for existing facilities. As described in Chapters 6 and 8 of the TDD, however, there are a number of differences in costs between a closed-cycle cooling retrofit at an existing facility compared to installing closed-cycle cooling at a new unit. In general, these differences result in lower costs for the installation of a closed-cycle recirculating system at a new unit (as compared to a retrofit scenario), due to improved efficiency of the turbine, the elimination of construction downtime, greater ease of integrating the closed-cycle system into the design and construction of the new unit, offsetting costs of certain system and construction components, and greater overall system optimization.

EPA could not determine precisely which facilities will construct new units. Instead, EPA used an approach to estimate what portion of the new capacity (i.e., additional megawatts capacity to be constructed each year) would be subject to the final rule. Using national projections of increased generating capacity,[109] EPA categorized the new capacity into three groups for 316(b) compliance purposes: (1) Subject to the Phase I rule,[110] (2) subject to today's final rule, but projected to install a cooling system that complies with the rule regardless of the rule requirements,[111] and (3) subject to today's rule and projected to incur compliance costs. Exhibit IX–1 presents the estimated total new capacity and the estimated capacity for new stand-alone units.

EXHIBIT IX–1

Fuel type	Total including Phase I	Existing facility new units only
	New Capacity (MW)	Stand-Alone (MW)
Fossil Fuel	295	80
Combined Cycle	3,264	147
Total	3,559	227

Costs for closed-cycle cooling are assigned to a portion of new stand-alone units, as shown the generating capacities in Exhibit IX–3.

EXHIBIT IX–3

Fuel type	Annual only	24-year total only
	Stand-Alone MW	Stand-Alone MW
Fossil Fuel	8	191
Combined Cycle	15	353
Total	23	544

EPA then estimated the total costs for the third group (i.e., those units that would incur compliance costs) to comply with requirements for new units. EPA used certain assumptions regarding cooling system design to modify cost equations used for estimating closed-cycle retrofit costs at existing units and then applied the cost equations to the portion of projected new unit generating capacities that would be subject to the new unit provisions of today's rule. These costs include capital [112] and O&M costs, as well as a reduction in net generating capacity due to auxiliary power consumption to operate the closed-cycle recirculating system. Due to the complex nature of constructing a new unit, there is no increase in the length of the construction project as a result of employing a closed-cycle system; similarly, there is no downtime, as the unit has not yet begun operating. See Chapter 8 of the TDD for more information.

b. New Units at Existing Manufacturers

On the basis of site visits to manufacturing facilities, EPA has observed that manufacturers are increasingly taking advantage of water conservation and reuse measures as a means of cost-cutting. EPA also notes that manufacturers are subject to a wide variety of ELGs and that, in the course of complying with requirements for those ELGs, a facility may also reduce its intake flow. (See Chapter 4 of the TDD.) A new unit provides the opportunity to employ such measures to the fullest extent in designing the new unit. The availability of water conservation and reuse opportunities, coupled with operational flexibility at facilities with multiple industrial processes, leads EPA to conclude that facilities installing new units at existing manufacturers will comply with the new unit provisions through achieving the 90 percent reduction required at § 125.94(e)(2). Thus, EPA concluded that the new unit provisions would result in no additional compliance costs for achieving flow commensurate with closed-cycle cooling at new units.[113]

To the extent that manufacturers are not able to incorporate water reuse measures as a means of complying with the new unit provision, EPA's estimate of new unit costs for manufacturers may be an underestimate. Manufacturers generally withdraw less water than electric generators (including manufacturers who generate their own electricity). Thus EPA has concluded that any underestimation would be insignificant.

C. Social Costs

EPA assessed the costs to society resulting from the final rule and other options considered in development of this rule. The findings presented in this section assume that facilities with impoundments will qualify as having closed-cycle recirculating systems in the baseline.[114] As a result, EPA assigned no compliance technology costs to these facilities; however, these facilities remain subject to today's rule and are assigned administrative costs. To the extent that some of these facilities do not qualify as having closed-cycle recirculating systems in the baseline, the costs reported in this section may be underestimates. The social cost of regulatory actions includes costs to electric generators and manufacturers to comply with the final rule, and costs to States and the Federal government to administer the rule. These costs are the opportunity costs to society of employing scarce resources to prevent the environmental damage that would occur without today's rule. EPA estimated total social costs for existing and new units at existing facilities.

In estimating social costs, EPA assumed that the final rule and other options considered in development of this rule will not affect the aggregate quantity of electricity or other affected goods and services sold to consumers. Thus, the social cost of regulatory requirements includes no loss in consumer and producer surplus from reduced sales of electricity or other goods and services produced by regulated facilities. The Agency calculated the social cost of the final

[109] Capacity increases include considerations for fuel type. See Chapter 8 of the TDD for details.

[110] New capacity that is part of a new facility (as defined by the Phase I rule) is subject to separate requirements not addressed by today's rule. Today's requirements for new units require flow reduction commensurate with a closed-cycle recirculating cooling system.

[111] Data in the record show a marked increase in the use of closed-cycle cooling in facilities constructed in recent years and for those projected to be constructed in the near future. These data indicate that in the 1990s (prior to the Phase I rule), 83 percent of new cooling systems installed were closed-cycle cooling systems and that the current trend was approximately 97 percent. Based on these data EPA assumed that 75 percent to 90 percent of new units will be designed with a closed-cycle recirculating cooling system regardless of the requirements of today's rule. See DCN 12–6672. As a result, this category of new capacity was not assigned any compliance costs.

[112] The record indicates that the total estimated capital cost for installing a closed-cycle recirculating system at a new unit to comply with today's rule ranges from a negative value (as compared to the cost for installing a once-through system) to a positive value that could approach the cost of an existing facility retrofit. Said differently, if one assumes that the new unit would have constructed a new intake structure, EPA's record shows that the capital costs for the new unit once-through system would be greater than if the new unit installs a closed-cycle recirculating system. (See DCN 10–6650.) Alternatively, if the new unit did not require modification of the existing cooling system infrastructure, then the capital costs for installing a closed-cycle recirculating system would be similar to an existing facility retrofit minus some tie-in costs since the condenser is being replaced. While EPA envisions that the actual costs will vary (i.e., some will be in the negative portion of the range and others will be in the positive), EPA is also unable to project what cooling water intake arrangements a new unit will use. Consequently, for all new units, EPA selected a capital cost equal to the midpoint between the tower only and the easy retrofit costs. As a result, EPA assumed that the capital costs for these units was $154 per gpm in 2009 dollars which converts to $30,800 to $60,060 per MW capacity depending on fuel type. For a more detailed discussion, see TDD Chapter 8.

[113] EPA also notes that some manufacturers may also be able to increase reuse to a degree where the facility no longer meets the applicability thresholds of today's rule.

[114] In other words, EPA assumed facilities indicating use of an impoundment in response to their technical survey have lawfully created such impoundments for the purposes of cooling water.

rule and the other options considered using two discount rates: 3 percent and 7 percent.

For existing facilities, EPA assumes that all facilities subject to the final rule will begin bearing costs associated with today's rule beginning as soon as 2014, and likely complete investments associated with today's rule by 2030, depending on the technology-installation schedules for the final rule and other regulatory options considered.[115] EPA performed the social cost analysis over a 51-year period to reflect (1) the last year in which individual facilities are expected to achieve compliance (2030) under the final rule or any of the options considered, (2) the life of the longest-lived compliance technology installed at any facility (30 years), and (3) a period of five years after the last year of compliance technology operation during which benefits continue to accrue. Under this framework, the last year for which EPA has calculated projected costs is 2059, with benefits continuing beyond 2059, though on a diminishing basis, through 2064.[116]

To estimate social costs for existing facilities, EPA developed a year-explicit schedule of compliance outlays over the 46-year period from 2014 to 2059 according to cost-incurrence assumptions (for details on cost-incurrence assumptions, see EA, Chapter 3). EPA then adjusted these costs for predicted real change (i.e., adjusted for inflation) to the year of their incurrence and discounted all costs to the beginning of 2013, the promulgation year used for the analysis. Because the analysis period extends beyond the useful life of some compliance equipment, the social cost analysis accounts for re-installation of impingement mortality compliance technologies after the end of their initial useful life periods. However, for the regulatory option that requires a specific entrainment control technology (e.g., wet cooling systems)—Proposal Option 2—EPA does not expect regulated facilities to completely rebuild these systems (components such as piping and the concrete basin can be reused). EPA accounted for other technology replacement costs (such as pumps and fill material) as part of ongoing operations and maintenance expenses.

For new units at existing electric generators, EPA calculated an average annual amount of new capacity to be constructed during the 46-year social cost analysis period, beginning in 2014. While EPA does not expect the annual construction of new units to be constant, predicting the year-to-year fluctuations would be resource intensive. On average, EPA assumes that its estimate of new unit costs is reasonable. EPA accounted for compliance costs for these units on an as-incurred basis, as done for existing facilities. Similar to compliance costs for facilities subject to the final rule, EPA analyzed costs incurred by State and Federal governments for administering the regulation on a year-explicit basis over the 46-year social cost analysis period.

Exhibit IX–4 presents social costs for existing units at existing facilities under the final rule and other options considered, calculated using 3 percent and 7 percent discount rates. At the 3 percent discount rate, EPA estimates total annualized social costs of $272 million for the existing unit provision of today's rule, $252 million for Proposal Option 4, and $3,643 million for Proposal Option 2. At the 7 percent discount rate, these costs are $295 million for today's rule, $272 million for Proposal Option 4, and $3,583 million for Proposal Option 2.[117] See the EA (Chapter 7) for an explanation of why the annualized costs at the 3 percent discount rate are lower than the annualized costs at the 7 percent discount rate for the final rule and Proposal Option 4, while the inverse is the case for Proposal Option 2 (annualized costs at the 3 percent discount rate are higher than at the 7 percent discount rate). The largest component of social cost is the cost of regulatory compliance incurred by regulated facilities (as opposed to administrative costs estimated for States and the Federal government). These costs include (1) one-time technology and other initial costs of complying with the rule, (2) one-time costs of installation downtime, (3) annual fixed and variable operating and maintenance costs, including auxiliary energy requirement, (4) value of energy penalty from operation of compliance technology, and (5) permitting costs (initial and follow-up start-up costs, initial permit costs, annually recurring costs associated with monitoring, and non-annually recurring permitting costs).

Compliance costs estimated for electric generators account for the largest share of total compliance-related social cost and direct compliance cost under all three options. On a per-facility basis and at the 3 percent discount rate, the annualized pre-tax compliance costs for the electric generators segment under today's final rule are $0.4 million, $0.4 million under Proposal Option 4, and $6 million under Proposal Option 2.[118] For manufacturers, the average cost per regulated facility at the 3 percent discount rate is $0.1 million under the final rule and Proposal Option 4, and $0.4 million under Proposal Option 2.[119] EPA's analysis found a similar profile of per facility costs using the 7 percent discount rate (see EA Chapter 7 for additional detail). EPA's estimate of Federal and State government costs for administering this rule is small in relation to the estimated direct cost of regulatory compliance. EPA estimates $1 million in annual administrative costs to States and Federal government for the final rule, using both the 3 and 7 percent discount rates. These cost values are the same for Proposal Option 4. EPA estimates $0.7 million in annual administrative costs to States and the

[115] EPA conducted the cost and economic impact analyses on a calendar-year basis. For these analyses, EPA used calendar year 2013 as the promulgation year of today's rule and 2014 as the first post-promulgation analysis year. This slight difference from the actual promulgation year of 2014 results from the fact that EPA completed its cost and economic impact analyses for the final rule and alternative options before EPA decided to delay promulgation from 2013 to 2014. Because the rule is being promulgated during the first half of 2014, EPA concluded that it would be reasonable to continue using 2013 as the assumed promulgation year for the regulatory analysis. EPA expects the differences in the estimated costs and benefits of the rule due to this slight imprecision to be minimal.

[116] For this analysis, EPA assumed that the last year of technology installation for all regulated facilities under any of the regulatory options—i.e., 2030—is also the first year of steady-state compliance with regulatory requirements.

[117] Because EPA was unable to identify those facilities for which entrainment control technology would be established as BTA standards on a site-specific basis, the Agency did not analyze technology costs associated with these site-specific requirements. Consequently, the cost and economic analyses conducted in support of today's rule assume that under the existing unit provision of the final rule and Proposal Option 4, Electric Generators and Manufacturers install IM technology only. These analyses also assume that under Proposal Option 2, Electric Generators with DIF exceeding 125 mgd install only cooling towers and all other Electric Generators install only IM technologies. Under Proposal Option 2, a small number of Manufacturers are assigned both IM and entrainment control technologies because of engineering issues associated with maintaining separation of contact and non-contact cooling water in some manufacturing operations. Although EPA did not estimate technology costs for facilities for which entrainment technology is established as BTA on a site-specific basis, EPA did include the costs for data collection and studies that facilities will need to perform in order to provide information to Directors to make these site-specific determinations. EPA included these costs in the administrative costs that are estimated for the final rule and other options considered.

[118] Calculated by dividing direct compliance costs for each type of facility by the total of 544 electric generators subject to today's rule on the basis of facility count-based weights (see EA Appendix H).

[119] Calculated using the total of 521 manufacturers subject to today's rule on the basis of technical weights (see EA Appendix H).

Federal government for Proposal Option 2, regardless of the discount rate used.

EXHIBIT IX–4—TOTAL ANNUALIZED SOCIAL COSTS—EXISTING UNITS AT EXISTING FACILITIES

[in millions, 2011 dollars] [a]

	Proposal option 4	Final rule	Proposal option 2
Using 3 percent discount rate			
Direct Compliance Costs:			
Electric Generators	$202.9	$203.7	$3,413.3
Manufacturers	47.8	67.7	229.2
Total Direct Compliance Cost	250.7	271.4	3,642.5
State and Federal Administrative Costs	1.0	1.0	0.7
Total Social Costs	251.8	272.4	3,643.2
Using 7 percent discount rate			
Direct Compliance Cost:			
Electric Generators	219.2	220.0	3,339.3
Manufacturers	51.9	74.2	243.0
Total Direct Compliance Cost	271.1	294.3	3,582.3
State and Federal Administrative Costs	1.0	1.0	0.7
Total Social Costs	272.1	295.3	3,583.0

[a] Cost estimates exclude costs associated with baseline closure facilities.

EPA also estimated the cost for installing closed-cycle recirculating systems at new units at existing electric generators, to reflect the costs of today's rule. As shown in Exhibit IX–5, EPA estimated that the new unit provision of the final rule will result in an annualized cost of $2.5 million and $2.0 million using 3 percent and 7 percent discount rates, respectively, including compliance costs to facilities and administrative costs to States and Federal government.

The Agency estimated that at a 3 percent discount rate, the total social cost of the final rule, including the existing and new unit provisions, will be $275 million. At a 7 percent discount rate, this cost is $297 million.

EXHIBIT IX–5—ANNUALIZED TOTAL SOCIAL COST OF THE FINAL RULE—EXISTING AND NEW UNITS AT EXISTING FACILITIES

[In millions, 2011 dollars] [a b]

	3% Discount rate	7% Discount rate
New Units	$2.5	$2.0
Existing Units	272.4	295.3
Existing and New Units	274.9	297.3

[a] Cost estimates exclude costs associated with baseline closure facilities.
[b] Values may not add due to rounding.

D. Economic Impacts

EPA used several analytic approaches to assess the economic impact of today's rule and the other options considered, on electric generators and manufacturers. EPA conducted separate analyses for electric generators and manufacturers using different methodologies for each regulated facilities segment. The following sections summarize the methodologies EPA used to conduct the economic impact analyses and the findings of these analyses. EPA conducted the economic impact analyses discussed in this section for existing facilities; the Agency used compliance cost estimates from the EPA engineering analysis (see TDD Section X.B).

1. Electric Generators

For the electric generators segment, EPA assessed the economic impact of the existing unit provision of the final rule and other options it considered in three ways: (1) The financial burden associated with a particular regulatory option on facilities and entities that own them, (2) how potential changes in the price of electricity would affect electricity consumers, in general, and residential households, in particular, and (3) broader economic impacts on the electricity market, taking into account the interconnectedness of regional and national electricity markets. In preparing the first two sets of analyses, EPA developed and used sample weights to extrapolate impacts assessed initially at the level of sample of facilities, to the full population of facilities subject to the final rule. For information on how EPA developed and used sample weights, see the EA, Appendix H.

In addition, EPA assessed the impact of the new unit provision of the final rule on decisions of existing facilities to construct stand-alone new units that would be subject to the new unit provision. EPA made this assessment in two ways: (1) On the basis of comparison, on a per MW basis, of compliance costs for new units to the overall cost of building and operating generating units and (2) as is the case with the existing unit provision, in the context of regional and national electricity markets, taking into account their interconnectedness.

a. Cost-to-Revenue Analysis for Regulated Facilities and Their Parent Entities—Existing Unit Provision of the Final Rule

EPA assessed the cost to regulated facilities and their parent entities on the basis of a cost-to-revenue analysis. For each analysis level (facility and parent entity), the Agency assumed, for analytic convenience and as a worst-case scenario, that none of the compliance costs would be passed on to consumers through electricity rate increases and, instead, would be absorbed by regulated facilities and their parent entities.[120] EPA developed

[120] As discussed in EA Chapter 2A: Industry Profiles, the majority of regulated electric generators operate in States with regulated electricity markets. EPA estimates that facilities located in these States may be able to recover compliance cost-based increases in their production costs through increased electricity prices. This depends on the business operation model of the facility owner(s), the ownership and operating structure of the facility itself, and the role of market mechanisms used to

Continued

this analysis for 544 electric generators.[121]

i. Cost-to-Revenue Analysis for Regulated Facilities

To provide insight into the potential significance of the compliance costs to regulated facilities, EPA calculated the ratio of annualized after-tax compliance costs to baseline annual facility-level revenues. In the cost-to-revenue comparisons, EPA used cost-to-revenue thresholds of 1 and 3 percent to categorize facilities according the potential economic impact of the rule. EPA concludes that facilities incurring costs below 1 percent of revenue will not face significant economic impacts, while facilities with costs of at least 1 percent but less than 3 percent of revenue have a chance of facing economic impacts, and facilities incurring costs of at least 3 percent of revenue have a higher probability of significant economic impacts. For a more detailed discussion of the methodology EPA used for the facility-level cost-to-revenue analysis, see EA Chapter 4.

Exhibit IX–6 presents a summary of the facility-level cost-to-revenue analysis results for the final rule and other options considered. EPA estimates that overall, under the final rule, 86 percent of regulated facilities will incur compliance costs of less than 1 percent of revenue. Under Proposal Option 4, 87 percent of regulated facilities would also incur costs of less than 1 percent of revenue. EPA estimates that Proposal Option 2 would result in 42 percent of facilities incurring costs exceeding 1 percent of revenue, and 43 percent incurring costs exceeding 3 percent of revenue.

EXHIBIT IX–6—FACILITY-LEVEL COST-TO-REVENUE ANALYSIS RESULTS FOR THE FINAL RULE AND OPTIONS CONSIDERED [a]

Option	Number of facilities with cost-to-revenue ratio					
	< 1%		≥ 1% and < 3%		≥ 3%	
	#	%	#	%	#	%
Proposal Option 4	475	87.4	35	6.5	31	5.7
Final Rule	470	86.5	40	7.4	31	5.7
Proposal Option 2	228	41.9	79	14.5	235	43.2

[a] Facility counts exclude baseline closures.
[b] EIA reports no revenue for 1 facility (2 on a weighted basis). Therefore, EPA conducted this analysis for 339 facilities (542 on a weighted basis). For more information on facility sample weights see EA Appendix H.

ii. Cost-to-Revenue Analysis for Regulated Parent Entities

EPA also assessed the economic impact using the cost-to-revenue metric at the level of the parent entity. This analysis, which focuses on domestic parent entities with the largest ownership share in the facility, provides insight on the impact of compliance requirements on those entities that own more than one regulated facility. The analysis helps to answer the question of whether owning multiple facilities that are required to comply with today's rule causes financial stress at the entity level. For each identified parent entity, EPA aggregated facility-level, annualized, after-tax compliance costs to the level of the parent entity and compared these entity-level costs to entity-level revenue.

Similarly to the facility-level analysis, EPA used cost-to-revenue thresholds of 1 and 3 percent to categorize facilities according the potential economic impact of the rule. EPA used two weighting approaches for this analysis: (1) Facility-level weights, but without entity-level weights and (2) entity-level weights, but without facility-level weights. These approaches, which are described in Appendix H of the EA, provide a range of estimates for the number of entities incurring compliance costs and the costs incurred by any entity that owns a regulated facility. (For a more detailed discussion of the methodology used for the entity-level cost-to-revenue analysis, see EA Chapter 4).

Exhibit IX–7 presents results for the entity-level analysis for the two weighting approaches. EPA estimates that between 123 and 159 entities own regulated facilities. Further, the Agency estimates that between 91 and 94 percent of parent entities will incur annualized costs of less than 1 percent of revenues under the final rule. This finding also holds under the two other options EPA considered, with between 91 and 94 percent of entities incurring costs of less than 1 percent of revenue under Proposal Option 4 and between 70 and 78 percent under Proposal Option 2.

EXHIBIT IX–7—ENTITY-LEVEL COST-TO-REVENUE ANALYSIS RESULTS [b]

Parent entity type	Total number of entities	Number of entities with cost-to-revenue ratio of							
		< 1%		≥ 1% and < 3%		≥ 3%		Unknown [a]	
		#	%	#	%	#	%	#	%
Using Facility-Level Weights:									
Proposal Option 4	123	112	91.1	3	2.4	0	0.0	8	6.5
Final Rule	123	112	91.1	3	2.4	0	0.0	8	6.5
Proposal Option 2	123	86	69.9	17	13.8	12	9.8	8	6.5
Using Entity-Level Weights:									
Proposal Option 4	159	150	94.2	0	0.0	0	0.0	9	5.8

sell electricity. In contrast, in States where electric power generation has been deregulated, cost recovery is less certain. While facilities operating within deregulated electricity markets may be able to recover some of their additional production costs through increased revenue, EPA cannot determine the extent of cost recovery ability for each facility.

[121] EPA calculated this number as a weighted estimate using facility count-based weights. This number excludes facilities assumed either to have already retired their steam operations or expected to do so in the future.

EXHIBIT IX–7—ENTITY-LEVEL COST-TO-REVENUE ANALYSIS RESULTS [b]—Continued

Parent entity type	Total number of entities	Number of entities with cost-to-revenue ratio of							
		< 1%		≥ 1% and < 3%		≥ 3%		Unknown [a]	
		#	%	#	%	#	%	#	%
Final Rule	159	150	94.2	0	0.0	0	0.0	9	5.8
Proposal Option 2	159	124	78.1	18	11.6	7	4.4	9	5.8

[a] EPA was unable to determine revenues for 8 parent entities (9 weighted).
[b] This analysis assumes no cost pass-through to electricity consumers.

b. Potential Electricity Price Effects—Existing Unit Provision of the Final Rule

As an additional measure of economic impact, EPA conducted two assessments of the potential price effects on electricity of today's rule: (1) The annual increase in electricity costs per MWh (megawatt hour) of total electricity sales and (2) the potential annual increase in household electricity costs. For analytic convenience and as a worst-case scenario, these assessments assume that all compliance costs will be passed through on a pre-tax basis to consumers as increased electricity prices. This full cost pass-through assumption represents a ''worst-case'' impact scenario from the perspective of electricity consumers. Facilities that are merchant providers can pass along costs only to the degree that they are competitive with other generators in the dispatch process.[122] This assumption is the opposite of EPA's assumption in the facility- and entity-level analyses discussed above—that facilities will pass none of the compliance costs through to consumers in electricity rate increases. If facilities are able to pass through all costs, the impacts in the previous subsection would not occur. The two conditions (no cost pass-through and full cost pass-through) could not occur at the same time. Thus, the results of the electricity price-effects analyses discussed in this section, and of the facility- and entity-level analyses discussed in Section IX.D.a.1, should not be combined. EPA conducted this analysis for 544 electric generators.

i. Compliance Cost per Unit of Electricity Sales

EPA assessed the potential increase in electricity rates by NERC region based on the annual cost of the regulatory options per unit of electricity sold. The Agency used two data inputs: (1) Total pre-tax compliance cost by NERC region, and (2) estimated total electricity sales in the year 2020, to gauge the full effects of the rule. To calculate the total estimated annual cost in each NERC region, the Agency summed sample-weighted, pre-tax annualized compliance costs over regulated facilities by region. EPA then calculated the approximate average price impact per unit of electricity consumption by dividing total compliance costs by the reported total MWh of sales in each NERC region. (Details of this analysis are presented in the EA, Chapter 4.)

As reported in Exhibit IX–8, under the existing unit provision of the final rule, annualized compliance costs (in cents per kWh sales) range from nearly $0.00 in the WECC region to $0.040 in the HICC region. EPA reached the same findings for Proposal Option 4. Under Proposal Option 2, costs range from $0.00 in the WECC region to $0.351 in the HICC region. On average, across the United States, the final rule and Proposal Option 4 result in a cost of $0.009 per kWh, while Proposal Option 2 results in a higher cost of $0.155 per kWh.

EXHIBIT IX–8—COMPLIANCE COST PER UNIT OF ELECTRICITY SALES IN 2020 BY REGULATORY OPTION AND NERC REGION

[2011 ¢/KWh sales] [a b]

NERC region [c d]	Proposal option 4	Final rule	Proposal option 2
ASCC	0.000	0.000	0.000
FRCC	0.014	0.014	0.171
HICC	0.040	0.040	0.351
MRO	0.010	0.010	0.174
NPCC	0.008	0.008	0.126
RFC	0.011	0.011	0.200
SERC	0.013	0.013	0.219
SPP	0.009	0.009	0.078
TRE	0.008	0.008	0.206
WECC	0.000	0.000	0.000
United States	0.009	0.009	0.155

[a] This analysis assumes full pass-through of all compliance costs to electricity consumers.
[b] Cost values exclude baseline closures.
[c] ASCC—Alaska Systems Coordinating Council; FRCC—Florida Reliability Coordinating Council; HICC—Hawaii Coordinating Council; MRO—Midwest Reliability Organization; NPCC—Northeast Power Coordinating Council; RFC—ReliabilityFirst Corporation; SERC—Southeastern Electric Reliability Council; SPP—Southwest Power Pool; TRE—Texas Reliability Entity, and WECC—Western Energy Coordinating Council.
[d] No explicitly analyzed facilities are in the ASCC region. For more information on explicitly and implicitly analyzed regulated facilities, see EA Appendix H.

[122] As discussed earlier in Section X.D.b.1, even though individual regulated facilities may not be able to recover all of their compliance costs through increased revenues, the market-level effect may still be that consumers will see higher overall electricity prices because of changes in the cost structure of electricity supply and resulting changes in market-clearing prices in deregulated electricity markets.

ii. Cost to Households

As an additional measure of the potential electricity price effects associated with the final rule, EPA estimated the potential annual increase in electricity costs per household and by NERC region. EPA used total annualized pre-tax compliance cost per MWh of sales, as estimated for the electricity rate impact analysis discussed above and the quantity of residential electricity sales per household as reported in the 2011 EIA database. To calculate the potential annual cost impact per household, EPA multiplied the average cost per kWh by the average kWh per household estimated for each NERC region. (Chapter 4 of the EA presents details of this analysis.)

As presented in Exhibit IX–9, under the existing unit provision of the final rule, the average annual cost per residential household varies across NERC regions, ranging from $0.01 in WECC to $2.82 in HICC. EPA reached the same findings for Proposal Option 4. Under Proposal Option 2, the average annual cost per residential household also varies across NERC regions, ranging from $0.01 in WECC to $31.72 in SERC. EPA estimated that on average, for a typical U.S. household, the final rule will result in an annual cost of $1.03 in higher electricity rates per household. EPA estimates that this cost would be $1.03 per household under Proposal Option 4 and $17.23 per household under Proposal Option 2.

EXHIBIT IX–9—AVERAGE ANNUAL COST BURDEN PER RESIDENTIAL HOUSEHOLD IN 2020 FOR THE FINAL RULE AND OPTIONS CONSIDERED, AND BY NERC REGION

[2011 dollars] [a] [b]

NERC region [c] [d]	Proposal option 4	Final rule	Proposal option 2
ASCC	$0.00	$0.00	$0.00
FRCC	1.91	1.91	23.15
HICC	2.82	2.82	24.61
MRO	0.99	1.02	18.10
NPCC	0.61	0.62	9.52
RFC	1.10	1.10	20.64
SERC	1.96	1.96	31.72
SPP	1.30	1.30	10.71
TRE	1.15	1.15	30.59
WECC	0.01	0.01	0.01
United States	1.03	1.03	17.23

[a] The rate impact analysis assumes full pass-through of all compliance costs to electricity consumers.
[b] Cost estimates exclude baseline closures.
[c] ASCC—Alaska Systems Coordinating Council; FRCC—Florida Reliability Coordinating Council; HICC—Hawaii Coordinating Council; MRO—Midwest Reliability Organization; NPCC—Northeast Power Coordinating Council; RFC—ReliabilityFirst Corporation; SERC—Southeastern Electric Reliability Council; SPP—Southwest Power Pool; TRE—Texas Reliability Entity, and WECC—Western Energy Coordinating Council.
[d] No explicitly analyzed facilities are in the ASCC region. For more information on explicitly and implicitly analyzed regulated facilities, see EA Appendix H.

As noted above, this analysis assumes that facilities will pass through to consumers all compliance costs through increased electricity rates. However, facilities and owner entities might not be able to recover all these costs through rate increases, thereby reducing the impact of today's rule on electricity consumers. At the same time, EPA recognizes that electric generators that operate as regulated public utilities will generally recover environmental compliance costs through rate increases to consumers.

c. Barrier-To-Development Analysis—New Unit Provision of the Final Rule

EPA assessed the impact of the new unit provision of the final rule on decisions of existing facilities to construct stand-alone new units that would be subject to the new unit provision. As discussed earlier in this preamble, under this provision, electric power generating units that meet the definition of a new unit will be required to achieve intake flow commensurate with closed-cycle cooling. The question of potential impact of this provision on the construction of new stand-alone units is important because new stand-alone units will generally operate with higher energy efficiency and lower environmental impact than older electric generating capacity, which the new units would tend to displace as a source of electric power generation. As such, EPA sought to ensure that the new unit provision would not impede construction of stand-alone new units.

For this analysis, EPA compared the compliance costs for new units to the overall cost of building and operating generating units, on a per MW basis. The purpose of this analysis is to determine whether the required addition of a closed-cycle recirculating system (CCRS) as part of a new unit would substantially increase the cost for the new stand-alone unit, and adversely affect the decision to construct the new stand-alone unit. This analysis showed that given the low cost of CCRS in relation to the cost of new capacity, the CCRS requirement will not pose a barrier to development of new stand-alone units.

EPA also assessed the costs associated with the new unit provision of the final rule as part of its electricity market analysis, as discussed in the following section (Section IX.D). This analysis tests the impact of the new unit requirements on electricity markets accounting for the expected number and timing of new unit installations, and provides additional insight on whether the costs of complying with the new unit provision of the final rule would affect future capacity additions. This analysis found no material effect of the final rule's new unit provision on the number and type of new units that would be constructed. This finding also supports EPA's conclusion that the new unit provision will not be a barrier to development of new capacity.

d. Impacts in the Context of Electricity Markets—Existing and New Unit Provisions of the Final Rule

In the analyses for the previous 316(b) regulations, including the proposed rule, EPA used the Integrated Planning Model (IPM®),[123] a comprehensive electricity market optimization model, to assess the economic impact of regulatory options within the context of

[123] Developed by ICF, Inc.

regional and national electricity markets. To assess facility and market-level effects of the final rule, EPA used an updated version of this same analytic system, the Integrated Planning Model Version 4.10 MATS (IPM V4.10_MATS) platform.

Use of a comprehensive, market analysis system is important in assessing the potential impact of the final rule because of the interdependence of electricity generating units in supplying power to the electric transmission grid. Increases in electricity production costs and potential reductions in electricity output at regulated facilities—due to the temporary shutdown of existing electric generating units during technology installation—can have a range of broader market impacts that extend beyond the effect on regulated facilities and their direct customers. In addition, the impact of compliance requirements on regulated facilities may be seen differently when the analysis considers the impact on those facilities in the context of the broader electricity market instead of looking at the impact on a stand-alone, single-facility basis.

The IPM V4.10_MATS platform provides outputs for the NERC regions that lie within the continental United States. This IPM platform does not analyze electric power operations in Alaska and Hawaii because these operations are not connected to the continental U.S. power grid. The IPM V4.10_MATS platform is based on an inventory of U.S. utility- and non-utility-owned boilers and generators that provide power to the integrated electric transmission grid, as recorded in the EIA 860 (2006) and EIA 767 (2005) databases.[124] IPM does not include electric power facilities that do not provide power to the U.S. power grid (e.g., some generating units at industrial facilities). The IPM V4.10_MATS universe consists of 14,920 generating units at 4,910 existing electric power facilities, including 520 of the 544 regulated electric power facilities subject to the final rule.[125]

This IPM V4.10_MATS platform embeds a baseline energy demand forecast from the Department of Energy's Annual Energy Outlook 2010 (AEO2010), with adjustments by EPA to account for the effect of certain voluntary energy efficiency programs. This platform also incorporates in its analytic baseline the expected compliance response to existing regulatory requirements for the following promulgated air regulations affecting the power sector: the final Mercury and Air Toxics Standards (MATS) rule; the final Cross-State Air Pollution Rule (CSAPR);[126] regulatory SO_2 emission rates arising from State Implementation Plans (SIP); Title IV of the Clean Air Act Amendments; NO_X SIP Call trading program; Clean Air Act Reasonable Available Control Technology requirements and Title IV unit specific rate limits for NO_X; the Regional Greenhouse Gas Initiative; Renewable Portfolio Standards; New Source Review Settlements; and several state-level regulations affecting emissions of SO_2, NO_X, and mercury that are already in place or expected to come into force by 2017.

In contrast to the screening-level analyses described earlier, which are static analyses and do not account for interdependence of electric generating units in supplying power to the electric transmission grid, IPM accounts for potential changes in the generation profile of individual electric power facilities and consequent changes in market-level generation costs, as a result of the final rule. The model is dynamic in that the analysis covers a multiple-decade period with information and decisions in any specific period depending on the analysis information and optimization results for the entire analysis period. The model is also forward-looking in that it uses forecasts of future conditions to make decisions for the present. Finally, in contrast to the screening-level analyses in which EPA assumed either no pass through of compliance costs (facility and entity cost-to-revenue analyses discussed in Section IX.D.a.1) or full cost pass-through (analysis of potential electricity price effects, Section IX.D.b.1), IPM assesses price and revenue effects from increased costs in competitive wholesale electricity markets, where some recovery of compliance costs through increased electricity prices is possible but not guaranteed.

In performing analyses based on the IPM V4.10_MATS platform, EPA used as its baseline a projection of electricity markets and facility operations without the final rule requirements (baseline case). As discussed above, this baseline accounts for compliance with the recently promulgated Federal air rules. EPA then overlaid this baseline with the estimated compliance costs and other operating effects—downtime for installation of IM technologies at existing units and auxiliary energy requirement to operate cooling towers at new units—for regulated facilities under the policy case.

As discussed in Appendix P of the EPA report, the IPM V4.10_MATS platform models the electric power market over the 43-year period from 2012 to 2054. Within this total analysis period, EPA looked at shorter IPM analysis periods (run-year windows)[127] to assess the effect of the final rule on national and regional electricity markets. Specifically, to assess the impact of the final rule during the period when regulated facilities temporarily suspend their operation to install compliance technologies—the short-term effects analysis or the downtime effects analysis—EPA used results reported for the 2020 IPM run year, which represent an 8-year window of 2017 through 2024.[128] The incurrence of downtime may lead to higher electricity generation costs overall, as generating units at regulated facilities are taken out of service to complete technology installation and other generating units, presumably with higher production costs, are dispatched to meet electricity demand. Because of the potential resulting increase in electricity generation costs, it is

[124] In some instances, facility information has been updated to reflect known material changes in a facility's generating capacity since 2006.

[125] Facilities excluded from the IPM analysis include three facilities in Hawaii and one facility in Alaska (i.e., areas that are outside the geographic scope of the model), four on-site facilities that are not connected to the integrated electric transmission grid, four facilities excluded from the IPM baseline as the result of custom adjustments made by ICF, and 12 facilities that did not respond to the 316(b) survey.

[126] EPA's Cross-State Air Pollution Rule (CSAPR) was promulgated to replace EPA's Clean Air Interstate Rule (CAIR), which had been remanded to EPA in 2008. However, on December 30, 2011, the U.S. Court of Appeals for the D.C. Circuit stayed CSAPR pending judicial review and left CAIR in place. On August 21, 2012 the Court issued an opinion vacating CSAPR and again leaving CAIR in place pending development of a valid replacement. On March 29, 2013, the United States filed a petition asking the Supreme Court to review the D.C. Circuit's opinion. Nevertheless, as explained above, CAIR remains in effect at this time. In light of the continuing uncertainty on CAIR and CSAPR, EPA determined it would not be appropriate or possible at this time to adjust emission projections on the basis of speculative alternative emission reduction requirements in 2020. EPA expects that the decision vacating CSAPR and leaving CAIR in place has minimal effect on the results of the analysis conducted in support of the final rule.

[127] Due to the highly data- and calculation-intensive computational procedures required for the IPM dynamic optimization algorithm, IPM is run only for a limited number of years. Run years are selected based on analytical requirements and the necessity to maintain a balanced choice of run years throughout the modeled time horizon. Each run year represents adjacent years in addition to the run year itself.

[128] As discussed earlier in this document, for the cost and economic impact analyses, EPA assumed that electric generators will install IM technologies during the 5-year window of 2018 through 2022. Because this technology-installation window falls within the time period captured by the 2020 run year (i.e., 2017 through 2024), EPA judges that 2020 is an appropriate year to capture the effects of technology-installation downtime.

important to examine market-level effects during the period in which downtime would occur.

To assess the longer term effect of the final rule on electricity markets during the period after compliance technology is installed at all regulated facilities—the steady-state post-compliance period—EPA analyzed results reported for the IPM 2030 run year, which represents a 10-year window of 2025 through 2034.[129] Effects that may occur during this steady-state period include increased electricity production costs at regulated facilities and potential permanent losses in generating capacity from early retirement (closure) of generating units. Both effects may lead to higher overall electricity generation costs through not only the increased production cost in regulated facilities, but also through dispatch of higher production cost units to offset capacity losses, reflecting the general upward shift in production costs.[130]

EPA measured the impacts of the final rule as the difference between key economic and operational impact metrics between the baseline case and the policy case. All analysis results presented below are representative of modeled market conditions in the years 2017–2034. While costs are in 2011 dollars, they are reflective of costs in the modeled years and are not discounted to the start of EPA's analysis period of 2013.[131] In contrast to the earlier statement that the cost and economic impact analysis findings presented in this preamble may be underestimates because EPA assumed that no facilities with impoundments will install compliance technology, the market-based analysis presented in this section reflects the opposite assumption. Namely, despite the final rule's treatment of impoundments, for purposes of this analysis, none of the facilities with impoundments are treated as having closed-cycle cooling in the baseline. As a result, to the extent that some of these facilities may qualify as having closed-cycle recirculating systems in the baseline, and thus would not need to install compliance technology, the costs and economic impacts reported in this section may be overestimated.

i. Analysis Results for the Year 2030—To Reflect Steady State, Post-Compliance Operations

For the steady-state analysis (2030), EPA considered impact metrics of interest at three levels of aggregation: (1) Impact on national and regional electricity markets, (2) impact on the group of 520 regulated facilities modeled in IPM, and (3) impact on individual 520 regulated facilities.

Impact on National and Regional Electricity Markets

For the assessment of market-level impacts, EPA considered six output metrics: (1) Incremental capacity retirements (closures); (2) changes in capacity retirements as a percent of total baseline capacity (3) changes in new capacity additions; (4) changes in variable production costs per MWh, calculated as the sum of total fuel and variable O&M costs divided by net generation; (5) changes in total generation costs (fuel, variable O&M, fixed O&M, and capital); and (6) changes in wholesale electricity prices.

As shown in Exhibit IX–10, the final rule has small effects on the electricity market, on both the national and regional sub-market basis, in 2030. At the national level, the analysis shows a total net increase in retired capacity of approximately 1 GW, or less than 0.1 percent of the total baseline capacity in 2030 (capacity retirements are discussed in greater detail in the next section, Impact on Regulated Facilities as a Group). This 1 GW of net capacity loss reflects a combination of closures and avoided closures of generating units. ''Avoided closure'' means a generating unit that was projected to close in the baseline case but remains open in the policy case because of changes in the relative operating economics of generating capacity. In some instances an avoided closure can result in an avoided full facility closure. Overall, the final rule will lead to early retirement of approximately 4 GW of generating capacity and approximately 3 GW of avoided closure of capacity otherwise projected to retire by 2030, resulting in a net closure of approximately 1 GW of generating capacity. With only one exception, these retirements involve older, less efficient generating units with very low capacity utilization rates.

Five of the eight analyzed NERC regions record modest increases in retired capacity, with the largest increase, 0.8 percent of baseline retired capacity, projected to occur in TRE. One NERC region—SPP—avoids capacity closures, where 1.5 percent of capacity otherwise projected to retire in the baseline, becomes a more economically viable source of electricity in the policy case due to changes in the relative economics of electricity production across the full market, and thus avoids closure.[132] Consequently, the final rule is not expected to have a material ongoing effect on capacity availability and supply reliability at either the national or the NERC region level.

The 1 GW of retired capacity is replaced by new, more efficient, and less polluting capacity. Because the new capacity is more efficient and less costly to run than the retired capacity, it will run at a higher capacity utilization rate than the retired capacity; less new capacity is required to meet electricity demand than the retired capacity that it replaces. As shown in Exhibit IX–11, under the final rule, new capacity additions increase by 1 GW at the national level; this increase represents 0.5 percent of new baseline capacity and 0.1 percent of total baseline capacity (see Exhibit IX–10). This increase in new capacity is mostly comprised of combined cycle capacity followed by other non-steam capacity, with coal steam capacity additions remaining zero in both the baseline case and the policy case. Consequently, this analysis shows that the final rule is not likely to impede construction of new combined cycle and coal steam generating units.[133]

As reported in Exhibit IX–10, overall, the final rule has only a slight impact on electricity prices. For three out of eight NERC regions, electricity prices decline

[129] EPA expects this steady-state period to begin in the last year of the technology-installation window, i.e., 2022, and continue into the future. The 2022 analysis year is captured in the IPM 2020 run year, as opposed to the 2030 run year. However, because all analysis years represented by the 2030 run year (i.e., 2025–2034) fall outside the technology-installation window of 2018 through 2022, EPA judges that 2030 is an appropriate year to capture longer term, steady-state effects of the final rule.

[130] In seeking to minimize the cost of meeting electricity demand, IPM will tend to shift production away from regulated facilities that incur compliance costs, and will shift production to either non-regulated facilities, which incur no compliance costs, or to regulated facilities that incur relatively lower compliance costs. Any of these changes—whether a simple increase in production costs for previously dispatched units or changes in the profile of generating unit dispatch—mean increased total costs for electricity generation, compared to the pre-regulation baseline.

[131] In contrast, the social cost estimated in Section IX.C reflects the discounted value of compliance costs over the entire 51-year analysis period, as of 2013. Additionally, screening-level analyses presented in earlier sections are static analyses and do not account for interdependence of electric generating units in supplying power to the electric transmission grid. In contrast, IPM accounts for potential changes in the generation profile of steam electric and other units and consequent changes in market-level generation costs, as the electric power market responds to higher generation costs for steam electric units due to the final rule.

[132] Avoided closures may occur among facilities that incur no compliance costs under the final rule or for which compliance costs are low relative to the costs estimated for other regulated facilities.

[133] As described earlier in this preamble, under the new unit provision of the final rule, new units as defined at 125.92 include, stand-alone fossil fuel and combined cycle units. As described in Chapter 6 of the EA, the IPM analysis accounts only for compliance costs associated with new units. Further, EPA assigned these costs only to coal steam and combined cycle capacity.

slightly—by no more than $0.05 per MWh (0.1 percent) in TRE. Electricity prices increase in the remaining five NERC regions, with the largest increase, $0.29 per MWh (0.4 percent), occurring in NPCC. These very small estimated changes in electricity prices are essentially within the analytic ''noise'' of the electricity market modeling system.

At the national level, total generation costs increase by 0.3 percent of the baseline value—again, a very modest amount. Across regions, no NERC region records an increase in total costs exceeding 0.5 percent. The change in variable production costs ($/MWh)—a specific measure of the effect of the final rule on short-run electricity generation costs—is nearly zero with no NERC region recording a consequential change.

EXHIBIT IX–10—IMPACT OF THE FINAL RULE ON NATIONAL AND REGIONAL MARKETS, AT THE YEAR 2030

NERC region [a]	Total baseline capacity (GW)	Net changes in early retirements		Changes in variable costs		Changes in total costs		Changes in electricity price	
		GW	% of total baseline capacity	$2011/MWh	% of baseline	Mill 2011$	% of baseline	$2011/MWh	% of baseline
FRCC	68	0	0.30	−$0.03	−0.10	$51	0.30	−0.01	0.00
MRO	76	0	0.00	0.01	0.10	62	0.40	0.21	0.30
NPCC	73	0	0.50	0.00	0.00	28	0.20	0.29	0.40
RFC	237	0	0.10	0.01	0.00	157	0.30	0.15	0.20
SERC	274	0	0.10	0.02	0.10	182	0.30	0.08	0.10
SPP	59	−1	−1.50	0.02	0.10	31	0.30	−0.01	0.00
TRE	98	1	0.80	−0.01	0.00	48	0.30	−0.05	−0.10
WECC	220	0	0.00	0.00	0.00	9	0.00	0.03	0.00
Total	1,106	1	0.10	0.00	0.00	568	0.30	....	N/A

[a] FRCC (Florida Reliability Coordinating Council), MRO (Midwest Reliability Organization), NPCC (Northeast Power Coordination Council), RFC (ReliabilityFirst Corporation), SERC (Southeastern Electricity Reliability Council), SPP (Southwest Power Pool), TRE (Texas Reliability Entity), and WECC (Western Electricity Coordinating Council).

EXHIBIT IX–11—IMPACT OF THE FINAL RULE ON NEW CAPACITY (GW), AT THE YEAR 2030

Capacity type	Baseline value	Final rule		
		Value	Difference	% Change
Coal Steam	0	0	0	NA
Combined Cycle	75	76	1	0.8
Combustion Turbine	6	6	0	0.0
Hydro	0	0	0	NA
Nuclear	0	0	0	NA
O/G Steam	0	0	0	NA
Other Non-Steam [a]	25	25	0	0.1
Other Steam [b]	9	9	0	0.0
Total	114	115	1	0.5

[a] Other non-steam capacity includes wind, solar, pumped storage, and fuel cell.
[b] Other steam capacity includes biomass, geothermal, municipal solid waste, fossil waste, landfill gas, tires, and non-fossil waste.

Impact on Regulated Facilities as a Group

EPA used the same IPM V4.10_MATS analysis results for 2030 as those used to assess market-level impacts described above; however, this analysis considers the effect of the final rule only on regulated facilities modeled in IPM (i.e., 520 facilities). For this analysis, EPA considered four output metrics: (1) Incremental capacity closures; (2) changes in capacity closures as a percent of total baseline capacity; (3) changes in total generation; and (4) changes in variable production costs per MWh.

As shown in Exhibit IX–12, for the group of regulated facilities, the impact of the final rule is overall slightly greater than that observed over all generating units in the IPM universe (i.e., market-level analysis discussed in the preceding section). This difference is due to the fact that in the electricity market as a whole, impacts on regulated facilities, which become less competitive compared to facilities that do not incur compliance costs, are offset by changes in capacity and energy production at the other electric power facilities. Nevertheless, the impact on the group of regulated facilities remains small. For instance, while there is essentially no change in total available capacity for the overall electricity market at the national level, for the group of regulated facilities, total available capacity falls by only 0.4 percent (2 GW). At the regional level, five NERC regions incur loss in total capacity, with the largest percentage loss of 2.8 percent and the largest absolute loss of 0.9 GW occurring in the NPCC region.

The 2 GW of capacity loss at regulated facilities reflects a combination of closures and avoided closures of generating units in the universe of regulated facilities. Some unit closures result in full facility closures (i.e., all generating units at a facility close), while others result in only partial facility closures (i.e., some, but not all, generating units at a facility close). For avoided closures, a generating unit projected to close in the baseline case but remains open under the policy case, in some instances resulting in an avoided full facility closure. Overall, 22 generating units close (4 GW) and 12 generating units avoid closure (2 GW) in the policy case, resulting in net closure of 10 generating units (approximately 2 GW) in Electricity Market Analysis—Final Rule analysis. The 22 generating unit closures reflect retirement of nine units at six full-closure facilities (2 GW) and retirement of 13 units at six partial-closure facilities (2 GW). With only one exception, these retirements involve older, less efficient generating units with very low capacity utilization rates.

At the national level, for the group of regulated facilities, total generation at regulated facilities declines by less than 2 GWh or approximately 0.1 percent of baseline generation in these facilities. The MRO and SERC regions record slight increases in generation essentially amounting to zero percent of baseline generation at regulated facilities in these regions, with the remaining five NERC regions recording a reduction in electricity generation of no more than 0.4 percent in FRCC.

Over all regulated facilities, there is essentially no change in variable production costs ($/MWh) at the national level, while at the NERC region level, the change does not exceed 0.2 percent for any of the regions. These findings of very small effects confirm EPA's assessment that the assessed capacity closures among regulated facilities are of little economic consequence at both the national and regional levels.

EXHIBIT IX–12—IMPACT OF ELECTRICITY MARKET ANALYSIS OPTIONS ON THE GROUP OF REGULATED FACILITIES, AT THE YEAR 2030

NERC region [a]	Baseline capacity (MW)	Net change in early retirements/closures		Change in generation		Change in variable production cost	
		Capacity (MW)	% of baseline	GWh	% of baseline	$2011/MWh	% of baseline
FRCC	30,794	203	0.7	−527	−0.4	−0.08	−0.2
MRO	31,747	0	0.0	30	0.0	0.01	0.1
NPCC	30,977	855	2.8	−25	0.0	0.00	0.0
RFC	126,905	223	0.2	−619	−0.1	0.00	0.0
SERC	142,840	476	0.3	3	0.0	0.02	0.1
SPP	24,487	−530	−2.2	−411	−0.3	0.01	0.0
TRE	38,378	808	2.1	−163	−0.1	−0.02	−0.1
WECC	34,788	0	0.0	−8	0.0	0.00	0.0
Total	460,917	2,035	0.4	−1,721	−0.1	0.00	0.0

[a] FRCC (Florida Reliability Coordinating Council), MRO (Midwest Reliability Organization), NPCC (Northeast Power Coordination Council), RFC (ReliabilityFirst Corporation), SERC (Southeastern Electricity Reliability Council), SPP (Southwest Power Pool), TRE (Texas Reliability Entity), and WECC (Western Electricity Coordinating Council).

Impact on Individual Regulated Facilities

Results for the group of 520 regulated facilities as a whole may mask shifts in economic performance among individual facilities incurring compliance costs under the final rule. To assess potential facility-level effects, EPA analyzed facility-specific changes between the baseline case and the final rule for the following metrics: (1) Capacity utilization (defined as annual generation (in MWh) divided by [capacity (MW) times 8,760 hours]) (2) electricity generation, and (3) variable production costs per MWh.

Exhibit XI–13 presents the estimated number of regulated facilities with specific degrees of change in operations and financial performance. Under the final rule, this analysis shows that most facilities experience only slight effects—i.e., no change or less than a 1 percent reduction or 1 percent increase. Only six facilities are estimated to incur a reduction in capacity utilization and 13 facilities a reduction in generation of at least 1 percent, with only five facilities estimated to incur an increase in variable production costs per MWh of at least 1 percent. These facilities represent approximately 1 percent of 520 regulated facilities analyzed in IPM.

EXHIBIT IX–13—IMPACT OF THE ELECTRICITY MARKET ANALYSIS—FINAL RULE ON INDIVIDUAL REGULATED FACILITIES AT THE YEAR 2030

[Number of regulated facilities with indicated effect]

Economic measures	Reduction			No Change	Increase			N/A [b c]
	≥3%	≥1 and <3%	<1%		<1%	≥1 and <3%	≥3%	
Change in Capacity Utilization [a]	1	5	45	340	35	2	0	92
Change in Generation	9	4	37	345	29	2	2	92
Change in Variable Production Costs/MWh	2	1	70	86	242	4	1	114

[a] The change in capacity utilization is the difference between the capacity utilization percentages in the baseline and policy cases. For all other measures, the change is expressed as the percentage change between the baseline and post-compliance values.

[b] Facilities with status changes in either the baseline case or the policy case were excluded from these calculations. Specifically, there are 17 full baseline facility closures, 59 partial baseline facility closures, four avoided partial facility closures, six partial policy facility closures, and six partial policy facility closures.

[c] The change in variable production cost per MWh could not be developed for 22 facilities with zero generation in either the baseline case or the policy case.

ii. Analysis Results for 2020—To Capture the Effect of Technology-Installation Downtime

This section presents market-level results for the final rule for the 2020 IPM run year, which represents 2017 through 2024. As discussed above, this IPM run year captures the period when regulated facilities are expected to install compliance technologies under the final rule. Of particular importance as a potential impact, the additional downtime from installation of compliance technologies could manifest as increased electricity production costs resulting from the dispatch of higher-production-cost generating units during the period when units are taken offline to install compliance technologies. Because these effects are of most concern in terms of potential impact on national and regional electricity markets, this section presents results only for the overall electricity market and does not present results for the subset of regulated facilities.

As shown in Exhibit IX–14, the estimated effects of technology-installation downtime under the final rule are small. At the national level, total production costs increase by 0.4 percent. At the regional level, these costs increase in all NERC regions, with MRO and SPP recording the largest increase of 0.6 percent.

At the national level, variable production costs ($/MWh) increase by approximately 0.2 percent. While the effect on variable production costs varies across NERC regions, this effect is small overall, with the largest increase of less than 0.4 percent occurring in FRCC. While electricity prices increase in all NERC regions, the magnitude of that increase is generally small, ranging from $0.15 per MWh (0.3 percent) in MRO and WECC to $0.56 per MWh (0.9 percent) in FRCC.

EXHIBIT IX–14—SHORT-TERM EFFECT OF TECHNOLOGY INSTALLATION DOWNTIME ON NATIONAL ELECTRICITY MARKET UNDER THE FINAL RULE—2020

NERC Region[a]	Change in generation		Change in variable production cost		Change in total costs		Change in electricity price	
	2011$/MWh	% of baseline	2011$/MWh	% of baseline	Million 2011$	% of baseline	2011$/MWh	% of baseline
FRCC	−108	0.0	0.13	0.4	51	0.5	0.56	0.9
MRO	52	0.0	0.03	0.2	64	0.6	0.15	0.3
NPCC	−88	0.0	0.05	0.2	31	0.3	0.18	0.3
RFC	447	0.0	0.03	0.1	164	0.4	0.19	0.4
SERC	−369	0.0	0.04	0.1	185	0.4	0.27	0.6
SPP	−53	0.0	0.08	0.3	56	0.6	0.18	0.4
TRE	0	0.0	0.08	0.3	64	0.5	0.21	0.4
WECC	33	0.0	0.04	0.2	39	0.1	0.15	0.3
Total	−88	0.0	0.05	0.2	652	0.4		N/A

[a] FRCC (Florida Reliability Coordinating Council), MRO (Midwest Reliability Organization), NPCC (Northeast Power Coordination Council), RFC (ReliabilityFirst Corporation), SERC (Southeastern Electricity Reliability Council), SPP (Southwest Power Pool), TRE (Texas Reliability Entity), and WECC (Western Electricity Coordinating Council).

EPA recognizes any capacity outages estimated to occur in conjunction with installation of compliance technologies at existing units will require outage coordination by the system operator or other planning authority. Where possible, these outages would be scheduled in concurrence with normal scheduled maintenance outages. Permit authorities are provided flexibility to tailor compliance timelines. This flexibility will ensure that any adverse impact on local electric reliability as a result of this rule will be avoided. Facilities would receive workable construction schedules from permit writers that will allow schedule outages for installation without adversely affecting electric supply reliability.

2. Manufacturers

This section presents EPA's estimated economic impacts on manufacturers for the final rule and the other options EPA considered. These analyses assess the impact of regulatory requirements on the financial performance of regulated facilities (facility-level analysis) and the entities that own them (entity-level analysis). Similarly to the electric generators analysis, for the manufacturers facility-level and entity-level analyses, the Agency assumed that facilities would pass none of their compliance costs forward to customers as price increases, i.e., all compliance costs will be absorbed by regulated facilities and their parent entities. For details on the cost-pass-through (CPT) analysis for information on this assumption, see the EA, Appendix K. EPA developed and used sample weights to extrapolate impacts assessed initially at the level of a sample of facilities to the full population of regulated facilities. For information on the development and use of sample weights, see EA Appendix H.

a. Facility-Level Impact Analysis for Manufacturers

EPA conducted two separate facility-level analyses for manufacturers: (1) A stand-alone cost-to-revenue screener analysis and (2) a facility closure and financial stress short of closure test. For the cost-to revenue screener test, shown in Exhibit IX–15, EPA divided the after-tax, annualized compliance cost by facility-level revenue. Under the final rule, EPA found that of 500 Primary Manufacturing Industry facilities, 496 incur costs less than one percent of revenue, four incur costs between one and three percent, and none incur costs greater than 3 percent. For the nine Other Industries facilities, EPA estimated that eight facilities would incur costs less than one percent and one would incur costs between one and three percent of revenue. For Proposal Option 4, all Primary Manufacturing Industry facilities (500 facilities) and Other Industry facilities (nine facilities) incur costs less than one percent of revenue. Under Proposal Option 2, 491 Primary Manufacturing Industry facilities incur costs less than one percent and nine facilities incur costs between one and three percent, while seven Other Industry facilities incur costs less than one percent, one facility incurs costs between one and three percent, and one facility incurs costs greater than three percent.

EXHIBIT IX–15—FACILITY-LEVEL COST-TO-REVENUE ANALYSIS RESULTS

Option	Number of facilities with a cost-to-revenue ratio of [a]		
	<1%	≥1 and <3%	≥3%
Primary manufacturing industries			
Proposal Option 4	500	0	0
Final Rule	496	4	0
Proposal Option 2	491	9	0
Other industries			
Proposal Option 4	9	0	0
Final Rule	8	1	0
Proposal Option 2	7	1	1

[a] EPA conducted this analysis for 579 facilities in the Primary Manufacturing Industries and 10 facilities in the Other Industries. Note, these facility counts and analysis exclude facilities identified as baseline closures in the severe impact analysis, which is described below.

For the second analysis, EPA assessed how compliance costs would likely affect financial performance and condition of the 509 manufacturers [134] using two measures: (1) Facility closures (severe impacts) and associated losses in revenue and employment, and (2) financial stress short of closure (moderate impacts).

For the analysis of severe impacts, EPA identified a facility as a regulatory closure if it would have operated under baseline conditions but would not be financially viable under the new regulatory requirements and the costs of the final rule leading to that finding exceeded a threshold of 0.1 percent of revenue. Specifically, the Agency examined the facility's going-concern value before and after meeting regulatory requirements. EPA used a discounted cash flow framework in which after-tax cash flow is discounted at an estimated cost of capital to calculate the going concern value of the facility.[135] In conjunction with the discounted cash flow analysis, EPA tested whether annualized costs exceeded 0.1 percent of revenue by dividing the after-tax, annualized total compliance cost by facility-level revenue. If this analysis found that the facility's business value would become negative as a result of estimated compliance costs *and* the annualized cost of compliance exceeded 0.1 percent of revenue, EPA classified the facility as a regulatory closure.

For facilities estimated not to close under the severe-impact test, EPA conducted a moderate-impact test to assess whether any would experience financial stress short of closure as the result of regulatory requirements (e.g., higher costs of capital borrowing). EPA used two financial performance measures to test for occurrence of financial stress: (1) Interest coverage ratio and (2) pre-tax return on assets. The Agency compared these measures before and after compliance with regulatory requirements against industry-specific performance thresholds for the two financial measures. If both measures for a facility exceeded the threshold in the baseline, and at least one measure fell below the threshold in the post-compliance case, EPA counted this as a moderate impact based on the rule.

Exhibit IX–16 presents the results from the severe-impact and moderate-impact analyses. EPA estimated that no facilities would be at risk of closure as a result of the final rule and that 12 facilities could experience financial stress short of closure. For Proposal Option 4, EPA also estimated no closures, while moderate impacts are significantly lower, estimated at two facilities. Under Proposal Option 2, EPA estimated that one facility would be at risk of closure, while the moderate impact finding is the same as for the final rule: 12 facilities. Again, this analysis is conducted assuming that all the costs are borne by the facility and cannot be passed along, an assumption that is highly unlikely to be true, as many of these facilities are in industries where there is some market power and barriers to entry. Thus, these tests present worst case scenario results.

EXHIBIT IX–16—FACILITY IMPACTS AND COMPLIANCE COSTS FOR MANUFACTURERS [d]

	Proposed option 4	Final rule	Proposed option 2 [c]
Primary manufacturing industries [a]			
Number of Facilities Operating in Baseline	500	500	500
Number of Closures (Severe Impacts)	0	0	1
Percentage of Facilities Closing	0%	0%	0%
Number of Facilities with Moderate Impacts	2	12	12
Percentage of Facilities with Moderate Impacts	1%	3%	3%
Other industries [b]			
Number of Facilities Operating in Baseline	9	9	9
Number of Closures (Severe Impacts)	0	0	0

[134] This is a sample-weighted estimate of the number of manufacturers, calculated using economic weights. This number excludes 70 facilities estimated to be at substantial risk of financial failure regardless of any additional financial burden that might result from the final rule or other options considered in development of this rule. For details see EA Appendix H.

[135] This after-tax cash flow analysis conducted for manufacturers is similar in concept to the cash flow analysis conducted for electric generators through the IPM analysis.

EXHIBIT IX–16—FACILITY IMPACTS AND COMPLIANCE COSTS FOR MANUFACTURERS [d]—Continued

	Proposed option 4	Final rule	Proposed option 2 [c]
Percentage of Facilities Closing	0%	0%	0%
Number of Facilities with Moderate Impacts	0	0	0
Percentage of Facilities with Moderate Impacts	0%	0%	0%

[a] Primary Manufacturing Industries include facilities in the Aluminum, Chemicals and Allied Products, Food and Kindred Products, Paper and Allied Products, Petroleum Refining, and Steel industries.
[b] Other Industries include cooling water-dependent facilities in industries whose principal operations lie in businesses other than the electric power industry or the Primary Manufacturing Industries.
[c] Under Proposal Option 2, the percentage of facilities closing is 0.3 percent.
[d] The analysis assumes no cost pass through.

b. Entity-Level Impact Analysis

EPA also examined the impact of regulatory requirements on entities that own regulated manufacturers facilities. An entity that owns multiple facilities could be adversely affected because of the cumulative burden of regulatory requirements the facilities face. For this analysis, a parent entity is the domestic parent entity with the largest ownership share in a regulated facility. For each identified parent entity, EPA aggregated facility-level, annualized, after-tax compliance costs to the level of the parent entity and compared these entity-level costs to entity-level revenue. Similarly to electric generators, EPA used cost-to-revenue thresholds of 1 and 3 percent as thresholds for categorizing levels of impacts.

EPA considered two cases, based on two sets of entity-level. These cases, which are described in the EA, Appendix H, provide a range of estimates for the number of entities incurring compliance costs and the costs incurred by any entity owning a regulated facility. EPA conducted this analysis for 509 facilities in the primary manufacturing industries and 12 facilities in other industries.[136] For information on the methodology used for the entity-level cost-to-revenue analysis, see the EA, Chapter 5.

Exhibit IX–17 presents the results from the entity-level analysis for these two cases. EPA estimated that between 120 and 337 entities own 521 regulated facilities. Under the final rule, between 90 and 95 percent of all entities are estimated to incur compliance costs of less than 1 percent of revenue. This is true also for Proposal Option 2. Under Proposal Option 4, more entities are expected to incur compliance costs of less than 1 percent of revenue (between 94 and 96 percent of all entities).

EXHIBIT IX–17—ENTITY-LEVEL COST-TO-REVENUE ANALYSIS RESULTS

Option	Not analyzed due to lack of revenue information		Number of entities with a cost-to-revenue ratio of					
			< 1%		≥ 1% and < 3%		≥ 3%	
	#	%	#	%	#	%	#	%
Case 1: Lower bound estimate of number of entities that own regulated facilities; upper bound estimate of total compliance costs that an entity may incur [b]								
Proposal Option 4	5	4	113	94	2	2	0	0
Final Rule	5	4	108	90	6	5	1	1
Proposal Option 2	5	4	108	90	6	5	1	1
Case 2: Upper bound estimate of number of entities that own regulated facilities; lower bound estimate of total compliance costs that an entity may incur [c]								
Proposal Option 4	12	4	324	96	1	[a] 0	0	0
Final Rule	12	4	319	95	6	2	0	0
Proposal Option 2	12	4	319	95	6	2	0	0

[a] The percentage of entities with impacts greater than or equal to 1 percent and less than 3 percent is less than 0.5 percent.
[b] The total number of entities under Case 1 is 120.
[c] The total number of entities under Case 2 is 337.

E. Employment Effects

To study employment effects of this rule, EPA considered the potential effects of the final rule, focusing on the impacts of meeting compliance requirements in the directly regulated industry sectors: The Electric Power Industry, and selected Primary Manufacturing Industries, including Aluminum, Chemicals and Allied Products, Food and Kindred Products, Paper and Allied Products, Petroleum Refining, and Steel Manufacturing.

When the economy is at full employment, an environmental regulation is unlikely to have much impact on net overall U.S. employment; instead, labor would primarily be shifted from one sector to another. These shifts in employment impose an opportunity cost on society, approximated by the wages of the employees, as regulation diverts workers from other activities in the economy. In this situation, any effects on net employment are likely to be transitory as workers change jobs (e.g., some workers may need to be retrained or require time to search for new jobs,

[136] This is a sample-weighted estimate of the number of manufacturer facilities, calculated using technical weights. This number excludes 67 facilities estimated to be at substantial risk of closure regardless of any additional financial burden that might result from the regulatory options under consideration.

while shortages in some sectors or regions could bid up wages to attract workers).

On the other hand, if a regulation comes into effect during a period of high unemployment, a change in labor demand due to regulation may affect net overall U.S. employment because the labor market is not in equilibrium. Schmalansee and Stavins [137] point out that net positive employment effects are possible in the near term when the economy is at less than full employment due to the potential hiring of idle labor resources by the regulated sector to meet new requirements (e.g., to install new equipment) and new economic activity in sectors related to the regulated sector. In the longer run, the net effect on employment is more difficult to predict and will depend on the way in which the related industries respond to the regulatory requirements. As Schmalansee and Stavins note, the magnitude of the effect on employment could vary over time, region, and sector, and positive effects on employment in some regions or sectors could be offset by negative effects in other regions or sectors. For this reason, they urge caution in reporting partial employment effects because it can ''paint an inaccurate picture of net employment impacts if not placed in the broader economic context.''

In that spirit, unlike the analysis for the proposed rule, for the final rule EPA is not estimating quantitative employment impacts and instead, including only a qualitative discussion. The methods used at proposal were not sufficiently robust, largely because they relied on an input-output analysis that assumed fixed production relationships and used historical data to estimate the labor and other inputs required for compliance with the rule. Since publication of the proposed rule, EPA has concluded that input-output analysis is inappropriate for assessing employment impacts of national-level regulations. Input-output models are static, do not include prices, and assume the supply of all inputs is inexhaustible. They do not model a wide variety of adjustments that are expected to occur over time, such as changes in production processes, technology or trade patterns.[138] After reviewing the public comments EPA received on the proposed rule, the Agency concludes that the commenters have not identified any specific improvements to the employment analysis of the proposed rule. Thus, today's final rule EA includes a qualitative discussion highlighting the variety of potential adjustments in the labor market that may follow the rulemaking.

To elaborate on the difficulty of deriving high quality estimates of how environmental regulations will impact net employment, the task requires consideration of labor demand in both the regulated and environmental protection sectors, as well as labor supply more generally. Economic theory predicts that the net effect of an environmental regulation on labor demand in regulated sectors could be positive or negative; the direction of the outcome depends on the magnitude of output and substitution effects, explained further in the EA. Peer-reviewed econometric studies that use a structural approach, applicable to overall net effects in the regulated sectors, indicate that such effects, whether positive or negative, have been small and have not affected employment in the national economy in a significant way (Berman and Bui 2001, Morgenstern, Pizer and Shih 2002). Effects on labor demand in the environmental protection sector seem likely to be positive.

In aggregate, the environmental protection sector is likely to experience a temporary increase in jobs created as more compliance technology systems are designed, manufactured, and installed attributable to the final rule. In addition, because of regional variation in consumption patterns and the presence of regulated facilities and supporting industries, short- and long-run employment effects likely will vary across the United States. It is possible that positive net employment effects will occur in the near term due to the hiring of idle labor resources by the regulated sectors to plan for and meet new technology control requirements rather than diverting workers from other productive employment. However, it is also possible that in the long run, as the economy returns to full employment, any changes in employment in the regulated sectors due to the final rule will be offset by employment changes in other sectors. These dynamics compound the uncertainty in estimating employment effects for a substantial number of years into the future.

Even if regulated facilities are able to reduce the impact of regulatory requirements by changing their production processes in the post-rule environment, production costs may still be higher compared to those before the rule. As a result, regulated facilities may seek to increase their product prices in response to the higher production costs. For example, attempts by electric generators to recover increases in electricity generation costs, however small, are likely to result in higher electricity rates. The impact of this increase will vary by region, customer group (e.g., industrial, commercial, transportation, and residential), and by industry, depending on the electricity-use intensity.[139] Further, the extent to which electric generators are able to pass their costs to consumers through higher electricity rates, will vary by region. Specifically, electric generators operating in regions where electricity prices remain regulated under the traditional cost-of-service rate regulation framework may be able to recover compliance cost-based increases in increased rates.[140] However, cost recovery is less certain for electric generators operating in States where electric power generation has been deregulated, and will depend on the competitive circumstances of specifically affected facilities.

Overall, the long-run changes in employment will likely depend on how the electric power industry, primary manufacturing industries, and other industries adjust in response to the new regulatory requirements, and on the upstream and downstream effects of those adjustments on the rest of the economy, as well as the overall state of the economy and labor markets. The long-run employment effects in the directly affected sectors will depend on a number of economic factors. These factors include changes in labor requirements to operate the infrastructure in general and compliance technology in particular at regulated facilities, the potential to change production processes to become less dependent on cooling water, availability of alternative technologies to meet compliance requirements, and changes in demand for the outputs of the directly affected sectors. Because

[137] Schmalansee, Richard, and Robert N. Stavins. ''A Guide to Economic and Policy Analysis of EPA's Transport Rule.'' White paper commissioned by Exelon Corporation, March 2011 (Docket EPA–HQ–OAR–2011–0135–0054).

[138] For a discussion of input-output models see Chapter 8 of the EPA Handbook on the Benefits, Costs, and Impacts of Land Cleanup and Reuse (2011).

[139] See the EA *Chapter 6: Electricity Market Analysis* for assessment of the impacts of increased production costs on wholesale electricity prices and *Chapter 4: Economic Impact Analysis—Electric Generators* for analyses of the impacts on retail rates by customer group.

[140] However, even for electric generators operating under traditional rate regulation, the recovery of cost increases through increased rates is not certain, and will depend on additional factors such as the facility ownership structure and operating model, approval of public utility commissions, and the importance and role of market mechanisms in dispatching production of electricity across generating units. See *Chapter 2A* of the EA for additional discussion.

these and many other interrelated factors include data and methodology limitations, it is difficult to fully assess the employment impacts of the final rule. However, based on the available evidence from several peer-reviewed econometric studies mentioned above that are applicable to net effects in the regulated sectors and that closed-cycle recirculating systems was rejected as national BTA for entrainment, EPA expects that employment impacts of today's rule are not likely to be substantial.

X. Benefits Analysis

A. Introduction

This section presents EPA's estimates of the national environmental benefits of the final existing facilities rule and other options considered by EPA. This section describes how EPA calculated values for those benefits it could monetize. EPA did not rely on the results of its stated preference survey in estimating the benefits of today's rule. It also presents descriptive information for those benefits for which EPA could not develop a monetary value. The benefits EPA assessed occur because of reductions in impingement and entrainment at cooling water intake structures affected by the rulemaking and changes in greenhouse gas emissions at regulated facilities. Impingement occurs where fish and other aquatic life are trapped on equipment as they enter the cooling water intake structure. Entrainment occurs where aquatic organisms, including eggs and larvae, are drawn into the cooling system, passed through the heat exchanger, and discharged back into the source waterbody. Impingement and entrainment kill or injure large numbers of aquatic organisms across all life stages. On the basis of entrainment data presented in facility studies, EPA assumes a mortality rate of 100 percent for entrained individuals. Mortality is then reduced on the basis of the efficiency of technology in place in reducing mortality rates, or by reducing levels of impingement and entrainment.[141] By reducing impingement mortality and entrainment, the final existing facilities rule is likely to increase the number of fish, shellfish, and other aquatic organisms in affected water bodies resulting in healthier aquatic environments. In turn, this healthier aquatic environment directly improves welfare for individuals using the affected aquatic resources, generating *use benefits* such as increases in the value of recreational and commercial fisheries or increases in property values. Reductions in impingement mortality and entrainment also improve welfare for individuals without use of the affected resources, generating *nonuse benefits,* such as improved ecosystem function and resource bequest values. Section D provides an overview of the types and sources of benefits EPA anticipated, how EPA estimated these benefits, and the level of benefits that the final rule and other options EPA considered for the rule would achieve.

EPA derived national benefit estimates for the final rule and other options considered from a series of regional studies representing a range of waterbody types and aquatic resources. Section B provides detail on the regional study design. Section C describes the impingement and entrainment effects and Section D presents the national benefits estimates.

The methodologies used to estimate benefits are largely built on those used to estimate benefits for the remanded Phase II and Phase III and the proposed existing facilities rules. In addition to updating these analyses, EPA more fully investigated the effects of impingement mortality and entrainment on T&E species, incorporated benefits from greenhouse gas reductions, and improved its estimation of nonuse benefits. The Benefits Analysis document for the final existing facilities rule (referred to as the BA) provides detailed descriptions of the new methodologies EPA used to analyze the benefits of regulatory options, and provides references to (i) Part A of the 2004 Regional Benefits Analysis for the Final Section 316(b) Phase II Rule, and (ii) Part A of the 2006 Regional Benefits Analysis Document for the Final Section 316(b) Phase III Existing Facilities Rule for analyses using similar methodologies.

The BA provides EPA's benefit estimates for the final rule and considered options. EPA relied on information collected in the 2000 section 316(b) industry surveys (the Industry Screener Questionnaire (SQ) and the Detailed Industry Questionnaire (DQ)) on cooling water systems and intake structures already in place to estimate the number of regulated facilities under regulatory options considered for the final existing facilities rule. For the analysis of regulated electric generators, EPA used information from 656 regulated electric generating facilities that responded to the section 316(b) industry surveys on cooling water systems and intake structures already in place. Because the DQs were sent to a sample of the manufacturing industries that use cooling water, the respondents were assigned sample weights designed to represent other facilities in other manufacturing industries that were not covered in the survey. All regulated facilities have a DIF of at least 2 mgd. EPA estimated regional benefits from the sample of facilities for which EPA has sufficient DQ information to estimate the environmental impacts of regulatory options. The environmental impacts from the set of explicitly analyzed facilities were then extrapolated to the universe of facilities in a region using statistical weights developed for this analysis. National benefits are estimated as the sum of the regional benefits.

As described above at Section IX, the findings presented in this section assume that all facilities with impoundments will qualify as having closed-cycle recirculating systems in the baseline. For purposes of this analysis, EPA did not estimate IM&E reductions for these facilities under the final rule and other options considered; however, these facilities remain subject to today's rule and are assigned administrative costs. To the extent that some of these facilities do not qualify as having closed-cycle cycle recirculating systems in the baseline, the monetized benefits reported in this section may be underestimated. EPA notes that the vast majority of these facilities occur in the Inland benefits region. Any underestimation in monetized benefits due to the treatment of facilities with impoundments is likely to be minor because commercial fishing benefits and nonuse benefits are not estimated for the Inland region.

B. Regional Study Design

EPA evaluated the benefits of today's rule in seven study regions.[142] Regions were defined on the basis of ecological similarities within regions (e.g., freshwater versus marine, similar communities of aquatic species), and on characteristics of commercial and recreational fishing activities. The seven study regions are: California,[143] North Atlantic, Mid Atlantic, South Atlantic, Gulf of Mexico, Great Lakes, and Inland. The five coastal regions EPA identified (California, North Atlantic, Mid-Atlantic, South Atlantic, and Gulf of Mexico) correspond to those of the

[141] See the discussion in Section III on entrainment mortality data and assumptions.

[142] Benefits associated with changes in greenhouse gas emissions were estimated for the nation as whole.

[143] The California region includes facilities in State of California and four facilities in Hawaii. No coastal facilities are in Oregon, and one facility in Washington is classified as a baseline closure.

National Oceanic and Atmospheric Administration's National Marine Fisheries Service. The Great Lakes region includes Lake Ontario, Lake Erie, Lake Huron (including Lake St. Clair), Lake Michigan, Lake Superior, and the connecting channels (Saint Mary's River, Saint Clair River, Detroit River, Niagara River, and Saint Lawrence River to the Canadian border) as defined in 33 U.S.C. 1268, Sec. 118(a)(3)(b). The Inland region includes all remaining facilities that withdraw water from freshwater lakes, rivers, and reservoirs, including inland facilities in coastal states. Notably, of the 435 facilities that are on freshwater streams or rivers, 30 percent (132) have average actual intake flow that is greater than 5 percent of the mean annual flow of the source waters, which is a significant amount of the source water flow. During periods of low river flow, or during periods of higher than average withdrawals of cooling water, the proportionate withdrawal of source waters could be much higher. Thus, the potential for adverse environmental impacts could increase dramatically during these periods. The number and total operational intake flow of all 316(b) facilities by study region are presented in Exhibit X–1.

EXHIBIT X–1—NUMBER OF SURVEYED FACILITIES AND TOTAL MEAN OPERATIONAL FLOW, BY REGION

Region	Number of surveyed facilities [a]	Flow (billions of gallons per day)		
		Non-recirculating facilities [b]	Recirculating facilities	Total flow
California [c]	21	10.65	0.00	10.65
Great Lakes	50	16.24	0.24	16.47
Inland [d]	566	107.56	18.06	125.62
Mid-Atlantic	46	24.69	0.07	24.76
Gulf of Mexico	22	10.14	0.05	10.18
North Atlantic	21	5.93	0.00	5.93
South Atlantic	12	5.91	0.05	5.96
All Regions	738	181.12	18.46	199.58

[a] This table presents unweighted facility counts and flow for surveyed facilities (excluding baseline closures). The regional study design for the benefits analysis uses weights based on flow rather than facility counts. EPA did not develop weighted facility counts by benefits region. The "All Regions" total of 738 surveyed facilities includes 532 electric generating facilities and 206 manufacturing facilities, excluding baseline closures. The total (weighted) estimated universe of facilities, excluding baseline closures, is 1,065 facilities.

[b] Recirculating facilities are facilities with closed-cycle cooling or impoundments that qualify as closed-cycle cooling. Non-recirculating facilities include facilities with CWIS classified as once-through.

[c] The California region includes four facilities in Hawaii. There are no coastal facilities in Oregon and the one coastal facility in Washington is classified as a baseline closure.

[d] A facility in Texas has intakes in both the Inland and Gulf of Mexico regions. It is included in the Inland region in the table to prevent the double counting of facilities.

EPA obtained estimates of regional impingement mortality and entrainment by extrapolating impingement mortality and entrainment observed at 98 facilities with impingement and entrainment studies (model facilities) to all regulated facilities in the same region. EPA used regional estimates to more accurately estimate impacts by accounting for differences in ecosystems, aquatic species, and characteristics of commercial and recreational fishing activities across regions. Extrapolation was conducted on the basis of AIF reported for the period 1996–1998 by facilities in response to EPA's Section 316(b) Detailed Questionnaire and Short Technical Questionnaire. Chapter 3 of the BA provides details of the extrapolation procedure. Because the goal of the analysis was to provide estimates of impingement mortality and entrainment at regional and national scales, EPA recognizes that these averages may not reflect the substantial variability at individual facilities. In spite of this variability, EPA determined that this extrapolation is a reasonable basis for developing estimates of regional- and national-level benefits for the purposes of the final existing facilities rule.

C. Physical Impacts of Impingement Mortality and Entrainment

EPA based the benefits analysis on facility-provided impingement mortality and entrainment monitoring data. Facility data consist of records of impinged and entrained organisms sampled at intake structures and include organisms of all ages and life stages. Sampling protocols were not standardized across facilities. Facility protocols differed in sampling methods and equipment used, the number of samples taken, sampling duration, and the unit of time and volume of intake flow used to express impingement mortality and entrainment. To standardize estimates across facilities, EPA converted sampling counts into annual impingement mortality and entrainment. Using standard fishery modeling techniques,[144] EPA constructed models that combined facility-derived impingement mortality and entrainment counts with life history data from the scientific literature to derive annual estimates of the following:

• Individuals—the number of individual organisms impinged and entrained by facility intakes. Under this metric, eggs, larvae, juvenile, and adult organisms are counted as equivalent individuals.

[144] Ricker, W.E. 1975. Computation and interpretation of biological statistics of fish populations. Fisheries Research Board of Canada, Bulletin 191; Hilborn, R. and C.J. Walters. 1992. Quantitative Fisheries Stock Assessment, Choice, Dynamics and Uncertainty. Chapman and Hall, London and New York; Quinn, T.J., II. and R.B. Deriso. 1999. Quantitative Fish Dynamics. Oxford University Press, Oxford and New York; Dixon, D.A. 1999. Catalog of Assessment Methods for Evaluating the Effects of Power Plant Operations on Aquatic Communities. Electric Power Research Institute (EPRI) Final Report. Report number TR–112013.

- A1Es (age-one equivalent losses)—the number of individual organisms of different ages impinged and entrained by facility intakes, standardized to equivalent numbers of 1-year-old fish. A conversion rate between all life history stages and age 1 is calculated using species-specific survival tables based on life history schedule and age-specific mortality rates. An individual younger than age 1 is a fraction of an age-one equivalent; an individual older than age 1 represents more than one age-one equivalent. EPA finds it appropriate to use the A1E measure because information in the record indicates that an overwhelming majority of eggs, larvae and juveniles do not survive into adulthood and the A1E calculations adjust for differences in survivorship based on species and age-specific mortality rates. EPA recognizes that using A1Es simplifies a complex ecological situation, because some of the smaller fish would provide an ecological benefit to other species as food even if they would not survive to adulthood. Recognizing this as one nonmonetized benefit in the analysis, using an A1E approach is the most reasonable approach available because to date, there is insufficient data to account for the extent to which organisms that do not survive to adulthood provide a benefit to other organisms which can be reliably monetized.
- Forgone fishery yield—pounds of commercial fish harvest and numbers of recreational fish and shellfish that are not harvested because of impingement mortality and entrainment. EPA used the Thompson-Bell equilibrium yield model [145] to convert impingement mortality and entrainment to forgone fishery yield, assuming that (1) impingement mortality and entrainment reduces the future yield of harvested adults, and (2) reductions in impingement mortality and entrainment rates will lead to an increase in harvested biomass. The general procedure involves multiplying age-specific harvest rates by age-specific weights to calculate an age-specific expected yield.
- Biomass production forgone—biomass that would have been produced had individuals not been impinged or entrained,[146] calculated for all species from species- and age-specific growth rates and survival probabilities. It refers to the mass of impinged and entrained organisms that would have served as valuable components of aquatic food webs, particularly as an important food supply to other aquatic species.

Estimates of forgone fishery yield include direct and indirect losses of impinged and entrained species that are harvested. Indirect losses represent the yield of harvested species lost because of reductions in prey availability according to a simple trophic transfer model (i.e., forage species).[147] Chapter 3 of the BA contains detailed methodology for these analyses.

Studies from individual facilities may underestimate or overestimate impingement mortality and entrainment rates at those facilities. For example, facility studies typically focus on a subset of fish species affected by impingement mortality and entrainment, resulting in other species being ignored. The number of individuals lost to impingement mortality and entrainment is then underestimated. Estimating the magnitude of this underestimate is not possible because of the low number of replicate studies. Moreover, studies often do not count early life stages of organisms that are more difficult to identify. In addition, many of the impingement mortality and entrainment studies used by the Agency were conducted more than 30 years ago, prior to the improvement of aquatic conditions that have resulted from implementation of the CWA as well as State and local laws and efforts. In locations where water quality was degraded at the time of impingement mortality and entrainment sampling relative to current conditions, the abundance and diversity of fish populations might have been depressed, resulting in low impingement mortality and entrainment estimates. Therefore, use of these data may underestimate the magnitude of current impingement mortality and entrainment. Alternatively, studies could have been conducted in locations where local fish populations are now lower than they were when the study occurred. Such a shift in fish populations might have occurred because of natural variability in populations, because of other anthropogenic effects (i.e., over-harvesting), or because of competition from invasive species. In such cases, the use of these data may overestimate the magnitude of current impingement mortality and entrainment.

EPA's use of linear methods for projecting losses to fish and shellfish in the waterbody may also overstate or understate impacts. Nevertheless, the data from facility studies are the best means to estimate the relative magnitude of impingement mortality and entrainment nationwide. Exhibit X–2 presents EPA's estimates of baseline annual impingement mortality and entrainment, and reductions in annual impingement mortality and entrainment estimated to occur under the final rule and other options considered. Impingement mortality and entrainment reductions under the final rule are less than the reductions under Proposal Option 2 and greater than reductions under Proposal Option 4. Unlike the analysis of Proposal Option 2, EPA did not model the entrainment reductions from cooling tower installation under the final rule and Proposal Option 4 because these would be based on site-specific determinations of BTA, which are not possible to predict with information EPA has today. EPA estimated a small amount of entrainment losses under the final rule and Proposal Option 4 due to the assumed installation of variable speed pumps at some facilities to achieve compliance via the low velocity compliance alternative.

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[145] Ricker, W.E. 1975. Computation and interpretation of biological statistics of fish populations. Fisheries Research Board of Canada, Bulletin 191.

[146] Rago, P.J. 1984. Production forgone: An alternative method for assessing the consequences of fish entrainment and impingement losses at power plants and other water intakes. Ecological Modeling, 24(1–2): 79–111.

[147] Indirect losses account for about 10 percent of commercial and recreational harvest reductions at baseline.

EXHIBIT X–2—BASELINE ANNUAL IM&E AND ANNUAL REDUCTIONS IN IM&E FOR EXISTING UNITS AT ALL FACILITIES SUBJECT TO THE FINAL RULE

Loss mode [a]	Reduction in annual IM&E by regulatory option [b c]			Baseline annual IM&E
	Proposal option 4	Final rule—existing units	Proposal option 2	
Individuals (millions)				
IM	419.9	441.3	511.9	568.6
E	399.8	1,693.9	335,447.6	497,316.3
IM&E	819.7	2,135.2	335,959.4	497,884.8
Age-One Equivalents (millions)				
IM	612.8	647.5	748.2	824.2
E	1.4	4.5	889.3	1,106.7
IM&E	614.2	652.0	1,637.5	1,931.0
Forgone Fishery Yield (million lbs)				
IM	12.6	13.3	15.4	16.9
E	0.0	0.1	35.7	52.9
IM&E	12.6	13.4	51.1	69.8
Production Forgone (million lbs)				
IM	129.7	136.5	157.2	174.8
E	0.5	2.4	337.0	451.8
IM&E	130.3	138.9	494.2	626.6

[a] IM = impingement mortality; E = entrainment; IM&E = impingement mortality and entrainment.
[b] IM&E Effects by Option: Proposal Option 4 = impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 50 mgd; Final Rule = impingement mortality standards based on modified traveling screens for all facilities with flow greater than 2 mgd; Proposal Option 2 = intake flow commensurate with closed-cycle cooling for facilities that have a DIF of greater than 125 mgd and impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 2 mgd.
[c] The totals presented here do not include IM&E reductions associated with new units. Estimated IM&E reductions associated with the new unit provision of the final rule are presented in Exhibit X–4.

Exhibit X–3 presents EPA's estimates of annual impingement mortality and entrainment for final rule and other considered options by category of fish species. Estimates of annual forgone fishery yield include both direct losses of harvested species and indirect losses from reductions in prey fish species. Organisms convert (on average) only about 10 percent of the mass of food they consume into additional tissue mass. Thus, although essential to maintain ecosystem function, the vast majority of biomass moving through food webs does not reach higher trophic levels associated with commercial and recreational species and harvest. Instead, the biomass of prey species is metabolized and used for predator locomotion, reproduction, and tissue repair. Accordingly, the portion of impingement mortality and entrainment that are counted within the forgone harvest metric represent only a small percentage of all organisms experiencing impingement mortality and entrainment at cooling water intake structures. Neither forage species nor the unlanded portion of recreational and commercial species were assigned direct use values in this analysis, although losses in forage species did contribute to the overall losses in recreational and commercial species as noted above. Because the majority of annual impingement mortality and entrainment include unharvested recreational and commercial fish and forage fish, considering nonuse values in the final rule benefits analysis is particularly important. If nonuse values were not considered at all, only two to three percent of fish losses would be represented in monetized benefits.

EXHIBIT X–3—DISTRIBUTION OF ANNUAL BASELINE IM&E AND REDUCTIONS IN IM&E BY SPECIES CATEGORY, FOR INDIVIDUAL ORGANISMS AND AGE-1 EQUIVALENTS, AT EXISTING UNITS FOR THE FINAL RULE AND OPTIONS CONSIDERED

IM&E Metric [a]	Reduction in IM&E by regulatory option [b c]			Baseline IM&E
	Proposal option 4	Final rule—existing units	Proposal option 2	
Individuals (millions)				
All Species	819.7	2,135.2	335,959.4	497,884.8
Forage Species	607.9	1,423.6	224,323.1	325,069.1
Commercial & Recreational Species	211.8	711.5	111,636.3	172,815.8
Commercial & Recreational Harvest (millions of fish)	16.1	17.1	44.7	54.0
Lost Individuals with Direct Use Value (%)	1.97%	0.80%	0.01%	0.01%
Age-One Equivalents (millions)				
All Species	614.2	652.0	1,637.5	1,931.0

EXHIBIT X–3—DISTRIBUTION OF ANNUAL BASELINE IM&E AND REDUCTIONS IN IM&E BY SPECIES CATEGORY, FOR INDIVIDUAL ORGANISMS AND AGE-1 EQUIVALENTS, AT EXISTING UNITS FOR THE FINAL RULE AND OPTIONS CONSIDERED—Continued

IM&E Metric [a]	Reduction in IM&E by regulatory option [b c]			Baseline IM&E
	Proposal option 4	Final rule—existing units	Proposal option 2	
Forage Species	528.2	560.8	1,258.7	1,459.7
Commercial & Recreational Species	85.9	91.2	378.8	471.3
Commercial & Recreational Harvest (millions of fish)	16.1	17.1	44.7	54.0
A1E Losses with Direct Use Value (%)	2.63%	2.62%	2.73%	2.80%

[a] IM&E = impingement and entrainment; A1E= age-one equivalent;
[b] IM&E Effects by Option: Proposal Option 2 = impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 50 mgd; Final Rule = impingement mortality standards based on modified traveling screens for all facilities with flow greater than 2 mgd; Proposal Option 2 = intake flow commensurate with closed-cycle cooling for facilities that have a DIF of greater than 125 mgd and impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 2 mgd.
[c] The totals presented here do not include IM&E reductions associated with new units. Estimated IM&E reductions associated with the new unit provision of the final rule are presented in Exhibit X–4.

In addition to the final rule and other options analyzed for existing units (Proposal Option 4 and Proposal Option 2), EPA analyzed requirements for new units at existing facilities. EPA's new unit provision in the final rule establishes entrainment requirements for all new stand-alone units at existing facilities. EPA could not directly apply the extrapolation methodology used for existing units because facility-specific information was not available for new units. Instead, EPA estimated impingement mortality and entrainment reductions on the basis of impingement mortality and entrainment reductions per million gallons per day from the analysis of existing units. The estimated reduction in impingement mortality and entrainment for the new unit requirement is summarized in Exhibit X–4.

EXHIBIT X–4—ANNUAL REDUCTIONS IN IM&E BY SPECIES CATEGORY FOR THE FINAL RULE FOR NEW UNITS

IM&E metric [a]	Reduction in IM&E [b]
Individuals (millions)	
All Species	867.2
Forage Species	566.1
Commercial and Recreational Species	301.1
Commercial and Recreational Harvest (millions of fish)	0.1
Lost Individuals with Direct Use Value (%)	0.01%
Age-One Equivalents (millions)	
All Species	2.3
Forage Species	1.7
Commercial and Recreational Species	0.7
Commercial and Recreational Harvest (millions of fish)	0.1
A1E Losses with Direct Use Value (%)	2.87%

[a] A1E = age-one equivalent; IM&E = impingement mortality and entrainment.
[b] Impingement mortality and entrainment reductions increase throughout the compliance period. The values presented here reflect the peak reductions achieved in 2059, the final year of the compliance period.
IM&E Effects: Entrainment requirements for all stand-alone or units.

D. National Benefits of the Final Rule and Options Considered

1. Overview

Economic benefits of the final rule and other options considered for regulated facilities can be categorized broadly into use and nonuse benefits of goods and services. Use values include benefits that pertain to the human use (direct or indirect) of affected fishery resources. Use values reflect the value of all current direct and indirect uses of a good or service. Direct use benefits can be further categorized according to whether affected goods and services are traded in the market (i.e. commercially captured fish are traded, recreational catch is not). Likewise, indirect use benefits can be linked to direct goods and services. For example, reductions in impingement mortality and entrainment of forage fish will enhance the biomass of species targeted for commercial (market) and recreational (nonmarket) uses. It could also affect property values.

Nonuse benefits are those benefits that are independent of any current or anticipated human use of a resource. Nonuse benefits reflect human values associated with existence and bequest motives. In other words, these values reflect the value the public places on something simply as a result of its existence or natural functioning. EPA estimated the economic benefits from national regulatory options using a range of valuation methods. Commercial fishery benefits were valued using market data. Recreational angling benefits were valued using a benefits transfer approach based on revealed and stated preference data. To estimate indirect use benefits from reduced impingement mortality and entrainment of forage species, EPA used a simple trophic transfer model. This model translated changes in impingement mortality and entrainment of forage fish into changes in the harvest of commercial and recreational species. All benefits for fish saved under today's final rule are estimates on the basis of projected numbers of age-one equivalent fish, converted to harvestable age equivalents on a species-by-species basis for those commercial species analyzed.

EPA calculated the monetary value of use benefits of the final rule and other options considered for existing facilities using two discount rate values: 3 and 7 percent. All dollar values presented are in 2011 dollars. Because avoided fish deaths occur mainly in fish that are younger than harvestable age (eggs, larvae, and juveniles), the main benefits from avoided impingement mortality and entrainment would be realized typically 3 to 4 years after their avoided death. A detailed description of the approaches used to address this is in Appendix C of the BA.

Neither forage species nor the unlanded portion of recreational and commercial species were assigned direct use values in this analysis. Their potential value to the public is derived from several alternative sources: Their indirect use as both food and breeding population for those fish that are harvested; and nonuse value. The nonuse value includes individuals' WTP (willingness to pay) for the protection of fish based on a sense of altruism, stewardship, bequest, or vicarious consumption; and their support of ecosystem stability and function. To estimate a subset of nonuse benefits from reducing impingement mortality and entrainment of forage species and unlanded commercial and recreational species, EPA conducted a benefits transfer using a nonmarket valuation study of aquatic ecosystem improvements. This effort generated partial estimates of nonuse values for resource changes for a species that represents less than one percent of adverse environmental impacts.

EPA developed and fielded an original stated preference survey to estimate total WTP for improvements to fishery resources affected by impingement mortality and entrainment from regulated 316(b) facilities (75 FR 42438, July 21, 2010). Preliminary results of the stated preference survey were described in a Notice of Data Availability (77 FR 34927, June 12, 2012). EPA presents preliminary benefits estimates based on the stated preference survey in the BA to demonstrate progress on this effort. In the absence of final survey results, EPA estimated partial nonuse benefits for the final rule using the benefits transfer approach from proposal. EPA updated the proposal results to incorporate additional stock assessment data for winter flounder, the species used as the basis for the analysis. Due to the challenges associated with estimating nonuse benefits, some nonuse benefits are described only qualitatively.

2. Timing of Benefits

Discounting refers to the economic conversion of future benefits and costs to their present values, accounting for the fact that individuals value future outcomes less than comparable near-term outcomes. Discounting enables a valid comparison of benefits and costs that occur across different periods. EPA used discounting to account for differences in the timing across benefits and costs under the final rule and options considered. EPA estimated the expected benefits of the final rule once the rule takes full effect, then used discounting to account for delays in the realization of benefits. Two different delays affect the timing of benefits under the final rule and options considered.

First, facilities will begin to incur costs prior to technology installation. Facilities will face regulatory requirements once the rule is effective, but it will take time for requirements to be developed and for the required technology to be installed. Analyzed facilities are assigned a technology installation year which considers facility characteristics and technology being installed. EPA assumed that facilities installing impingement technology tend to complete technology installation sooner than facilities installing closed-cycle cooling (for other options considered). The assignment of technology installation years is speculative on EPA's part, because EPA does not have sufficient data on hand to project the schedules that Directors will set for facilities. See Chapter 3 of the EA document for the final existing facilities rule for details on EPA's development of technology installation years. EPA effectively discounts benefits to a greater extent than costs to account for the lag between the incurrence of costs and the realization of benefits.

Second, an additional time lag will result between technology implementation and use values via increased fishery yields. This lag occurs because several years could pass between the time an organism is spared from impingement mortality or entrainment and the time of its potential harvest. For example, a larval fish spared from entrainment (in effect, at age 0) could be caught by a recreational angler at age 3, meaning that a 3-year time lag arises between the incurred technology cost and the realization of the estimated recreational benefit. Likewise, if a 1-year-old fish is spared from impingement and is then harvested by a commercial waterman at age 2, there is a 1-year lag between the incurred cost and the subsequent commercial fishery benefit. To account for this growth period, EPA applied discounting by species groups in each regional study. Note that nonuse values (depending on how they are measured) do not necessarily need to be discounted similarly.

3. Recreational Fishing Valuation

a. Recreational Fishery Methods

To estimate recreational benefits of the final options, EPA developed a benefits transfer approach on the basis of a meta-analysis of recreational fishing valuation studies designed to measure the various factors that determine WTP for catching an additional fish per trip. Regional benefits are summarized as follows (for details, see Chapter 7 of the BA):

1. Estimate the annual forgone catch of recreational fish (number of fish) attributable to impingement mortality and entrainment under current conditions.
2. Estimate the marginal value per fish using a benefit transfer function based on a meta-analysis of recreational fishing studies.
3. Multiply the forgone catch by the marginal value per fish to estimate the total annual value of the forgone catch.
4. Estimate the annual value of reductions in the forgone catch attributable to the regulatory analysis options.
5. Discount the time path of benefits at 3 and 7 percent to reflect the time lag between impingement mortality and entrainment reductions and increased harvests.

b. Estimated Benefits to Recreational Anglers

Decreasing impingement mortality and entrainment increases the number of fish available to be caught by recreational anglers, thereby increasing angler welfare. Exhibit X–5 shows the estimated benefits resulting from reduced impingement mortality and entrainment under today's final existing facilities rule and other options that EPA considered. The total annualized recreational fishing benefits for all regions at existing units of existing facilities for the final rule (impingement mortality and entrainment combined) are $18 million using a 3 percent discount rate and $14 million using a 7 percent discount rate. Annual recreational fishing benefits for other options considered range from $17 to $43 million using a 3 percent discount rate and $13 million to $30 million using a 7 percent discount rate.

EXHIBIT X–5—ANNUAL RECREATIONAL FISHING BENEFITS FROM ELIMINATING OR REDUCING IM&E AT EXISTING UNITS AT EXISTING FACILITIES FOR THE FINAL RULE AND OTHER OPTIONS CONSIDERED

Regulatory option [a]	Increased harvest (million fish)	3% discount rate (million 2011$)	7% discount rate (million 2011$)
Proposal Option 4	6.1	17.1	12.6
Final Rule—Existing Units	6.5	18.2	13.5
Proposal Option 2	20.5	43.0	29.5
Baseline	25.3	78.8	72.0

[a] IM&E Effects by Option: Proposal Option 4 = impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 50 mgd; Final Rule = impingement mortality standards based on modified traveling screens for all facilities with flow greater than 2 mgd; Proposal Option 2 = intake flow commensurate with closed-cycle cooling for facilities that have a DIF of greater than 125 mgd and impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 2 mgd.

4. Commercial Fishing Valuation

Reductions in impingement mortality and entrainment at cooling water intake structures are expected to benefit the commercial fishing industry. By reducing the number of fish killed, the number of fish available for harvest is expected to increase. The next section summarizes the methods EPA used to estimate benefits to the commercial fishing sector. The section after that presents the estimated value of commercial fishing benefits.

a. Commercial Fishing Valuation Methods

The total loss to the economy from impingement mortality and entrainment impacts on commercially harvested fish species is determined by the sum of changes in both producer and consumer surplus. EPA assumed a linear relationship between stock and harvest, such that if 10 percent of the current commercially targeted stock were harvested, 10 percent of the commercially targeted fish lost to impingement mortality and entrainment would have been harvested absent impingement mortality and entrainment. The percentage of fish harvested is based on data of historical fishing mortality rates.

Producer surplus provides an estimate of the economic damages to commercial fishers, but welfare changes can also be expected to accrue to final consumers of fish and to commercial consumers (including processors, wholesalers, retailers, and middlemen) if the projected increase in harvest is accompanied by a change in price. The analysis of market impacts involves the following steps (for details, see Chapter 6 of the BA):

1. Assessing the net welfare changes for fish consumers due to changes in fish harvest and the corresponding change in fish price.
2. Assessing net welfare changes for fish harvesters due to the change in total revenue, which could be positive or negative.
3. Calculating the increase in net social benefits when the fish harvest changes by combining the welfare changes for consumers and harvesters.

For a more detailed description of the methodology for commercial fishing, see Chapter 6 of the BA.

b. Commercial Fishing Valuation Results

Exhibit X–6 presents the estimated annual commercial fishing benefits attributable to the proposed options. The results reported include the total reduction in losses in pounds of fish, and the value of this reduction discounted at 3 and 7 percent. Total estimated annualized commercial fishing benefits for the United States for the final rule are $0.9 million using a 3 percent discount rate and $0.7 million using a 7 percent discount rate. Annual commercial fishing benefits for other options considered range from $0.9 million to $3.9 million using a 3 percent discount rate and $0.7 million to $2.7 million using a 7 percent discount rate. EPA estimated the expected price changes from eliminating baseline levels of impingement mortality and entrainment and found them to be small, ranging from 0.2 to 2.5 percent.

EXHIBIT X–6—ANNUAL COMMERCIAL FISHING BENEFITS FROM ELIMINATING OR REDUCING IM&E AT EXISTING UNITS AT EXISTING FACILITIES FOR THE FINAL RULE AND OTHER OPTIONS CONSIDERED

Regulatory option [a]	Increased harvest (million lbs)	3% discount rate (million 2011$)	7% discount rate (million 2011$)
Proposal Option 4	5.3	0.9	0.7
Final Rule—Existing Units	5.7	0.9	0.7
Proposal Option 2	14.0	3.9	2.7
Baseline	17.3	8.0	7.2

[a] IM&E Effects by Option: Proposal Option 4 = impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 50 mgd; Final Rule = impingement mortality standards based on modified traveling screens for all facilities with flow greater than 2 mgd; Proposal Option 2 = intake flow commensurate with closed-cycle cooling for facilities that have a DIF of greater than 125 mgd and impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 2 mgd.

5. Nonuse Benefits

Aquatic organisms with no direct use benefits account for the majority of cooling water intake structure losses (Exhibit X–3). Although many individuals may not use a particular waterbody for recreation or fishing, individuals nevertheless may value improvements in that waterbody. To quantitatively assess the ecological gains from the final rule and other options considered, EPA took both of the only two approaches available for quantifying nonuse benefits—a benefits transfer approach and a stated preference survey. It is not necessary to use a stated preference survey approach to calculate benefits; however, important nonuse benefits can be missed by not using a stated preference survey approach. So EPA took both approaches, but relied on only the benefits transfer approach for the benefits analysis supporting the final rule. The benefits transfer approach relies on the existence of previously published studies with values that can be transferred; in instances where nonuse is potentially significant, as is the case here, previously published studies would only include nonuse value if they adopted a stated preference approach.

EPA used a benefit transfer approach to partially monetize nonuse benefits associated with reductions in impingement mortality and entrainment of fish, shellfish, and other aquatic organisms under the regulatory options for the North Atlantic and Mid-Atlantic benefits regions. EPA applied estimated values from a study conducted in Rhode Island; these estimates are likely to be more representative of nonuse values held by individuals residing in the Northeast United States and less accurate in other regions. EPA was unable to identify comparable studies conducted in other regions that could be used to estimate nonuse values. Chapter 8 of the BA provides further detail on this analysis.

The preferred techniques used to estimate total values (including both use and nonuse values), in general, are benefits transfer or to conduct a stated preference survey. There are many studies in the environmental economics literature that quantify benefits or WTP associated with various types of water quality and aquatic habitat changes. However, none of these studies allows the isolation of non-market WTP associated with quantified reductions in impingement mortality and entrainment for forage fish or unlanded portion of commercial and recreational species.

a. Nonuse Benefits Transfer

EPA identified a recent stated preference survey of Rhode Island residents that is closely related to the 316(b) policy context. The study results have been published in multiple scientific journals and books including Johnston et al.[148] and Zhao et al.[149] Both the Rhode Island study and the present context address policy changes that increase the number of forage fish in aquatic habitat with unknown effects on overall fish populations. The Rhode Island study was developed originally as a case study addressing Rhode Island residents' preferences for the restoration of migratory fish passage over dams in Rhode Island's Pawtuxet and Wood-Pawcatuck watersheds. It estimates nonuse values by asking respondents to consider changes in ecological indicators reflecting quantity of habitat, abundance of wildlife, ecological condition, and abundance of migratory fish species. Within this study, estimated values were based on the relative change in abundance of fish species most affected by restoration.

Estimating benefit functions from the Rhode Island choice experiment survey [150] allows one to distinguish benefits associated with resource uses from those associated primarily with nonuse motives. Within the benefit transfer application, WTP is quantified for increases in non-harvested fish alone on the basis of the implicit price for migratory fish changes. This transfer holds constant all effects related to identifiable human uses (e.g., effects on catchable fish, public access, and observable wildlife). The remaining welfare effect—derived purely from effects on forage fish with little or no direct human use—may therefore be most accurately characterized as a nonuse benefit realized by households.

The estimation of nonuse values involved the following steps:

1. Use a model published by Zhao et al.[151] to estimate household WTP per percent increase in the number of fish in a given watershed. The household WTP values reflect a survey version that characterizes effects on the number of migratory fish passing upstream.

2. Calculate the relative change in abundance for the fish species most affected by the regulation. The structure of the transfer study dictates that WTP should be evaluated based on the single species that would experience the greatest relative increase in abundance from restoration and that WTP estimates from multiple species impacted by IM&E should not be treated as strictly additive. After reviewing available stock assessment data, current stock size, and the magnitude of IM&E, EPA determined winter flounder to be the species likely to experience the greatest percent increase in abundance among those species with sufficient stock information to conduct the analysis within the boundaries of the North Atlantic and Mid-Atlantic benefits regions. This species is harvested; however, early life stages of recreational and commercial species may be eaten by other organisms and therefore have nonuse values.

3. Estimate total household WTP by applying model results for WTP per percentage of estimated winter flounder impingement mortality and entrainment. Total regional WTP is the product of household WTP and the number of households in the affected region (for details, see Chapter 8 of the BA).

b. Estimated Nonuse Benefits for the North Atlantic and Mid-Atlantic Regions

EPA expects that a decrease in impingement mortality and entrainment will lead to increased fish abundance in affected water bodies, thus increasing nonuse benefits. Exhibit X–7 shows the benefits that would result from reducing impingement mortality and entrainment through today's final rule and other options considered. Application of the transfer study requires that the increases be expressed as a percent improvement relative to a maximum number of fish that could be supported. EPA calculated estimates of WTP on the basis of the increase in age-1 equivalent winter flounder relative to the estimated number of age-1 fish when the stock is at maximum sustainable yield, thus assuming that the population structure of the current stock is similar to the larger stock. The total annualized nonuse benefits for the North Atlantic and Mid-Atlantic regions for the existing unit provision of the final rule are $1 million using a 3 percent discount rate and $0.8 million using a 7 percent discount rate. For other options considered, annualized nonuse benefits range from $0.3 to $51 million using a 3 percent discount rate and $0.3 to $37 million using a 7 percent discount rate.

[148] Johnston, R.J., E.T. Schultz, E.T., K. Segerson, E.Y. Besedin, and M. Ramachandran. 2012. Enhancing the content validity of stated preference valuation: The structure and function of ecological indicators. Land Economics, 1: 102–120.

[149] Zhao, M., Johnson, R.J. and Schultz, E.T. 2013. What to Value and How? Ecological Indicator Choices in Stated Preference Valuation. Environmental Resource Economics. Published online, February 8, 2013.

[150] Johnston, R.J., E.T. Schultz, E.T., K. Segerson, E.Y. Besedin, and M. Ramachandran. 2012. Enhancing the content validity of stated preference valuation: The structure and function of ecological indicators. Land Economics, 1: 102–120; Zhao, M., Johnson, R.J. and Schultz, E.T. 2013. What to Value and How? Ecological Indicator Choices in Stated Preference Valuation. Environmental Resource Economics. Published online, February 8, 2013.

[151] Op cit.

EXHIBIT X–7—ANNUAL NONUSE BENEFITS FROM ELIMINATING OR REDUCING IM&E AT EXISTING UNITS AT EXISTING FACILITIES IN THE NORTH ATLANTIC AND MID-ATLANTIC REGIONS FOR THE FINAL RULE AND OPTIONS CONSIDERED [a]

Regulatory option [b]	Winter flounder IM&E (million A1E)	Increased winter flounder A1E abundance (%)	3% discount rate (millions 2011$)	7% discount rate (millions 2011$)
Proposal Option 4	0.03	0.02	0.3	0.3
Final Rule—Existing Units	0.08	0.07	1.0	0.8
Proposal Option 2	4.78	4.18	51.1	37.3
Baseline	6.23	5.44	99.1	96.9

[a] IM&E = impingement and entrainment; A1E = age-one equivalent.
[b] IM&E Effects by Option: Proposal Option 4 = impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 50 mgd; Final Rule = impingement mortality standards based on modified traveling screens for all facilities with flow greater than 2 mgd; Proposal Option 2 = intake flow commensurate with closed-cycle cooling for facilities that have a DIF of greater than 125 mgd and impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 2 mgd.

c. Stated Preference Survey

EPA conducted a stated preference survey to calculate benefits associated with minimizing adverse impacts to aquatic ecosystems from cooling water intakes. Refer to Sections VI.F.1 and X.D.1 for additional discussion of the stated preference survey. EPA did not rely on the results of its stated preference survey in estimating the benefits of today's rule.

6. Threatened and Endangered Species

This section summarizes methods and results of EPA's analysis of benefits from improved protection of T&E species from today's final rule and options considered. Chapter 5 of the BA provides further detail on this analysis.

Even if levels of mortality due to impingement and entrainment from cooling water intake structures of T&E species are low in absolute numbers, they may represent a substantial portion of annual reproduction because of the reduced population levels that cause a species to be protected. Consequently, impingement mortality and entrainment may either lengthen recovery time, or hasten the demise of these species. Adverse effects of cooling water intake structures on T&E species can occur in several ways:

- Populations of T&E species may suffer direct harm as a consequence of impingement mortality and entrainment.
- T&E species may suffer indirect harm if a cooling water intake structure alters food webs.
- Cooling water intake structures can alter habitat designated as critical to the long-term survival of T&E species.

Consequently, the 316(b) regulation will help preserve threatened and endangered species.

a. Qualitative Assessment of Impingement Mortality and Entrainment Impacts on T&E Species

By definition, T&E species are characterized by low population levels. As such, it is unlikely that these species are recorded in significant number, if recorded at all, in impingement mortality and entrainment monitoring studies. Thus, losses are difficult to identify and quantify in a framework developed for non-listed species. Consequently, EPA developed a qualitative methodology to estimate the number of T&E species affected by impingement mortality and entrainment.

To qualitatively assess the potential for cooling water intake structure impacts on aquatic T&E species, EPA constructed a database that assessed the geographical overlap of cooling water intake structure and habitat used by aquatic T&E species. This database identified the number of T&E species potentially affected by each regulated 316(b) facility, and the number of facilities potentially affecting each T&E species. Additional details are in Chapter 5 of the BA.

Using this database, EPA found 99 Federally-listed aquatic T&E species that overlap with at least one covered cooling water intake structure (an interaction in Exhibit X–8). T&E species included freshwater, marine, and anadromous fish, freshwater mussels, and sea turtles. On average, the habitat of each T&E species overlapped with 22 covered facilities (Exhibit X–8), suggesting that the 316(b) rule may have substantial positive benefits of ensuring the long-term sustainability and recovery of T&E species.

EXHIBIT X–8—NUMBER OF REGULATED 316(B) COOLING WATER INTAKE STRUCTURES IN AQUATIC T&E SPECIES HABITAT ON A PER-SPECIES BASIS

Subset of affected species [a b]	Species	Interactions [b]	Facilities per T&E species [c]	
			Avg	Max
All T&E Species	99	2,158	21.8	103
T&E Freshwater Mussels	53	1,176	21.8	103
T&E Anadromous Fish	12	235	19.6	101
T&E Freshwater Fish	21	65	3.1	7
T&E Snails	7	199	28.4	49
Sea Turtles	6	483	80.5	102

[a] Aquatic T&E species includes species listed as threatened or endangered by the U.S. Fish and Wildlife Service (freshwater) or National Oceanic and Atmospheric Administration National Marine Fisheries Service (marine). Only aquatic species overlapping with a minimum of one cooling water intake structure are included.
[b] Each interaction represents an overlap between the range of a T&E species and cooling water intake structure.
[c] Avg = average, Max = maximum.

b. Quantitative Assessment of Impingement Mortality and Entrainment Impacts on T&E Species

Although difficult to observe and quantify, EPA identified 14 T&E species with confirmed impingement mortality and entrainment based on facility impingement mortality and entrainment studies. EPA notes that some impingement mortality and entrainment studies identifying T&E losses were conducted prior to the listing of the species under the ESA. In addition to documented species-level instances of T&E mortality, EPA identified impingement mortality and entrainment at the level of genera [152] when these genera contain a T&E species whose habitat range overlapped the reporting facility's cooling water intake structure. Although these are not confirmed impingement mortality and entrainment of T&E species, they provide evidence that additional T&E species are likely to be directly affected by impingement mortality and entrainment. EPA found seven genus-level matches, suggesting that the 14 T&E species suffering impingement mortality and entrainment may be inaccurate.

Of the 14 Federally-listed T&E species for which EPA was able to document losses in impingement mortality and entrainment studies, EPA was able to quantify impingement mortality and entrainment for two species (pallid sturgeon and Topeka shiner). The documented impingement mortality and entrainment occurred before these species were Federally-listed. Data were either qualitative or of insufficient quality to quantify local or regional impingement mortality and entrainment for the remaining 12 Federally-listed T&E species. EPA also quantified impingement mortality and entrainment for the American paddlefish (*Polyodon spathula*), listed by several states as threatened or endangered under State law, using facility impingement mortality and entrainment studies. Exhibit X–9 presents EPA's estimates of baseline annual impingement mortality and entrainment, and reductions in impingement mortality and entrainment which EPA estimates will occur under the final rule and other options considered.

EXHIBIT X–9—BASELINE ANNUAL IM&E FOR T&E SPECIES AND REDUCTIONS FOR EXISTING UNITS AT EXISTING FACILITIES (A1ES) [a b]

Species	Proposal option 4	Final rule—existing units	Proposal option 2	Baseline
Paddlefish [c]	7,930.1	8,245.4	15,659.7	18,841.4
Pallid Sturgeon	65.4	67.6	78.0	89.5
Topeka Shiner	2,910.9	3,009.8	3,471.9	3,984.9
Total	10,906.4	11,322.8	19,209.5	22,915.7

[a] IM&E = impingement and entrainment; A1E = age-one equivalent.
[b] IM&E Effects by Option: Proposal Option 2 = impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 50 mgd; Final Rule = impingement mortality standards based on modified traveling screens for all facilities with flow greater than 2 mgd; Proposal Option 2 = intake flow commensurate with closed-cycle cooling for facilities that have a DIF of greater than 125 mgd and impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 2 mgd.
[c] The American paddlefish is not a Federally-listed T&E species but is listed as threatened or endangered on several state lists.
[d] This analysis is based solely on IM controls.

Impingement mortality and entrainment is only one of many factors that adversely affect T&E species. Estimating total population impacts from changes in impingement mortality and entrainment requires estimates of current populations of these fish and estimates of other anthropogenic effects which were not readily available for all T&E species with quantified impingement mortality and entrainment at the time of this analysis. Therefore, EPA was unable to quantify effects on T&E populations from the 316(b) regulation.

c. Valuation Methods of T&E Fish Species

EPA had sufficient data from impingement mortality and entrainment studies to quantify impingement mortality and entrainment estimates for three T&E species, Topeka shiner, pallid sturgeon, and paddlefish (Exhibit X–9). Two of these species (pallid sturgeon and paddlefish) have potential use values. A limited recreational fishery (mostly catch and release) exists for paddlefish in several states; although harvesting pallid sturgeon is illegal, the species is sometimes caught by recreational anglers. EPA estimated recreational use values for pallid sturgeon and paddlefish by applying transfer values from a Random Utility Model analysis it conducted to evaluate recreational fishing benefits of the 316(b) Phase II regulation to quantified impingement mortality and entrainment (for details, see Chapter 5 of the BA).

EPA was unable to generate estimates of nonuse values for T&E fish species because reliable population estimates needed to transfer the values were unavailable. However, EPA emphasizes that nonuse values for T&E fish species are likely to be significantly greater than any use values. Harvest of these species is prohibited, reflecting a societal judgment that protection and preservation of these species is of greater value than harvest.

d. Estimated Monetary Benefits From Reduced Mortality of T&E Fish Species

Exhibit X–10 presents the estimated annualized benefits for a subset of T&E species. For existing units under the final rule, EPA estimates total annualized use benefits for T&E species with quantified impingement mortality and entrainment of $0.4 million using a 3 percent discount rate and $0.3 million using a 7 percent discount rate. For other options considered, annualized benefits range from $0.4 to $0.7 million using a 3 percent discount rate and $0.3 to $0.5 million using a 7 percent discount rate.

[152] Genera is the plural of genus. Genus is the rank superior to species in taxonomic biological classification. For example, the genus of Atlantic salmon (*Salmo falar*) is *Salmo.*

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EXHIBIT X–10—ANNUAL USE BENEFITS FROM ELIMINATING OR REDUCING IM&E OF T&E SPECIES AT EXISTING UNITS OF EXISTING FACILITIES FOR THE FINAL RULE AND OTHER OPTIONS CONSIDERED [a b c]

Regulatory option	Increased harvest (number of fish)	3% discount rate (million 2011$)	7% discount rate (million 2011$)
Proposal Option 4	7,995.5	0.4	0.3
Final Rule—Existing Units	8,313.0	0.4	0.3
Proposal Option 2	15,737.7	0.7	0.5
Baseline	18,930.9	1.2	1.3

[a] IM&E = impingement and entrainment; T&E = threatened and endangered. Values are included for pallid sturgeon and paddlefish in the Inland region.
[b] IM&E Effects by Option: Proposal Option 4 = impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 50 mgd; Final Rule = impingement mortality standards based on modified traveling screens for all facilities with flow greater than 2 mgd; Proposal Option 2 = intake flow commensurate with closed-cycle cooling for facilities that have a DIF of greater than 125 mgd and impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 2 mgd.
[c] This analysis is based solely on impingement mortality controls.

EPA notes that the benefit values presented in Exhibit X–10 represent only a fraction of values for T&E species potentially affected by the final existing facilities rule. The Agency was able to obtain only use values and for only a small subset of all affected T&E species. Moreover, because of the nature of T&E species, even a small increase in population could yield economic and ecological benefits (e.g., Richardson and Loomis; [153] Bell et al.; [154] Berrens et al.[155])

e. Valuation Methods for T&E Sea Turtles

In addition to estimating values of T&E fish with quantitative estimates of impingement mortality and entrainment, EPA estimated the WTP for sea turtle conservation. In this analysis, EPA applied estimates from a study using a stated preference valuation approach to estimate total economic value of a management program that reduces the risk of extinction of loggerhead sea turtles.[156]

Although impingement mortality and entrainment of turtles is relatively low compared to mortality from shrimp trawling and other fisheries,[157] it is known that reducing turtle mortality during juvenile and subadult life stages can have a substantial positive effect on population growth.[158] The marginal change in extinction probability of sea turtles due to 316(b) regulatory options is likely to be at least 0.01, or a 1 percent decrease in the probability of extinction over 25 years. This assessment is based on reports that impingement mortality and entrainment may result in the loss of more than 100 turtles per year and because turtle population growth rates are known to be sensitive to changes in juvenile and subadult life stages.[159]

f. Benefits From Reduced Mortality of T&E Sea Turtles

The U.S. range of loggerhead sea turtles includes the Gulf of Mexico, South Atlantic, Mid-Atlantic, and North Atlantic 316(b) regions.[160] To calculate national WTP for an increased 25-year survival probability of loggerhead sea turtles, EPA assumed the affected population to include households in States with 316(b) facilities that are in loggerhead sea turtle habitat. EPA determined that 54.8 million households would be willing to pay for improved protection of loggerhead sea turtles. Although incidences of mortality have been reported at facilities in California, Texas, Florida, South Carolina, North Carolina, and New Jersey, EPA does not have sufficient information to quantify total sea turtle losses due to intakes or the reductions in such losses that might occur from the final rule or options considered. But as an illustrative example, assuming that the survival probability of loggerhead sea turtles over 25 years were increased by 1 percent, and applying a mean household value of $0.37 (2011 dollars), the monetized value would be $19.3 million and $18.8 million using discount rates of 3 percent and 7 percent, respectively. EPA is presenting these estimates only to demonstrate the potential range of benefits, and is not including them in national benefits totals for the final rule and options considered. Actual household values and total benefits may be higher or lower than these estimates, with Proposal Option 2 likely to provide substantially greater benefits than the final rule and Proposal Option 4.

Because EPA does not currently have accurate national estimates of impingement mortality and entrainment for turtle species, nor are population models available that estimate the effect of 316(b) regulation on population size and extinction risk, these estimates are presented only as an illustrative example and are not included in national totals.

g. Other Indications of Society's WTP for Protection of T&E Species

Many sources provide information that indicates that society places significant value on protecting T&E species. These include, but are not limited to:

- The Endangered Species Act of 1973, which provides for the conservation of T&E species of fish and wildlife. Federal and State expenditures on T&E species were $593 million during fiscal year 2011 just on protection of those Federally-listed T&E species that have habitat overlapping cooling water intake structures. This accounted for 68 percent of the $869 million spent on fish, marine reptiles, crustaceans, corals, clams, aquatic snails and marine mammals listed under the Endangered Species Act.[161]

[153] Richardson, L., and J. Loomis. 2009. The total economic value of threatened, endangered and rare species: An updated meta-analysis. Ecological Economics, 68(5): 1535–1548.

[154] Bell, K.P., D. Huppert, and R.L. Johnson. 2003. Willingness to pay for local coho salmon enhancement in coastal communities. Marine Resource Economics, 18: 15–31.

[155] Berrens, R.P., P. Ganderton, and C.L. Silva. 1996. Valuing the protection of minimum instream flow in New Mexico. Journal of Agricultural and Resource Economics 21(2): 294–309.

[156] Whitehead, J.C. 1993. Total economic values for coastal and marine wildlife: specification, validity, and valuation issues. Marine Resource Economics, 8(2): 119–132.

[157] Plotkin, P.T., (Ed). 1995. National Marine Fisheries Service and U. S. Fish and Wildlife Service Status Reviews for Sea Turtles Listed under the Endangered Species Act of 1973. National Marine Fisheries Service. Silver Spring, MD.

[158] Crouse, D.T., L.B. Crowder, and H. Caswell. 1987. A stated-based population model for loggerhead sea turtles and implications for conservation. Ecology, 68(5): 1412–1423.

[159] Ibid.

[160] U.S. Fish and Wildlife Service (USFWS) (2010c). ''North Florida Ecological Services Office: Loggerhead Sea Turtle (Caretta).'' Available at *http://www.fws.gov/northflorida/seaturtles/turtle%20factsheets/loggerhead-sea-turtle.htm*.

[161] U.S. Fish and Wildlife Service. 2012. Federal and State Endangered and Threatened Species Expenditures. Fiscal Year 2011.

- Restrictions on activities in the habitat occupied by T&E species. For example, water diversions on the San Joaquin-Sacramento River delta, in place to protect the Delta Smelt (*Hypomesus transpacificus*), limit the extraction of water for drinking and agriculture.
- The willingness of individuals to volunteer their time to conserve T&E species. For example, dozens of organizations recruit thousands of volunteers every year to participate in sea turtle conservation and research projects. Volunteers are often required to undergo substantial training and commit to long hours.

While costs to replace, protect, or enhance stocks, and costs to users affected by efforts to conserve stocks are not direct measures of economic benefits, they indicate that society is willing to pay significant sums to protect and restore populations of T&E species. Although impingement mortality and entrainment is only one of many stressors on these species, reducing the amount of impingement mortality and entrainment could contribute to the recovery of populations over time, thereby eliminating some costs associated with conserving T&E species.

7. Assessment of Thermal Discharge Impacts

In addition to reducing total impingement mortality and entrainment, closed-cycle cooling reduces thermal pollution. Most retrofit installations of cooling towers at electric generating facilities have been required by NPDES permits to reduce thermal discharges. Since thermal discharges are a product of cooling water intake structures, the impacts of thermal discharges are a relevant benefit to consider when assessing appropriate technologies to reduce the effects of cooling water intakes. The installation of technologies, such as closed-cycle cooling systems, can reduce thermal pollution significantly. Thermal pollution has long been recognized to cause harm to the structure and function of aquatic ecosystems. Concerns about the impacts of thermal discharges are addressed by State water quality standards that, when implemented through NPDES permits, limit the amount of heat that can be discharged to a receiving water and result, in some cases, in technology-based permit conditions. Section 316(a) of the CWA applies to point sources with thermal discharges. It authorizes the NPDES permitting authority to impose alternative effluent limitations for the control of the thermal component of a discharge in lieu of the effluent limitations that would otherwise be required under sections 301 or 306 of the CWA. Before such a ''thermal variance'' can be granted, the permittee must demonstrate that the alternative limit will assure the protection and propagation of a balanced, indigenous population of shellfish, fish and wildlife in and on the body of water into which the discharge is to be made. 40 CFR 125.73(a).

EPA did not quantify nationally the impacts of thermal discharges. However, numerous studies have shown that thermal discharges may substantially alter the structure of aquatic communities by modifying photosynthetic, metabolic, and growth rates. Thermal discharges also harm aquatic life by reducing levels of dissolved oxygen, altering the location and timing of fish behavior such as spawning, aggregation, and migration, and may cause thermal shock-induced mortality for some species. Adverse temperature effects may also be more pronounced in aquatic ecosystems that are already subject to other environmental stressors such as high levels of biochemical oxygen demand, nutrient and sediment contamination, or pathogens. Within mixing zones, which often extend several miles downstream from outfalls, thermal discharges may impair efforts to restore and protect the waterbody. For example, permit requirements to limit nitrogen discharges in a watershed, and thereby reduce harmful algal blooms, may be counteracted by thermal discharges which promote growth of harmful algae. Thermal discharges may have indirect effects on fish and other vertebrate populations through increasing pathogen growth and infection rates.

Thermal discharges may thus alter the ecological services, and reduce the benefits, of aquatic ecosystems that receive heated effluent. The magnitude of thermal effects on ecosystem services is related to facility-specific factors, including the volume of the waterbody from which cooling water is withdrawn and returned, other heat loads, the rate of water exchange, the presence of nearby refugia, and the assemblage of nearby fish species.

8. Assessment of Social Cost of Carbon

The social cost of carbon reflects the estimated increase in the burden of global warming to society in future years due to higher greenhouse gas (GHG) emissions, measured as CO_2 equivalents, associated with additional energy requirements—energy penalty, auxiliary energy requirements, and compliance technology installation—of regulatory options. EPA estimated positive or negative benefits associated with the social cost of carbon for decreases or increases, respectively for Proposal Option 4 and Final Rule or Proposal Option 2, in energy requirements at regulated facilities under the final rule and other options considered.

EPA's estimates of changes in CO_2 emissions were based on results from the electricity market analysis using IPM.[162] For electric generators, EPA estimated the change in CO_2 resulting from the energy penalty associated with close-cycle recirculating technology, auxiliary energy requirement for operating compliance technology, and technology installation downtime. For manufacturers, EPA estimated the change in carbon emissions resulting from the energy penalty and auxiliary energy requirement. For compliance technology installation downtime at manufacturers, EPA assumed no change in carbon emissions as the short-term replacement of energy by electric power generating facilities that would otherwise be produced at manufacturers could either increase or decrease emissions.

To estimate benefits associated with the reductions in carbon emissions, EPA used social cost of carbon values calculated from the 2013 document titled, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, developed by the U.S. Government Interagency Working Group on Social Cost of Carbon. The Agency used the Working+ Group's annual social cost of carbon values for 2010 through 2050 based on the 3 percent average discount rate, which EPA has concluded is the most appropriate discount rate for intergenerational benefits such as the social cost of carbon. See Chapter 9 of the BA for annual social cost of carbon values based on discount rates of 2.5, 3 (high) and 5 percent. Benefits for each year of the analysis period were calculated by multiplying the change CO_2 emissions by the SCC value for that year. Similar to the treatment of other benefits, EPA discounted all year-specific social cost of carbon values to the beginning of 2013 and calculated an annualized value over 51 years using a 3-percent discount rate. EPA acknowledges that it is mixing estimates of benefits categories analyzed at different discount rates, but finds in this

[162] For this analysis, EPA used the Integrated Planning Model (IPM®), a comprehensive electricity market optimization model that assesses such impacts within the context of regional and national electricity markets.

case that using different discount rates is justified by the intergenerational nature of the social cost of carbon, for purposes of the sensitivity analysis based on a 7 percent discount rate to discount other benefit categories.

Exhibit X–11 presents annualized benefits for existing units for the final rule and options considered. Included in the monetized benefits is EPA's estimate that the final rule will reduce greenhouse gas emissions by 9.3 million tons of CO_2-equivalent emissions over the 40-year compliance period for this analysis. Both the final rule and Proposal Option 4 result in a net reduction in CO_2 emissions for existing units during the analysis period. Proposal Option 2 would result in a net increase in emissions and negative benefits for existing units. Using a 3 percent discount rate, annualized benefits under the final rule for existing units are $12 million. Using a 7 percent discount rate, annualized benefits under final rule for existing units are $13 million.

EXHIBIT X–11—BENEFITS ASSOCIATED WITH SOCIAL COST OF CARBON FOR EXISTING UNITS FOR THE FINAL RULE AND OTHER OPTIONS CONSIDERED

[In millions of 2011 dollars] [a]

Regulatory option [b]	3% Discount rate	7% Discount rate
Proposal Option 4	12.4	13.4
Final Rule—Existing Units	12.4	13.4
Proposal Option 2	−1,643.1	−1,218.2

[a] Benefits are based on the workgroup's average social cost of carbon values using 3 percent rate.

9. Benefits for New Units

In addition to the final rule and other options considered for existing units, EPA analyzed the benefits of the requirements for new units at existing facilities. EPA could not directly apply the benefits methodology used for IM&E (impingement mortality and entrainment) reductions at existing units to new units because it lacks facility-specific information to estimate regional impingement mortality and entrainment reductions for new units. Instead, EPA estimated benefits associated with IM&E reductions for the new unit requirements on the basis of the monetary benefits per million gallons per day from the analysis of existing units. EPA also estimated benefits associated with changes in GHG emissions as the result of the energy penalty associated with operating cooling towers using the social cost of carbon. Exhibit X–12 below presents the estimates of monetized benefits for the new unit requirements. Monetized benefits are −$0.2 million discounted at 3 percent and −$0.1 million discounted at 7 percent.

EXHIBIT X–12—NATIONAL BENEFITS UNDER THE FINAL RULE FOR NEW UNITS AT EXISTING FACILITIES

[In 2011 dollars]

Regulatory option [a]	Monetized benefit categories					
	Recreational fishing	Commercial fishing	Nonuse	T&E species [b]	Social cost of carbon [c]	Total
3% discount rate (millions 2011$)						
Final Rule—New Units	0.0	0.0	0.1	0.0	−0.3	−0.2
7% discount rate (millions 2011$)						
Final Rule—New Units	0.0	0.0	0.0	0.0	−*0.2*	−0.1

[a] IM&E Effects: Final Rule—New Units—entrainment requirements for all stand-alone facilities.
[b] Benefits estimates for T&E species are restricted to recreational fishing benefits from increased catch of T&E species. They do not include benefits for reduced mortality of T&E sea turtles and other nonuse values associated with T&E species.
[c] Benefits are based on the Work Group's average social cost of carbon values using the 3 percent rate.

10. National Monetized Benefits

Quantifying and monetizing reductions in impingement mortality and entrainment attributable to the final rule and other options considered is challenging. National benefit estimates are subject to uncertainties inherent in valuation approaches used to assess the benefits categories (see Chapters 5, 6, 7, 8, 9, and 12 of the BA). While EPA has no data to indicate that the results for each benefit category are atypical or unreasonable, some potentially significant benefit categories have not been fully monetized, and thus the national monetized benefits presented below likely underestimate total benefits.

Exhibit X–13 presents EPA's estimates of the partial monetized benefits from impingement mortality and entrainment reduction and the social cost of carbon for the final rule and other options considered. These monetized values represent use values from increased commercial and recreational catch, benefits transfer of recreational fishing benefits of threatened and endangered species, nonuse values associated with an increase in fish abundance (those fish that are not caught) in the Northeast and Mid-Atlantic benefit regions, and national benefits estimates associated with the social cost of carbon. For the final rule for existing and new units, partial estimated benefits from reducing impingement mortality and entrainment at existing units are $33 million using a 3 percent discount rate and $29 million using a 7 percent discount rate. EPA was not able to fully monetize the benefits for the final rule. Thus, the estimates represent a conservative (i.e., low) estimate of total regulatory benefits of the final rule.

EXHIBIT X–13—SUMMARY OF NATIONAL BENEFITS FOR ALL REGULATED FACILITIES FOR THE FINAL RULE

Regulatory option [a]	Monetized benefit categories					
	Recreational fishing	Commercial fishing	Nonuse	T&E species [b]	Social cost of carbon [c]	Total
3% discount rate (millions 2011$)						
Final Rule—Existing Units	18.2	0.9	1.0	0.4	12.4	33.0
Final Rule—New Units	0.0	0.0	0.1	0.0	−0.3	−0.2
Final Rule (Existing Units + New Units)	18.3	0.9	1.1	0.4	12.1	32.8
7% discount rate (millions 2011$)						
Final Rule—Existing Units	13.5	0.7	0.8	0.3	13.4	28.7
Final Rule—New Units	0.0	0.0	0.1	0.0	−0.2	−0.1
Final Rule (Existing Units + New Units)	13.5	0.7	0.9	0.3	13.2	28.6

[a] IM&E Effects: Final Rule–Existing Units = impingement mortality standards based on modified traveling screens for all facilities with flow greater than 2 mgd; Final Rule–New Units: Entrainment requirements for all stand-alone facilities where the turbine and condenser are newly built or replaced.
[b] Benefits estimates for T&E species are restricted to benefit transfer of recreational fishing benefits from T&E species. They do not include benefits for reduced mortality of T&E sea turtles and other nonuse values associated with T&E species.
[c] Baseline does not include potential benefits associated with the social cost of carbon.

Exhibit X–14 presents total monetized benefits for the final rule and other options EPA considered for existing units by benefit category using a 3 percent discount rate. Annual monetized benefits are slightly higher for the final rule than Proposal Option 4, and are negative for Proposal Option 2. Including both existing and new units, annual monetized benefits are $32.8 million for the final rule, $30.8 million for Proposal Option 4 and −$1,542.8 million for Proposal Option 2.

EXHIBIT X–14—SUMMARY OF NATIONAL BENEFITS FOR ALL REGULATED FACILITIES FOR THE FINAL RULE AND OTHER OPTIONS EPA CONSIDERED

[3% Discount rate]

Monetized benefit categories	Annual benefits by regulatory option [a] (*millions 2011$*)		
	Proposal option 4	Final rule—existing units	Proposal option 2
Existing Units			
Recreational Fishing	17.1	18.2	43.0
Commercial Fishing	0.9	0.9	3.9
Nonuse	0.3	1.0	51.1
T&E Species [b]	0.4	0.4	0.7
Social Cost of Carbon	12.4	12.4	−1,641.3
Total	31.0	33.0	−1,542.6
Final Rule—New Units			
Total	−0.2	−0.2	−0.2
Existing and New Units			
Total	30.8	32.8	−1,542.8

[a] IM&E Effects: Proposal Option 4 = impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 50 mgd; Final Rule—Existing Units = impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 2 mgd; Proposal Option 2 = impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 2 mgd and entrainment mortality limitations commensurate with closed-cycle recirculating systems for all facilities with flow greater than 125 DIF; Final Rule—New Units: entrainment requirements for all stand-alone facilities.
[b] Benefits estimates for T&E species are restricted to benefit transfer of recreational fishing benefits from T&E species. They do not include benefits for reduced mortality of T&E sea turtles and other nonuse values associated with T&E species.

EPA recognizes that its estimates of ecological and economic benefits projected to occur under regulation are affected by uncertainty at many levels.

- Not all ecological goods and services affected by cooling water intake structures at regulated 316(b) facilities are modeled or monetized, suggesting that the total benefits of regulation may be underestimated. For example, potential increases in ecosystem stability that might occur as a result of regulation is not explicitly estimated nor monetized.
- When particular ecological goods and services are monetized, data is not always available at the national level. For example, EPA was only able to estimate the nonuse benefits transfer for a species that represents less than one

percent of adverse environmental impacts.

- For the proposed rule, EPA used a habitat-based method to assess potential WTP for reducing fish mortality at CWIS based on the approximate area of habitat required to produce and support the number of organisms lost to impingement mortality and entrainment.[163] EPA did not consider the habitat-based approach appropriate for primary analysis of benefits for the proposed rule, and did not include it in its analysis for the final rule. However, the results for the proposed rule illustrate that total benefits may be substantially greater than benefits estimated using the methodologies described in Section D.

Because EPA was able to only partially monetize nonuse benefits using the benefits transfer approach, EPA expects that the actual benefits will be greater than those presented here.

XI. Related Acts of Congress, Executive Orders, and Agency Initiatives

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

Under section 3(f)(1) of E.O. 12866 (58 FR 51735, October 4, 1993), this action is an *economically significant regulatory action* because it is likely to have an annual effect of $100 million or more on the economy. Accordingly, EPA submitted this action to the Office of Management and Budget for review under E.O. 12866 and 13563 (76 FR 3821, January 21, 2011), and any changes made in response to Office of Management and Budget recommendations have been documented in the docket for this action.

In addition, EPA prepared an analysis of the costs and benefits associated with this action; this analysis is discussed in detail in the Chapter 8 of the EA. A copy of the EA is available in the docket for this action, and the analysis is briefly summarized here.

Exhibit XI–1 (drawn from Chapter 8 of the EA) provides the results of the benefit-cost analysis.[164] Placeholders for option-specific non-monetized benefits are represented by B_{P4} for Proposal Option 4, B_{FR} for the final rule and B_{P2} for Proposal Option 2. While preliminary, and not yet reviewed by EPA's Science Advisory Board, the preliminary results of EPA's stated preference survey (see BA, Chapter 11) suggest that B_{P4}, B_{FR}, and B_{P2} have the potential to be significantly different from zero. EPA is therefore using placeholders for additional benefits that are not captured by its analysis of use benefits and the benefits transfer for nonuse benefits. However, EPA did not rely on the results of its stated preference survey in estimating the benefits of today's rule. EPA has concluded that the benefits of the rule justify the costs.

EPA also analyzed the employment effects of the final rule and other options considered in development of this rule. The results of that analysis are summarized in Section IX.E of this preamble and Chapter 9 of the EA.

EXHIBIT XI–1—ANNUALIZED BENEFITS AND COSTS OF THE REGULATORY OPTIONS

[In millions, 2011 dollars] [a]

Option	Total social costs [b]	Benefits [c]
Proposal Option 4	$251.8	$31.0 + B_{P4}
Final Rule	274.9	32.8 + B_{FR}
Proposal Option 2	3,643.2	−1,542.6 + B_{P2}

[a] Social costs and benefits were annualized over 51 years and discounted using 3 percent rate.
[b] Total social costs include compliance costs to facilities and government administrative costs. See EA Chapter 7.
[c] Benefits include social cost of carbon from changes in greenhouse gas emissions due to the final rule.

B. Paperwork Reduction Act

The information collection requirements in this rule will be submitted for approval to the Office of Management and Budget (OMB) under the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* The supporting statement in EPA's information collection request estimates the burden to permitted facilities; burden is defined at 5 CFR 1320.3(b). The 60-day comment period will commence after publication of the draft ICR. The information collection requirements are not enforceable until they are approved by OMB.

Today's rule requires several distinct types of information collection as part of the NPDES permit application. In general, the information will be used to assist EPA in regulating environmental impacts, namely impingement mortality and entrainment, at cooling water intake structures and to identify how a cooling water intake structure at an existing facility or a new unit at an existing facility will meet the impingement mortality and entrainment requirements. Today's rule also requires other reporting and recordkeeping requirements to demonstrate and document compliance with the requirements. Compliance with the applicable information collection requirements established under this final rule is mandatory (see §§ 122.21(r), 125.136, 125.137, 125, and 138).

EPA does not consider the specific data that will be collected under this final rule to be confidential business information. However, if a respondent does consider this information to be confidential, the respondent may request that such information be treated as confidential. All confidential data submitted to EPA will be handled in accordance with 40 CFR 122.7, 40 CFR part 2, and EPA's Security Manual Part III, Chapter 9, dated August 9, 1976.

This final rule modifies regulations at § 122.21 to require each existing facility and new unit at an existing facility to prepare and submit information as part of the facility's NPDES permit application. A detailed list of required data items is provided below.

EPA estimates an average annual burden of 634,596 hours for the final rule's information collection requirements. Of this total, EPA estimates that 1,068 regulated facilities

[163] U.S. EPA. 2011. Environmental and Economic Benefits Analysis for the Proposed Section 316(b) Existing Facilities Rule.

[164] The costs and benefits presented in this section assume that facilities with impoundments will qualify as having closed-cycle recirculating systems in the baseline EPA also conducted the costs and impacts analysis where impoundments were not assumed to meet the definition of closed-cycle recirculating. EPA did not find that this assumption would change EPA's final rule decision; see DCN 12–2501.

will incur an annual average burden of 588 hours per respondent (for a total of 627,666 burden hours). EPA estimates that Directors in 46 States and one territory with NPDES permitting authority, will incur an annual average burden for the review, oversight, and administration of the rule, of 6,930 hours, or an annual average of 147 hours per permitting authority. Slight differences in calculations are due to rounding.

The corresponding estimate of costs other than labor (labor and non-labor costs are included in the total cost of the final rule discussed in Section IX of this preamble) during the first three years after promulgation of the rule is an annual average of $8.5 million. Non-labor costs include activities such as capital costs for sampling equipment, remote monitoring devices, laboratory services, photocopying, and the purchase of supplies. The burden and costs are for the information collection, reporting, and recordkeeping requirements for the three-year period beginning with the assumed effective date of this rule. Additional information collection requirements will occur after this initial three-year period as (1) existing facilities will continue to gather and submit required permit application materials and (2) new units at existing facilities commence operations and are issued permits.

Information and studies to be submitted under this final rule (as required by §§ 122.21(r) and 125.95) by existing facilities and new units at existing facilities are listed below. For more information, see Section VIII in the preamble.

- Source Water Physical Data (§ 122.21(r)(2))
- Cooling Water Intake Structure Data (§ 122.21(r)(3))
- Source Water Baseline Biological Characterization Data (§ 122.21(r)(4))
- Cooling Water System Data (§ 122.21(r)(5))
- Chosen Method of Compliance With Impingement Mortality Standards (§ 122.21(r)(6))
- Performance Studies (§ 122.21(r)(7))
- Operational Status (§ 122.21(r)(8))
- Entrainment Characterization Study (§ 122.21(r)(9))
- Comprehensive Technical Feasibility and Cost Evaluation Study (§ 122.21(r)(10))
- Benefits Valuation Study (§ 122.21(r)(11))
- Non-Water Quality and Other Environmental Impacts Study (§ 122.21(r)(12))

In addition to the information requirements of the permit application, NPDES permits normally specify monitoring and reporting requirements to be met by the permitted entity. Existing facilities and new units at existing facilities are required to perform monitoring as determined by the requirements in § 125.94 and in accordance with §§ 125.96 and 125.97.

Finally, in accordance with § 125.95(e), facilities are required to maintain records of all submissions that are part of its permit application for a minimum of five years. If the Director approves a request for reduced permit application studies under § 125.95(a) or § 125.98(g), the facility must keep records of all submissions that are part of a previous permit application for an additional five years. Also, facilities must keep records of all submissions that are part of the permit reporting requirements for a period of at least five years from the date of permit issuance, in accordance with § 125.97(d).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9.

C. Regulatory Flexibility Act (RFA)

The Regulatory Flexibility Act generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

1. Definition of Small Entities and Estimation of the Number of Small Entities Subject to Today's Final Regulation

For EPA's assessment of the impact of today's final rule on small entities, *small entity* is defined as either (1) a small business as defined by SBA (Small Business Administration) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of fewer than 50,000; or (3) a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field. Federal or State entities owning regulated facilities are not small entities.

EPA performed this assessment separately for the two classes of facilities and their owner entities—electric generators and manufacturers—that are subject to today's rule.

a. Electric Generators

EPA followed the SBA criteria for identifying small, non-government entities in the electric power industry, as follows:

- For non-government entities with electric power generation as a primary business, small entities were designated using employment size thresholds specific to each 6-digit NAICS code.
- For government entities other than Federal or State governments, small entities are those with a population of fewer than 50,000.
- For entities with a primary business other than electric power generation, the relevant size criteria are based on revenue or number of employees by NAICS sector (see Exhibit XI–2).

EXHIBIT XI–2—NAICS CODES AND SBA ENTITY SIZE STANDARDS FOR ENTITIES THAT OWN ELECTRIC GENERATORS WITH A PRIMARY BUSINESS OTHER THAN ELECTRIC POWER GENERATION

NAICS code	NAICS description	SBA size standard
212111	Bituminous Coal and Lignite Surface Mining	500 employees.
221210	Natural Gas Distribution	500 employees.
331110	Iron and Steel Mills and Ferroalloy Manufacturing	1,000 employees.
331315	Aluminum Sheet, Plate, and Foil Manufacturing	750 employees.
333611	Turbine and Turbine Generator Set Units Manufacturing	1,000 employees.
488320	Marine Cargo Handling	$35.5 million in revenue.
491110	Postal Service	$7 million in revenue.
522110	Commercial Banking	$175 million in assets.
523910	Miscellaneous Intermediation	$7 million in revenue.
524126	Direct Property and Casualty Insurance Carriers	1,500 employees.

EXHIBIT XI–2—NAICS CODES AND SBA ENTITY SIZE STANDARDS FOR ENTITIES THAT OWN ELECTRIC GENERATORS WITH A PRIMARY BUSINESS OTHER THAN ELECTRIC POWER GENERATION—Continued

NAICS code	NAICS description	SBA size standard
525910	Open-End Investment Funds	$7 million in revenue.
525990	Other Financial Vehicles	$7 million in revenue.
541990	All Other Professional, Scientific, and Technical Services	$14 million in revenue.
551112	Offices of Other Holding Companies	$7 million in revenue.
562212	Solid Waste Landfill	$35.5 million in revenue.
562219	Other Nonhazardous Waste Treatment and Disposal	$35.5 million in revenue.
562920	Materials Recovery Facilities	$19 million in revenue.
611310	Colleges, Universities, and Professional Schools	$25.5 million in revenue.

EPA conducted this analysis for the same set of parent entities it analyzed in the general entity-level cost-to-revenue analysis discussed in Section IX.D. To determine whether these are small entities on the basis of the size criteria outlined above, EPA compared the relevant measure for the identified parent entities to the appropriate SBA size criterion. EPA conducted this analysis using (1) facility-level weights without using entity-level weights, and (2) entity-level weights without using facility-level weights (for information on these two weighting approaches, see Appendix H of the EA).

EPA estimates that between 31 and 52 small entities own electric generators that are subject to the rule. They represent approximately 25 to 32 percent of entities that own electric generators (see Exhibit XI–3).

EXHIBIT XI–3—NUMBER OF ENTITIES THAT OWN ELECTRIC GENERATORS, BY OWNERSHIP TYPE

Ownership type [a]	Using facility-level weights			Using entity-level weights [b]		
	Total	Small	% Small	Total	Small	% Small
Cooperative	13	11	84.6	21	18	85.7
Federal	1	0	0.0	1	0	0.0
Investor-owned	57	6	10.5	60	7	11.7
Municipality	19	7	36.8	38	19	50.0
Nonutility	26	7	26.9	30	8	26.7
Other Political Subdivision	4	0	0.0	6	0	0.0
State	3	0	0.0	3	0	0.0
All Entity Types	123	31	25.2	159	52	32.7

[a] State and Federal entities are considered large.
[b] In addition to the 52 small parent entities on an unweighted basis, one additional entity is an "other political subdivision entity" for a total of 53. This entity owns only implicitly analyzed facilities; consequently, there is no explicitly analyzed entity in the other political subdivision ownership category to represent this implicitly analyzed small parent entity. As the result, weighted entity counts do not include one small other political subdivision entity.

b. Manufacturers

EPA also used the SBA criteria for identifying small, non-government entities in the manufacturing sector. Exhibit XI–4 lists the SBA size threshold guidelines for entities that own manufacturers.

EXHIBIT XI–4—NAICS CODES AND SBA ENTITY SIZE STANDARDS FOR ENTITIES THAT OWN MANUFACTURERS

NAICS code	NAICS description	SBA size standard
111930	Sugarcane Farming	$0.75 million in revenue.
113110	Timber Tract Operations	$7 million in revenue.
211111	Crude Petroleum and Natural Gas Extraction	500 employees.
212210	Iron Ore Mining	500 employees.
212391	Potash, Soda, and Borate Mineral Mining	500 employees.
221122	Electric Power Distribution	4,000,000 MWh of electric generation.
311221	Wet Corn Milling	750 employees.
311314	Cane Sugar Manufacturing	750 employees.
311313	Beet Sugar Manufacturing	750 employees.
311942	Spice and Extract Manufacturing	500 employees.
313210	Broadwoven Fabric Mills	1,000 employees.
321113	Sawmills	500 employees.
322121	Paper (except Newsprint) Mills	750 employees.
322122	Newsprint Mills	750 employees.
322130	Paperboard Mills	750 employees.
322211	Corrugated and Solid Fiber Box Manufacturing	500 employees.
322220	Paper Bag and Coated and Treated Paper Manufacturing	500 employees.
322291	Sanitary Paper Product Manufacturing	500 employees.
324110	Petroleum Refineries	1,500 employees.

EXHIBIT XI–4—NAICS CODES AND SBA ENTITY SIZE STANDARDS FOR ENTITIES THAT OWN MANUFACTURERS—Continued

NAICS code	NAICS description	SBA size standard
324191	Petroleum Lubricating Oil and Grease Manufacturing	500 employees.
325120	Industrial Gas Manufacturing	1,000 employees.
325180	Other Basic Inorganic Chemical Manufacturing	1,000 employees.
325199	All Other Basic Organic Chemical Manufacturing	1,000 employees.
325211	Plastics Material and Resin Manufacturing	750 employees.
325311	Nitrogenous Fertilizer Manufacturing	1,000 employees.
325320	Pesticide and Other Agricultural Chemical Manufacturing	500 employees.
325412	Pharmaceutical Preparation Manufacturing	750 employees.
325510	Paint and Coating Manufacturing	500 employees.
325992	Photographic Film, Paper, Plate and Chemical Manufacturing	500 employees.
325998	All Other Miscellaneous Chemical Product and Preparation Manufacturing	500 employees.
331110	Iron and Steel Mills and Ferroalloy Manufacturing	1,000 employees.
331210	Iron and Steel Pipe and Tube Manufacturing from Purchased Steel	1,000 employees.
331221	Rolled Steel Shape Manufacturing	1,000 employees.
331222	Steel Wire Drawing	1,000 employees.
331313	Alumina Refining and Primary Aluminum Production	1,000 employees.
331315	Aluminum Sheet, Plate and Foil Manufacturing	750 employees.
331410	Nonferrous Metal (except Aluminum) Smelting and Refining	1,000 employees.
332312	Fabricated Structural Metal Manufacturing	500 employees.
337910	Mattress Manufacturing	500 employees.
339999	All Other Miscellaneous Manufacturing	500 employees.
423310	Lumber, Plywood, Millwork, and Wood Panel Merchant Wholesalers	100 employees.
423930	Recyclable Material Merchant Wholesalers	100 employees.
424510	Grain and Field Bean Merchant Wholesalers	100 employees.
424690	Other Chemical and Allied Products Merchant Wholesalers	100 employees.
424710	Petroleum Bulk Stations and Terminals	100 employees.
447190	Other Gasoline Stations	$14 million in revenue.
522220	Sales Financing	$7 million in revenue.
523910	Miscellaneous Intermediation	$7 million in revenue.
523930	Investment Advice	$7 million in revenue.
524126	Direct Property and Casualty Insurance Carriers	1,500 employees.
525990	Other Financial Vehicles	$7 million in revenue.
531110	Lessors of Residential Buildings and Dwellings	$25 million in revenue.
551112	Offices of Other Holding Companies	$7 million in revenue.
561110	Office Administrative Services	$7 million in revenue.

Similar to the analysis conducted for electric generators, EPA conducted this analysis for the same set of parent entities as analyzed in the general, entity-level, cost-to-revenue analysis discussed in Section IX.D. To determine which entities are small, EPA compared the relevant measure for the identified parent entities to the appropriate SBA size criterion. EPA used two sample-weighting schemes in this analysis; these provide a range of counts of small entities that own regulated facilities and the number of regulated facilities that they own that will incur costs under the final rule. EPA does not find either of these sample-weighting schemes to be superior to the other in the quality of the resulting estimates of small entity counts and occurrence of impacts. The different weighting approaches reflect the fact that EPA used sample facilities for the impact analysis and lacks precise information on the profile of ownership of the *total population* of regulated manufacturers facilities—in terms of the number of small entities owning regulated facilities and the number of regulated facilities that any small entity would own. EPA developed the weighting schemes using alternative bounding assumptions about the profile of ownership of regulated facilities by small entities. The weighting schemes provide lower and upper bound estimates of the numbers of small entities, and the numbers of regulated facilities that they own, and accordingly, the number of small entities in each of the cost-to-revenue impact categories (for information on the weighting schemes, see Appendix H of the EA).

From this analysis, EPA estimates that 17 to 52 small entities own regulated facilities in the six Primary Manufacturing Industries, representing approximately 16 percent of all entities that own regulated facilities in these industries (see Exhibit XI–5).The presence of small entities varies by industry sector.

EXHIBIT XI–5—NUMBER OF SMALL ENTITIES THAT OWN REGULATED FACILITIES, BY INDUSTRY

Industry	Lower-bound estimate of number of entities that own regulated facilities			Upper-bound estimate of number of entities that own regulated facilities		
	Total	Small	% Small	Total	Small	% Small
Aluminum	4	2	50.0	11	4	40.6
Chemicals and Allied Products	30	5	16.7	121	21	17.7
Food and Kindred Products	6	0	0.0	20	0	0.0
Paper and Allied Products	37	7	18.9	104	23	21.8
Petroleum Refining	16	2	12.5	25	2	8.4

EXHIBIT XI–5—NUMBER OF SMALL ENTITIES THAT OWN REGULATED FACILITIES, BY INDUSTRY—Continued

Industry	Lower-bound estimate of number of entities that own regulated facilities			Upper-bound estimate of number of entities that own regulated facilities		
	Total	Small	% Small	Total	Small	% Small
Steel	13	1	7.7	32	2	5.2
Multiple Industries [a]	4	0	0.0	14	0	0.0
Primary Manufacturing Industries [b]—Total	110	17	15.5	327	52	16.0

[a] These are small entities that own regulated facilities from multiple industries.
[b] EPA did not compile comparable information for Other Industries facilities and the entities that own them because it did not have a statistically valid sample of facilities from which to develop such estimates.

c. Total Number of Small Entities That Own Regulated Facilities

EPA estimates that between 48 and 104 small entities own regulated facilities in the electric power industry and six primary manufacturing industries together.

2. Statement of Basis

As described above, EPA began the small entity impact assessment by first estimating the number of small entities in the two industry segments subject to the final rule: Electric generators and manufacturers. EPA next assessed whether these small entities would be expected to incur costs that constitute a significant impact and, finally, assessed whether those entities represent a substantial number of small entities.

EPA summed annualized after-tax compliance costs for regulated facilities that are assumed to be owned by a given small entity and calculated the costs as a percentage of entity revenue (cost-to-revenue test). EPA compared the resulting percentages to impact criteria of 1 and 3 percent of revenue. EPA assumed that small entities estimated to incur costs below 1 percent of revenue will not face significant economic impacts, while small entities with costs of at least 1 percent of revenue have a chance of facing economic impacts. EPA assumed that entities incurring costs of at least 3 percent of revenue have a higher likelihood of economic impacts.

For both electric generators and manufacturers, EPA used sample-weighting approaches that provide a range of estimates of the numbers of small entities and regulated facilities that they own.

Exhibit XI–6 summarizes the Regulatory Flexibility Act analysis results under both weighting approaches for each regulated facilities segment. Overall, the RFA analysis for electric generators found that no small entities would potentially incur a significant impact under the final rule. Specifically, for electric generators, EPA estimates that zero to three small entities will incur costs exceeding 1 percent of revenue, while no small entity will incur costs exceeding 3 percent of revenue. Following EPA's guidance on conducting RFA analyses, the number of small entities above the threshold as a percent of all small entities subject to the rule are zero to 10 percent at the 1 percent of revenue threshold, and zero percent at the 3 percent of revenue threshold.

The findings for manufacturers are comparable. Specifically, EPA estimates that three to four small parent entities will incur costs exceeding 1 percent of revenue, and zero to one small parent entity will incur costs exceeding 3 percent of revenue. The associated percentages of small entities subject to the final rule are 8 percent to 18 percent at the 1 percent threshold, and zero percent to 6 percent at the 3 percent threshold.

Combining the electric generators and manufacturers segments, EPA estimates that three to seven small entities will incur costs exceeding 1 percent of revenue, while zero to one small entity will incur costs exceeding 3 percent of revenue. The corresponding percentages of small entities are 4 to 13 percent at the 1 percent threshold, and zero to 2 percent at the 3 percent threshold.

In summary, under the final rule, EPA estimates that a small number of small parent entities will incur a potentially significant cost impact in the individual regulated industry segments, and overall, for both segments. The maximum number of small entities estimated to incur costs exceeding 1 percent is seven, overall, with three of these small entities in the electric generators segment and four in the manufacturers segment. The maximum number of small entities with costs exceeding 3 percent is one, overall, with no small entities in the electric generators segment and one small entity in the manufacturers segments. In each case, the maximum value reflects the high end of an uncertainty range that is based on different sample weighting approaches. EPA judges that values in the interior of these ranges represent more reasonable estimates of the number of small entities incurring significant impacts. The estimated numbers of entities with significant impacts also represent small percentages of the estimated number of small entities, overall, and in the individual segments. The maximum percentage values at the 1 percent of revenue threshold are 13 percent, overall, 10 percent for electric generators, and 18 percent for manufacturers. At the 3 percent threshold, the maximum percentage values are 2 percent, overall, zero percent for electric generators, and 6 percent for manufacturers. Again, these values reflect the high end of an uncertainty range.

In view of these very modest impacts, EPA judges that the final rule is not consequential in terms of potential impacts for small entities.

EXHIBIT XI–6—ESTIMATED COST-TO-REVENUE IMPACT FOR SMALL ENTITIES THAT OWN FACILITIES SUBJECT TO THE REGULATION

Regulated Segment	Cost impact category			
	Cost ≥1% of revenue [a]		Cost ≥3% of revenue [a]	
	Number of small entities	% of small regulated entities [b]	Number of small entities [c]	% of small regulated entities [b]
Electric Generators	0 to 3	0% to 10%	0	0%
Manufacturers [d]	3 to 4	8% to 18%	0 to 1	0% to 6%
Electric Generators and Manufacturers [d]	3 to 7	4% to 13%	0 to 1	0% to 2%

[a] For both electric generators and manufacturers, EPA used sample-weighting approaches that provide a range of estimates of the numbers of small entities and regulated facilities they own (see Section VII(D)(a)(iv) for manufactures and see Section VII(D)(b)(1)(b) for electric generator weighting approaches).

[b] Percentage of small entities incurring a cost-to-revenue impact involves range estimates in both the numerator (number of affected entities) and denominator (number of regulated entities).

[c] Entities with cost-to-revenue ratios of at least 3 percent are included in the number of entities with cost-to-revenue such ratios of at least 1 percent.

[d] Entity counts used in these calculations exclude manufacturers in other industries. EPA estimated that one small parent entity that owns regulated facilities in other industries would incur costs exceeding 1 percent of revenue.

3. Certification Statement

Given these findings of very small absolute numbers of small entities estimated to incur significant impacts under the final rule, and low percentages of estimated small entities incurring impacts, I certify that the final rule will not have ''a significant impact on a substantial number of small entities'' (no SISNOSE), overall and by individual industry segment.

D. Unfunded Mandates Reform Act (UMRA)

Title II of the Unfunded Mandates Reform Act of 1995, 2 U.S.C. 1531–1538, requires Federal agencies, unless otherwise prohibited by law, to assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Today's rule contains a Federal mandate that may result in expenditures by State, local, and Tribal governments, in the aggregate, or the private sector, of $100 million or more (adjusted annually for inflation) in any one year. Accordingly, under Unfunded Mandates Reform Act section 202, EPA has prepared a written statement, which follows below (see Chapter 11 of the EA).

1. Summary of Written Statement

a. Authorizing Legislation

Today's rule is issued under the authority of CWA sections 101, 301, 304, 306, 308, 316, 401, 402, 501, and 510, (33 U.S.C. 1251, 1311, 1314, 1316, 1318, 1326, 1341, 1342, 1361, and 1370). For detailed information on the legal authority of this rule, see Section III of this preamble.

b. Benefit-Cost Analysis

As described above, the costs, benefits and economic impacts reported in this section may be underestimated due to EPA's assumption that facilities with impoundments will qualify as having closed-cycle recirculating systems in the baseline and thus, unless additional controls are required to protect listed species, will incur no technology-related costs. Likewise, for this analysis, because these facilities are assumed not to install compliance technology, EPA also assumed they would achieve no benefits. Accordingly, the benefits reported in this section may be underestimated, based on the assumption of no technology installation for facilities with impoundments.[165] The existing and new unit provisions of today's rule are expected to have total annualized pre-tax (social) costs of $274.9 million. These costs include direct costs incurred by facilities and implementation costs incurred by Federal, State, and local governments. The monetized use and nonuse benefits of the final rule, accounting for the existing and new unit provisions, are estimated to be $32.8 million.[166] EPA notes that these differences are based on a comparison of a partial measure of benefits with a more complete measure of costs; therefore, the results must be interpreted with caution. For a more detailed comparison of the costs and benefits of the final rule, see Chapter 8 of the EA.

[165] This factor in potential underestimation of benefits is separate from other considerations that likely lead to benefits underestimation, as described in this section and in the EA and BA reports.

[166] Both cost and benefit values were annualized over 51 years and discounted at 3 percent. Values include costs and benefits estimated for new units. EPA generated partial estimates of nonuse benefits for resource changes for a species that represents less than one percent of adverse environmental impacts.

EPA notes that States may be able to use existing sources of financial assistance to revise and implement today's rule. CWA section 106 authorizes EPA to award grants to States, Tribes, intertribal consortia, and interstate agencies for administering programs for the prevention, reduction, and elimination of water pollution. These grants may be used for various activities to develop and carry out a water pollution control program, including permitting, monitoring, and enforcement. Thus, State and Tribal NPDES permit programs represent one type of State program that can be funded by CWA section 106 grants.

c. Summary of State, Local, and Tribal Government Input

EPA consulted with State governments and representatives of local governments in developing the rule. The outreach activities are discussed in Section III.A.3 of the preamble to the proposed rule (see 76 FR 22268, April 20, 2011) and Chapter 2 of the TDD. EPA has also conducted additional outreach since the proposed rule, including several conference calls with the Association of Clean Water Administrators (including numerous states) and small business representatives (including some local government officials). EPA also combined its efforts and collected input from State and local government entities during development of the proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, which shares many of the same affected facilities as today's final rule; see 78 FR 34530 (June 7, 2013) for more information. State and local officials attended numerous site visits with

EPA's staff, enabling EPA to gather their input; see DCNs 10–6510, 10–6518, 10–6520, 10–6521, 10–6523 and 10–6524. EPA also responded to requests for information from multiple State and local governments. EPA also attended conferences and participated in workgroups (such as NARUC's 2013 Winter Committee Meetings) where additional information about State and local government interests were presented. Historically, EPA has also conducted a great deal of outreach in developing the previous 316(b) regulations over the past decade; for example, see the Phase I final preamble (66 FR 65331, December 18, 2001), the Phase II final preamble (69 FR 41677, July 9, 2004), and the Phase III final preamble (71 FR 35037, June 16, 2006).

d. Regulatory Option Selected

EPA considered and analyzed several regulatory options to determine the best technology available for minimizing adverse environmental impact. These regulatory options are discussed in Section VI of this preamble. These options included a range of technology-based approaches, from impingement mortality technology at all facilities with a DIF of greater than 50 mgd, to requiring additional impingement mortality controls and intake flow commensurate with closed-cycle cooling for all facilities. As discussed in detail in Section VI, EPA did not select options exclusively because they are the most cost-effective among the options that fulfill the requirements of section 316(b). EPA selected the final rule because it meets the requirement of CWA section 316(b) that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts. In addition, EPA has determined that the benefits of the final rule justify the costs, taking into account quantified and qualitative benefits and costs. EPA selected a flexible approach for the final rule from among the options considered; it allows consideration of costs and benefits on a site-specific basis in determining BTA for reducing entrainment and has flexible requirements for reducing impingement mortality.

2. Impact of Compliance Requirements on Small Governments

This rule is not subject to Unfunded Mandates Reform Act section 203 requirements because it contains no regulatory requirements that could significantly or uniquely affect small governments (i.e., governments with a population of fewer than 50,000). For its assessment of the impact of compliance requirements on small governments, EPA compared the estimated total costs and costs per facility that small governments would incur with the costs that large governments would incur. EPA also compared costs for regulated facilities owned by small-government entities with costs of regulated facilities owned by non-government entities. The Agency evaluated costs per facility on the basis of both average and maximum annualized cost. The costs for facilities owned by small government entities are less than those estimated for facilities owned by large government entities, or owned by small or large non-government entities. EPA interprets these findings to indicate that the final rule will not uniquely or disproportionately affect small governments.

Because no manufacturer is government-owned, EPA conducted this analysis for electric generators only.

a. Government-Owned Electric Generators by Ownership and Entity-Size Category

Exhibit XI–7 provides an estimate of the number of non-Federal government entities that own electric generators, by ownership type and size of government entity. As presented in Exhibit XI–7, large government entities own 45 electric generators, and small government entities own 20 electric generators. Of the 65 facilities owned by government entities, 48 are owned by municipalities, six are owned by States and 11 are owned by other political subdivisions. Tribal governments own no regulated facilities.

EXHIBIT XI–7—NUMBER OF GOVERNMENT-OWNED ELECTRIC GENERATORS, BY SIZE OF GOVERNMENT [a]

Entity type	Large	Small	Total
Municipality	29	19	48
State Government	6	0	6
Other Political Subdivision	10	1	11
Tribal Government	0	0	0
Total	45	20	65

[a] Counts of explicitly and implicitly analyzed electric generators; these are not weighted estimates. For details, see EA Appendix H.

b. Compliance Costs for Electric Generators Owned by Small Government Entities

Exhibit XI–8 presents total, average annualized compliance costs, and maximum annualized compliance costs of the final rule for regulated facilities owned by government (State, local, and Tribal governments) and non-government entities by entity-size category. For the existing unit provision of the final rule, EPA estimates that small government entities will incur a total annualized cost of $2.6 million, compared to the total cost of $8.6 million incurred by large government entities and $8.5 million incurred by small private entities. On a per facility basis, EPA estimates that a facility owned by a small government entity will on average incur a cost of $0.2 million with a maximum of $0.5 million. The Agency estimates that for a facility owned by large government entity, the average cost of the existing provision of the final rule will be $0.2 million per facility with a maximum of $1.3 million, while for a facility owned by a small private entity the average cost will be $0.2 million per facility with a maximum of $1.4 million.[167] Again, overall, EPA concludes that the compliance requirements of the existing unit provision of today's rule do not significantly or uniquely affect small governments in comparison to either large governments or small private entities. For details of this analysis, see the EA Chapter 11.

EXHIBIT XI–8—ELECTRIC GENERATORS AND COMPLIANCE COSTS BY OWNERSHIP TYPE AND SIZE

[In millions, 2011 dollars]

Ownership type	Entity size	Number of facilities (weighted) [a]	Total compliance costs	Average cost per facility [d]	Maximum facility cost [e]
Final Rule:					
Government (excluding Federal)	Small	16	$2.6	$0.2	$0.5

[167] Excluding Federal government entities and regulated facilities they own.

EXHIBIT XI–8—ELECTRIC GENERATORS AND COMPLIANCE COSTS BY OWNERSHIP TYPE AND SIZE—Continued

[In millions, 2011 dollars]

Ownership type	Entity size	Number of facilities (weighted) [a]	Total compliance costs	Average cost per facility [d]	Maximum facility cost [e]
Private [b]	Large	37	8.6	0.2	1.3
	Small	53	8.5	0.2	1.4
	Large	423	184.3	0.4	5.0
All Facilities [c]		544	220	0.4	5.0

[a] Facility counts are weighted estimates and differ from the values reported in Exhibit XI–7, which are un-weighted counts and reflect information for both explicitly and implicitly analyzed electric generators. Sample-weighted values are reported in this table because costs were developed only for the explicitly analyzed electric generators. For details on development of sample weights, see EA Appendix H.

[b] Facility counts and cost estimates reported for the private sector include facilities owned by rural electric cooperatives.

[c] Facility counts and cost estimates reported for All Facilities include facilities owned by the Federal government and costs estimated for these facilities.

[d] EPA calculated average cost per facility using the total number of regulated facilities owned by entities in a given ownership category.

[e] Reflects maximum of un-weighted costs to explicitly analyzed facilities only.

3. Administrative Costs

Section 316(b) requirements are implemented through the NPDES permit program. EPA estimates that 46 States and one territory—the relevant jurisdictions with NPDES permitting authority under CWA section 402(b)—will incur costs to administer the final rule.[168] EPA estimates that States and territories will incur costs for implementing the requirements of today's rule in four activity categories: (1) Start-up activities to learn and understand the requirements of today's regulation and to implement administrative structures and procedures for administering the regulation; (2) initial permit issuance activities; (3) annual activities, including monitoring, reporting and recordkeeping; and (4) non-annually recurring permit-related activities. Exhibit XI–9 presents total annualized costs for each type of administrative activity. EPA estimates that State and local government entities will incur annualized costs of $0.9 million to administer the final rule for electric generators and manufacturers. Monitoring, reporting and recordkeeping costs compose the largest share of administrative costs.

EXHIBIT XI–9—ANNUALIZED GOVERNMENT ADMINISTRATIVE COSTS

[In millions, 2011 dollars]

Activity	Cost		Total
	Electric generators	Manufacturers	
Start-up Activities	NA	NA	[a] $0.0
Initial Permit Issuance Activities	$0.2	$0.2	0.4
Annual Monitoring, Reporting and Recordkeeping Activities	0.2	0.2	0.5
Non-Annually Recurring Permit-Related Activities [b]	[b] 0.0	0.0	0.1
Total	0.5	0.4	0.9

[a] Costs associated with start-up activities are estimated for both electric generators and manufacturers; these costs are less than $20,000.

[b] Costs are less than $50,000.

E. Executive Order 13132: Federalism

Under E.O. 13132, EPA may not issue an action that has federalism implications, that imposes substantial direct compliance costs on the State and local governments, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments, or EPA consults with State and local officials early in the process of developing the final rule.

The final rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in E.O. 13132.This final rule would not alter the basic State-Federal scheme established in the CWA under which EPA authorizes States to carry out the NPDES permitting program. Prior to this rule, authorized States were required to issue NPDES permits including requirements for CWISs on a case-by-case BPJ basis. 40 CFR 125.90(b). EPA expects that today's rule will have little to no effect on the relationship between, or the distribution of power and responsibilities among, the Federal and State governments.

EPA estimates an average annual burden of $0.9 million, for State and local governments to collectively administer the existing unit provision of the final rule.[169] The rule will also impose a compliance cost burden on State and local governments, if those government entities own facilities that are subject to today's rule. EPA has identified 554 regulated facilities that are owned by State or local government entities; the Agency estimates that under the existing unit provision of the final rule these facilities will incur an average annual compliance cost of

[168] Federal government permitting authorities will also incur costs to administer the rule. As stated earlier in this section, consistent with UMRA analysis requirements, EPA did not account for costs to Federal entities in the UMRA analysis.

[169] This estimate does not include costs to administer the new unit provision of the final rule; however, EPA expects these costs to be small.

approximately $0.2 million per facility.[170] Because this rule does not have federalism implications, the requirements of section 6 of E.O. 13132 do not apply to this rule.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have Tribal implications, as specified in E.O. 13175 (65 FR 67249, November 9, 2000). It would not have substantial direct effects on Tribal governments, on the relationship between the Federal government and the Tribes, or the distribution of power and responsibilities between the Federal government and Tribes as specified in E.O. 13175. The national cooling water intake structure standards would be implemented through permits issued under the NPDES program. No Tribal governments are authorized pursuant to CWA section 402(b) to implement the NPDES program. In addition, EPA's analyses show that Tribal governments own no facilities subject to today's rule; thus, this rule does not affect Tribes in any way now or in the foreseeable future. Thus, E.O. 13175 does not apply to this action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

This action is not subject to E.O. 13045 because it does not establish an environmental standard intended to mitigate health or safety risks. This rule establishes requirements for cooling water intake structures to protect the environment.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

E.O. 13211 (66 FR 28355, May 22, 2001) requires EPA to prepare and submit a Statement of Energy Effects to the Administrator of the Office of Information and Regulatory Affairs, Office of Management and Budget, for actions identified as *significant energy actions*. On the basis of the Office of Management and Budget's guidance for assessing the potential energy impact of regulations, the Agency anticipates that today's rule may have a significant adverse effect on the supply, distribution, or use of energy, thus requiring EPA to include a Statement of Energy Effects.

The Agency assessed the energy effects of today's rule, specifically, the rule's effect on energy supply, distribution or use in the electric power sector, as required under E.O. 13211. In its energy-effects assessment, EPA relied on Integrated Planning Model (IPM) analyses undertaken by EPA for the final rule. Based on that analysis, described in Section IX(D)(1)(d) of this preamble (Assessment of the Impacts in the Context of Electricity Markets) and in more detail in Chapter 6 of the EA report, EPA finds that the compliance requirements of the final rule may affect the electric power sector in ways that would constitute a significant adverse effect under E.O. 13211, and thus includes a Statement of Energy Effects in the economic analysis.

The Agency's analysis found that the final rule will not reduce electricity production in excess of 1 billion kWh hours per year (or one thousand GWh), will not increase the cost of energy production in excess of 1 percent, will not increase dependence on foreign supply of energy, and will not significantly affect domestic coal production. However, the final rule will result in net retirement of 998 MW of generating capacity, which exceeds 500 MW of installed capacity, the threshold of significant adverse effect identified in the OMB Implementation Guidance for E.O. 13211. EPA notes that, with only one exception, these retirements involve older, less efficient generating units with very low capacity utilization rates. The 998 MW of net retired capacity is replaced by 589 MW of new capacity; therefore, because older and less efficient capacity is replaced by new, more energy-efficient, and less polluting capacity, these retirements mean that 409 MW less capacity is needed to fulfill the same demand.

For more detail on the estimated energy effects of the final rule, see Chapter 12 of the EA, which is in the public docket.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995, Public Law 104–113, 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless doing so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. The National Technology Transfer and Advancement Act directs EPA to provide Congress, through the Office of Management and Budget, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This final rulemaking may involve technical standards, for example, in measuring impingement and entrainment. Nothing in this final rule would prevent the use of voluntary consensus standards for such measurements. EPA encourages permitting authorities and regulated entities to use voluntary consensus standards, where they are available.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

E.O. 12898 (59 FR 7629, February 16, 1994) establishes Federal executive policy on environmental justice. Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA has determined that today's rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations. Specifically, the final rule increases the level of environmental protection for all affected populations and has no high and adverse human health or environmental effects on any population, including any minority or low-income population. Because EPA expects that this final rule will help to preserve the health of aquatic ecosystems near regulated facilities, EPA expects that all populations, including minority and low-income populations, will benefit from improved environmental conditions.

To meet the objectives of E.O. 12898, EPA assessed whether today's rule could distribute benefits among population subgroups in a way that is significantly less favorable to low-income and minority populations. EPA compared key demographic characteristics of affected substate populations to those demographic characteristics at the State level. If EPA had found that the demographic profile of the substate *benefit population* is composed of a significantly lower share of low-income and/or minority populations than the State's general population, EPA might have assessed the final rule as yielding an unfavorable

[170] Cost values were calculated over the 51-year analysis period used for analysis of social costs, discounted and annualized using a rate of 7 percent (see EA Chapters 7 and 11).

distribution of benefits, from the perspective of the public policy principles of E.O. 12898. The two sets of demographic variables of interest for this environmental justice analysis are race and ethnicity, and annual household income, which are the variables in the Fish Consumption Pathway Module that best capture the minority and low-income aspects of the affected populations.[171 172] EPA compared variable averages at the substate and State levels to determine whether the demographic profile of the affected population is consistent with the State profile (for details, see EA Chapter 12).

The comparison of minority populations affected by the regulated facilities to the affected States' overall populations showed no statistically significant difference between these groups. While low-income populations constitute a lower fraction of the benefit population than of the State's overall population in many States, the two groups are not significantly different. EPA thus determined that the final rule does not systematically discriminate against, or exclude or deny participation of, the lower income population group or the minority population group in the benefits of the final rule in a way that would be contrary to the intent of E.O. 12898. Overall, EPA thus concluded that the final rule is consistent with the policy intent of E.O. 12898. Anecdotally, minority (e.g., Native American) and low-income populations might be more likely to include a larger proportion of subsistence fishermen. Because this rule will increase abundance of all fish species in the areas affected by cooling water intakes, it might provide a benefit to subsistence fishermen. To the extent that minority and low-income populations are over-represented in this group, they might especially benefit from this rule.

[171] Annual household income data in the FCP Module are available for the following categories: less than $10,000; $10,000 to $19,999; $20,000 to $24,999; $25,000 to $29,999; $30,000 to $34,999; $35,000 to $39,999; $40,000 to $49,999; $50,000 to $74,999; $75,000 to $99,999; and more than $100,000. For this analysis and previous 316(b) rule analyses, these categories were combined into low- and *not* low-income groups based on the U.S. Department of Health and Human Services' poverty guidelines for a family of four living in the contiguous United States or DC The current (2013) poverty guideline is $23,550, which falls near the upper end of the $20,000 to $24,999 income range (U.S. HHS, 2013). For the current analysis, EPA used $25,000 as the threshold for separating populations into low- and *not* low-income groups.

[172] Race and ethnic categories used in the analysis include white non-Hispanic, white Hispanic, black or African American, Asian or Native Hawaiian or Other Pacific Island, and American Indian and Alaska Native.

K. Executive Order 13158: Marine Protected Areas

E.O. 13158 (65 FR 34909, May 31, 2000) requires EPA to ''expeditiously propose new science-based regulations, as necessary, to ensure appropriate levels of protection for the marine environment.'' EPA may take action to enhance or expand protection of existing marine protected areas and to establish or recommend, as appropriate, new marine protected areas. The purpose of this executive order is to protect significant natural and cultural resources in the marine environment, which means ''those areas of coastal and ocean waters, the Great Lakes and their connecting waters, and submerged lands thereunder, over which the United States exercises jurisdiction, consistent with international law.''

Today's rule recognizes the biological sensitivity of tidal rivers, estuaries, oceans, and the Great Lakes, and their susceptibility to adverse environmental impacts from cooling water intake structures. The rule provides requirements to minimize adverse environmental impacts for cooling water intake structures on these types of waterbodies.

EPA used GIS data of the locations of MPAs (Marine Protected Areas) from the national MPA program (*http://www.mpa.gov/helpful_resources/inventory.html*) to locate regulated facilities in MPAs. Under the final rule, 60 percent of regulated facilities in MPAs obtain reductions in impingement mortality. As noted above, because of EPA's assumption that facilities with impoundments will not need to install compliance technology, this may be an underestimate. EPA cannot estimate reductions in entrainment because they would be based on site-specific determinations of BTA. Therefore, EPA expects that today's rule will advance the objective of the executive order to protect marine areas. For more details on this analysis and analysis results, see BA Chapter 8.

L. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a ''major rule'' as defined by 5 U.S.C. 804(2). This rule will be effective October 14, 2014.

List of Subjects

40 CFR Part 122

Environmental protection, Administrative practice and procedure, Confidential business information, Hazardous substances, Reporting and recordkeeping requirements, Water pollution control.

40 CFR Part 125

Environmental protection, Cooling water intake structure, Reporting and recordkeeping requirements, Waste treatment and disposal, Water pollution control.

Dated: May 19, 2014.

Gina McCarthy,

Administrator.

For reasons set out in the preamble, Chapter I of Title 40 of the Code of Federal Regulations is amended as follows:

PART 122—EPA ADMINISTERED PERMIT PROGRAMS: THE NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM

■ 1. The authority citation for part 122 continues to read as follows:

Authority: The Clean Water Act, 33 U.S.C. 1251 *et seq.*

■ 2. The suspension of 40 CFR 122.21(r)(1)(ii) and (r)(5), published on July 9, 2007 (72 FR 37109) is lifted.

■ 3. Section 122.21 is amended as follows:

■ a. Revising paragraph (r)(1).

■ b. Adding paragraphs (r)(4)(ix) through (xii).

■ c. Revising paragraph (r)(5).

■ d. Adding paragraphs (r)(6) through (14).

§ 122.21 Application for a permit (applicable to State programs, see § 123.25).

* * * * *

(r) * * *

(1) * * *

(i) *New facilities with new or modified cooling water intake structures.* New facilities (other than offshore oil and gas extraction facilities) with cooling water intake structures as defined in part 125, subpart I of this chapter, must submit to the Director for review the information required under paragraphs (r)(2) (except (r)(2)(iv)), (3), and (4) (except (r)(4)(ix), (x), (xi), and (xii)) of this section and § 125.86 of this chapter as part of the permit application. New offshore oil and gas extraction facilities with cooling water intake structures as defined in part 125, subpart N, of this chapter that are fixed facilities must submit to the Director for review the information required under paragraphs (r)(2) (except (r)(2)(iv)), (3), and (4) (except (r)(4)(ix), (x), (xi), and (xii)) of this section and § 125.136 of this chapter as part of their permit application.

(ii) *Existing facilities.* (A) *All existing facilities.* The owner or operator of an existing facility defined at 40 CFR 125.92(k) must submit to the Director for review the information required under paragraphs (r)(2) and (3) of this section and applicable provisions of paragraphs (r)(4), (5), (6), (7), and (8) of this section.

(B) *Existing facilities greater than 125 mgd AIF.* In addition, the owner or operator of an existing facility that withdraws greater than 125 mgd actual intake flow (AIF), as defined at 40 CFR 125.92 (a), of water for cooling purposes must also submit to the Director for review the information required under paragraphs (r)(9), (10), (11), (12), and (13) of this section. If the owner or operator of an existing facility intends to comply with the BTA (best technology available) standards for entrainment using a closed-cycle recirculating system as defined at 40 CFR 125.92(c), the Director may reduce or waive some or all of the information required under paragraphs (r)(9) through (13) of this section.

(C) *Additional information.* The owner or operator of an existing facility must also submit such additional information as the Director determines is necessary pursuant to 40 CFR 125.98(i).

(D) *New units at existing facilities.* The owner or operator of a new unit at an existing facility, as defined at 40 CFR 125.92(u), must submit or update any information previously provided to the Director by submitting the information required under paragraphs (r)(2), (3), (5), (8), and (14) of this section and applicable provisions of paragraphs (r)(4), (6), and (7) of this section. Requests for and approvals of alternative requirements sought under 40 CFR 125.94(e)(2) or 125.98(b)(7) must be submitted with the permit application.

(E) *New units at existing facilities not previously subject to Part 125.* The owner or operator of a new unit as defined at 40 CFR 125.92(u) at an existing facility not previously subject to part 125 of this chapter that increases the total capacity of the existing facility to more than 2 mgd DIF must submit the information required under paragraphs (r)(2), (3), (5), and (8) of this section and applicable provisions of paragraphs (r)(4), (6), and (7) of this section at the time of the permit application for the new unit. Requests for alternative requirements under 40 CFR 125.94(e)(2) or 125.98(b)(7) must be submitted with the permit application. If the total capacity of the facility will increase to more than 125 mgd AIF, the owner or operator must also submit the information required in paragraphs (r)(9) through (13) of this section. If the owner or operator of an existing facility intends to comply with the BTA (best technology available) standards for entrainment using a closed-cycle recirculating system as defined at 40 CFR 125.92(c), the Director may reduce or waive some or all of the information required under paragraphs (r)(9) through (13) of this section.

(F) If the owner or operator of an existing facility plans to retire the facility before the current permit expires, then the requirements of paragraphs (r)(1)(ii)(A), (B), (C), (D), and (E) of this section do not apply.

(G) If the owner or operator of an existing facility plans to retire the facility after the current permit expires but within one permit cycle, then the Director may waive the requirements of paragraphs (r)(7), (9), (10), (11), (12), and (13) of this section pending a signed certification statement from the owner or operator of the facility specifying the last operating date of the facility.

(H) *All facilities.* The owner or operator of any existing facility or new unit at any existing facility must also submit with its permit application all information received as a result of any communication with a Field Office of the Fish and Wildlife Service and/or Regional Office of the National Marine Fisheries Service.

* * * * *

(4) * * *

(ix) In the case of the owner or operator of an existing facility or new unit at an existing facility, the *Source Water Baseline Biological Characterization Data* is the information in paragraphs (r)(4)(i) through (xii) of this section.

(x) For the owner or operator of an existing facility, identification of protective measures and stabilization activities that have been implemented, and a description of how these measures and activities affected the baseline water condition in the vicinity of the intake.

(xi) For the owner or operator of an existing facility, a list of fragile species, as defined at 40 CFR 125.92(m), at the facility. The applicant need only identify those species not already identified as fragile at 40 CFR 125.92(m). New units at an existing facility are not required to resubmit this information if the cooling water withdrawals for the operation of the new unit are from an existing intake.

(xii) For the owner or operator of an existing facility that has obtained incidental take exemption or authorization for its cooling water intake structure(s) from the U.S. Fish and Wildlife Service or the National Marine Fisheries Service, any information submitted in order to obtain that exemption or authorization may be used to satisfy the permit application information requirement of paragraph 40 CFR 125.95(f) if included in the application.

(5) *Cooling Water System Data.* The owner or operator of an existing facility must submit the following information for each cooling water intake structure used or intended to be used:

(i) A narrative description of the operation of the cooling water system and its relationship to cooling water intake structures; the proportion of the design intake flow that is used in the system; the number of days of the year the cooling water system is in operation and seasonal changes in the operation of the system, if applicable; the proportion of design intake flow for contact cooling, non-contact cooling, and process uses; a distribution of water reuse to include cooling water reused as process water, process water reused for cooling, and the use of gray water for cooling; a description of reductions in total water withdrawals including cooling water intake flow reductions already achieved through minimized process water withdrawals; a description of any cooling water that is used in a manufacturing process either before or after it is used for cooling, including other recycled process water flows; the proportion of the source waterbody withdrawn (on a monthly basis);

(ii) Design and engineering calculations prepared by a qualified professional and supporting data to support the description required by paragraph (r)(5)(i) of this section; and

(iii) Description of existing impingement and entrainment technologies or operational measures and a summary of their performance, including but not limited to reductions in impingement mortality and entrainment due to intake location and reductions in total water withdrawals and usage.

(6) *Chosen Method(s) of Compliance with Impingement Mortality Standard.* The owner or operator of the facility must identify the chosen compliance

method for the entire facility; alternatively, the applicant must identify the chosen compliance method for each cooling water intake structure at its facility. The applicant must identify any intake structure for which a BTA determination for Impingement Mortality under 40 CFR 125.94 (c)(11) or (12) is requested. In addition, the owner or operator that chooses to comply via 40 CFR 125.94 (c)(5) or (6) must also submit an *impingement technology performance optimization study* as described below:

(i) If the applicant chooses to comply with 40 CFR 125.94(c)(5), subject to the flexibility for timing provided in 40 CFR 125.95(a)(2), the *impingement technology performance optimization study* must include two years of biological data collection measuring the reduction in impingement mortality achieved by the modified traveling screens as defined at 40 CFR 125.92(s) and demonstrating that the operation has been optimized to minimize impingement mortality. A complete description of the modified traveling screens and associated equipment must be included, including, for example, type of mesh, mesh slot size, pressure sprays and fish return mechanisms. A description of any biological data collection and data collection approach used in measuring impingement mortality must be included:

(A) Collecting data no less frequently than monthly. The Director may establish more frequent data collection;

(B) Biological data collection representative of the impingement and the impingement mortality at the intakes subject to this provision;

(C) A taxonomic identification to the lowest taxon possible of all organisms collected;

(D) The method in which naturally moribund organisms are identified and taken into account;

(E) The method in which mortality due to holding times is taken into account;

(F) If the facility entraps fish or shellfish, a count of entrapment, as defined at 40 CFR 125.92(j), as impingement mortality; and

(G) The percent impingement mortality reflecting optimized operation of the modified traveling screen and all supporting calculations.

(ii) If the applicant chooses to comply with 40 CFR 125.94(c)(6), the *impingement technology performance optimization study* must include biological data measuring the reduction in impingement mortality achieved by operation of the system of technologies, operational measures and best management practices, and demonstrating that operation of the system has been optimized to minimize impingement mortality. This system of technologies, operational measures and best management practices may include flow reductions, seasonal operation, unit closure, credit for intake location, and behavioral deterrent systems. The applicant must document how each system element contributes to the system's performance. The applicant must include a minimum of two years of biological data measuring the reduction in impingement mortality achieved by the system. The applicant must also include a description of any sampling or data collection approach used in measuring the rate of impingement, impingement mortality, or flow reductions.

(A) *Rate of Impingement.* If the demonstration relies in part on a credit for reductions in the rate of impingement in the system, the applicant must provide an estimate of those reductions to be used as credit towards reducing impingement mortality, and any relevant supporting documentation, including previously collected biological data, performance reviews, and previously conducted performance studies not already submitted to the Director. The submission of studies more than 10 years old must include an explanation of why the data are still relevant and representative of conditions at the facility and explain how the data should be interpreted using the definitions of impingement and entrapment at 40 CFR 125.92(n) and (j), respectively. The estimated reductions in rate of impingement must be based on a comparison of the system to a once-through cooling system with a traveling screen whose point of withdrawal from the surface water source is located at the shoreline of the source waterbody. For impoundments that are waters of the United States in whole or in part, the facility's rate of impingement must be measured at a location within the cooling water intake system that the Director deems appropriate. In addition, the applicant must include two years of biological data collection demonstrating the rate of impingement resulting from the system. For this demonstration, the applicant must collect data no less frequently than monthly. The Director may establish more frequent data collection.

(B) *Impingement Mortality.* If the demonstration relies in part on a credit for reductions in impingement mortality already obtained at the facility, the applicant must include two years of biological data collection demonstrating the level of impingement mortality the system is capable of achieving. The applicant must submit any relevant supporting documentation, including previously collected biological data, performance reviews, and previously conducted performance studies not already submitted to the Director. The applicant must provide a description of any sampling or data collection approach used in measuring impingement mortality. In addition, for this demonstration the applicant must:

(*1*) Collect data no less frequently than monthly. The Director may establish more frequent data collection;

(*2*) Conduct biological data collection that is representative of the impingement and the impingement mortality at an intake subject to this provision. In addition, the applicant must describe how the location of the cooling water intake structure in the waterbody and the water column are accounted for in the points of data collection;

(*3*) Include a taxonomic identification to the lowest taxon possible of all organisms to be collected;

(*4*) Describe the method in which naturally moribund organisms are identified and taken into account;

(*5*) Describe the method in which mortality due to holding times is taken into account; and

(*6*) If the facility entraps fish or shellfish, a count of the entrapment, as defined at 40 CFR 125.92(j), as impingement mortality.

(C) *Flow reduction.* If the demonstration relies in part on flow reduction to reduce impingement, the applicant must include two years of intake flows, measured daily, as part of the demonstration, and describe the extent to which flow reductions are seasonal or intermittent. The applicant must document how the flow reduction results in reduced impingement. In addition, the applicant must describe how the reduction in impingement has reduced impingement mortality.

(D) *Total system performance.* The applicant must document the percent impingement mortality reflecting optimized operation of the total system of technologies, operational measures, and best management practices and all supporting calculations. The total system performance is the combination of the impingement mortality performance reflected in paragraphs (r)(6)(ii)(A), (B), and (C) of this section.

(7) *Entrainment Performance Studies.* The owner or operator of an existing facility must submit any previously conducted studies or studies obtained from other facilities addressing technology efficacy, through-facility entrainment survival, and other

entrainment studies. Any such submittals must include a description of each study, together with underlying data, and a summary of any conclusions or results. Any studies conducted at other locations must include an explanation as to why the data from other locations are relevant and representative of conditions at your facility. In the case of studies more than 10 years old, the applicant must explain why the data are still relevant and representative of conditions at the facility and explain how the data should be interpreted using the definition of entrainment at 40 CFR 125.92(h).

(8) *Operational Status.* The owner or operator of an existing facility must submit a description of the operational status of each generating, production, or process unit that uses cooling water, including but not limited to:

(i) For power production or steam generation, descriptions of individual unit operating status including age of each unit, capacity utilization rate (or equivalent) for the previous 5 years, including any extended or unusual outages that significantly affect current data for flow, impingement, entrainment, or other factors, including identification of any operating unit with a capacity utilization rate of less than 8 percent averaged over a 24-month block contiguous period, and any major upgrades completed within the last 15 years, including but not limited to boiler replacement, condenser replacement, turbine replacement, or changes to fuel type;

(ii) Descriptions of completed, approved, or scheduled uprates and Nuclear Regulatory Commission relicensing status of each unit at nuclear facilities;

(iii) For process units at your facility that use cooling water other than for power production or steam generation, if you intend to use reductions in flow or changes in operations to meet the requirements of 40 CFR 125.94(c), descriptions of individual production processes and product lines, operating status including age of each line, seasonal operation, including any extended or unusual outages that significantly affect current data for flow, impingement, entrainment, or other factors, any major upgrades completed within the last 15 years, and plans or schedules for decommissioning or replacement of process units or production processes and product lines;

(iv) For all manufacturing facilities, descriptions of current and future production schedules; and

(v) Descriptions of plans or schedules for any new units planned within the next 5 years.

(9) *Entrainment Characterization Study.* The owner or operator of an existing facility that withdraws greater than 125 mgd AIF, where the withdrawal of cooling water is measured at a location within the cooling water intake structure that the Director deems appropriate, must develop for submission to the Director an *Entrainment Characterization Study* that includes a minimum of two years of entrainment data collection. The Entrainment Characterization Study must include the following components:

(i) *Entrainment Data Collection Method.* The study should identify and document the data collection period and frequency. The study should identify and document organisms collected to the lowest taxon possible of all life stages of fish and shellfish that are in the vicinity of the cooling water intake structure(s) and are susceptible to entrainment, including any organisms identified by the Director, and any species protected under Federal, State, or Tribal law, including threatened or endangered species with a habitat range that includes waters in the vicinity of the cooling water intake structure. Biological data collection must be representative of the entrainment at the intakes subject to this provision. The owner or operator of the facility must identify and document how the location of the cooling water intake structure in the waterbody and the water column are accounted for by the data collection locations;

(ii) *Biological Entrainment Characterization.* Characterization of all life stages of fish, shellfish, and any species protected under Federal, State, or Tribal law (including threatened or endangered species), including a description of their abundance and their temporal and spatial characteristics in the vicinity of the cooling water intake structure(s), based on sufficient data to characterize annual, seasonal, and diel variations in entrainment, including but not limited to variations related to climate and weather differences, spawning, feeding, and water column migration. This characterization may include historical data that are representative of the current operation of the facility and of biological conditions at the site. Identification of all life stages of fish and shellfish must include identification of any surrogate species used, and identification of data representing both motile and non-motile life-stages of organisms;

(iii) *Analysis and Supporting Documentation.* Documentation of the current entrainment of all life stages of fish, shellfish, and any species protected under Federal, State, or Tribal law (including threatened or endangered species). The documentation may include historical data that are representative of the current operation of the facility and of biological conditions at the site. Entrainment data to support the facility's calculations must be collected during periods of representative operational flows for the cooling water intake structure, and the flows associated with the data collection must be documented. The method used to determine latent mortality along with data for specific organism mortality or survival that is applied to other life-stages or species must be identified. The owner or operator of the facility must identify and document all assumptions and calculations used to determine the total entrainment for that facility together with all methods and quality assurance/quality control procedures for data collection and data analysis. The proposed data collection and data analysis methods must be appropriate for a quantitative survey.

(10) *Comprehensive Technical Feasibility and Cost Evaluation Study.* The owner or operator of an existing facility that withdraws greater than 125 mgd AIF must develop for submission to the Director an engineering study of the technical feasibility and incremental costs of candidate entrainment control technologies. In addition, the study must include the following:

(i) *Technical feasibility.* An evaluation of the technical feasibility of closed-cycle recirculating systems as defined at 40 CFR 125.92(c), fine mesh screens with a mesh size of 2 millimeters or smaller, and water reuse or alternate sources of cooling water. In addition, this study must include:

(A) A description of all technologies and operational measures considered (including alternative designs of closed-cycle recirculating systems such as natural draft cooling towers, mechanical draft cooling towers, hybrid designs, and compact or multi-cell arrangements);

(B) A discussion of land availability, including an evaluation of adjacent land and acres potentially available due to generating unit retirements, production unit retirements, other buildings and equipment retirements, and potential for repurposing of areas devoted to ponds, coal piles, rail yards, transmission yards, and parking lots;

(C) A discussion of available sources of process water, grey water, waste water, reclaimed water, or other waters of appropriate quantity and quality for use as some or all of the cooling water needs of the facility; and

(D) Documentation of factors other than cost that may make a candidate technology impractical or infeasible for further evaluation.

(ii) *Other entrainment control technologies.* An evaluation of additional technologies for reducing entrainment may be required by the Director.

(iii) *Cost evaluations.* The study must include engineering cost estimates of all technologies considered in paragraphs (r)(10)(i) and (ii) of this section. Facility costs must also be adjusted to estimate social costs. All costs must be presented as the net present value (NPV) and the corresponding annual value. Costs must be clearly labeled as compliance costs or social costs. The applicant must separately discuss facility level compliance costs and social costs, and provide documentation as follows:

(A) Compliance costs are calculated as after-tax, while social costs are calculated as pre-tax. Compliance costs include the facility's administrative costs, including costs of permit application, while the social cost adjustment includes the Director's administrative costs. Any outages, downtime, or other impacts to facility net revenue, are included in compliance costs, while only that portion of lost net revenue that does not accrue to other producers can be included in social costs. Social costs must also be discounted using social discount rates of 3 percent and 7 percent. Assumptions regarding depreciation schedules, tax rates, interest rates, discount rates and related assumptions must be identified;

(B) Costs and explanation of any additional facility modifications necessary to support construction and operation of technologies considered in paragraphs (r)(10)(i) and (ii) of this section, including but not limited to relocation of existing buildings or equipment, reinforcement or upgrading of existing equipment, and additional construction and operating permits. Assumptions regarding depreciation schedules, interest rates, discount rates, useful life of the technology considered, and any related assumptions must be identified; and

(C) Costs and explanation for addressing any non-water quality environmental and other impacts identified in paragraph (r)(12) of this section. The cost evaluation must include a discussion of all reasonable attempts to mitigate each of these impacts.

(11) *Benefits Valuation Study.* The owner or operator of an existing facility that withdraws greater than 125 mgd AIF must develop for submission to the Director an evaluation of the benefits of the candidate entrainment reduction technologies and operational measures evaluated in paragraph (r)(10) of this section including using the Entrainment Characterization Study completed in paragraph (r)(9) of this section. Each category of benefits must be described narratively, and when possible, benefits should be quantified in physical or biological units and monetized using appropriate economic valuation methods. The benefits valuation study must include, but is not limited to, the following elements:

(i) Incremental changes in the numbers of individual fish and shellfish lost due to impingement mortality and entrainment as defined in 40 CFR 125.92, for all life stages of each exposed species;

(ii) Description of basis for any estimates of changes in the stock sizes or harvest levels of commercial and recreational fish or shellfish species or forage fish species;

(iii) Description of basis for any monetized values assigned to changes in the stock size or harvest levels of commercial and recreational fish or shellfish species, forage fish, and to any other ecosystem or non use benefits;

(iv) A discussion of mitigation efforts completed prior to October 14, 2014 including how long they have been in effect and how effective they have been;

(v) Discussion, with quantification and monetization, where possible, of any other benefits expected to accrue to the environment and local communities, including but not limited to improvements for mammals, birds, and other organisms and aquatic habitats;

(vi) Discussion, with quantification and monetization, where possible, of any benefits expected to result from any reductions in thermal discharges from entrainment technologies.

(12) *Non-water Quality Environmental and Other Impacts Study.* The owner or operator of an existing facility that withdraws greater than 125 mgd AIF must develop for submission to the Director a detailed facility-specific discussion of the changes in non-water quality environmental and other impacts attributed to each technology and operational measure considered in paragraph (r)(10) of this section, including both impacts increased and impacts decreased. The study must include the following:

(i) Estimates of changes to energy consumption, including but not limited to auxiliary power consumption and turbine backpressure energy penalty;

(ii) Estimates of air pollutant emissions and of the human health and environmental impacts associated with such emissions;

(iii) Estimates of changes in noise;

(iv) A discussion of impacts to safety, including documentation of the potential for plumes, icing, and availability of emergency cooling water;

(v) A discussion of facility reliability, including but not limited to facility availability, production of steam, impacts to production based on process unit heating or cooling, and reliability due to cooling water availability;

(vi) Significant changes in consumption of water, including a facility-specific comparison of the evaporative losses of both once-through cooling and closed-cycle recirculating systems, and documentation of impacts attributable to changes in water consumption; and

(vii) A discussion of all reasonable attempts to mitigate each of these factors.

(13) *Peer Review.* If the applicant is required to submit studies under paragraphs (r)(10) through (12) of this section, the applicant must conduct an external peer review of each report to be submitted with the permit application. The applicant must select peer reviewers and notify the Director in advance of the peer review. The Director may disapprove of a peer reviewer or require additional peer reviewers. The Director may confer with EPA, Federal, State and Tribal fish and wildlife management agencies with responsibility for fish and wildlife potentially affected by the cooling water intake structure, independent system operators, and state public utility regulatory agencies, to determine which peer review comments must be addressed. The applicant must provide an explanation for any significant reviewer comments not accepted. Peer reviewers must have appropriate qualifications and their names and credentials must be included in the peer review report.

(14) *New Units.* The applicant must identify the chosen compliance method for the new unit. In addition, the owner or operator that selects the BTA standards for new units at 40 CFR 125.94 (e)(2) as its route to compliance must submit information to demonstrate entrainment reductions equivalent to 90 percent or greater of the reduction that could be achieved through compliance with 40 CFR 125.94(e)(1). The demonstration must include the Entrainment Characterization Study at paragraph (r)(9) of this section. In addition, if data specific to your facility indicates that compliance with the requirements of § 125.94 of this chapter for each new unit would result in compliance costs wholly out of proportion to the costs EPA considered in establishing the requirements at

issue, or would result in significant adverse impacts on local air quality, significant adverse impacts on local water resources other than impingement or entrainment, or significant adverse impacts on local energy markets, you must submit all supporting data as part of paragraph (r)(14) of this section. The Director may determine that additional data and information, including but not limited to monitoring, must be included as part of paragraph (r)(14) of this section.

PART 125—CRITERIA AND STANDARDS FOR THE NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM

■ 4. The authority citation for part 125 continues to read as follows:

Authority: The Clean Water Act, 33 U.S.C. 1251 *et seq.,* unless otherwise noted.

Subpart I—[Amended]

■ 5. Section 125.84 is amended by revising paragraphs (c) introductory text and (d)(1) to read as follows:

§ 125.84 As an owner or operator of a new facility, what must I do to comply with this subpart?

* * * * *

(c) *Track I requirements for new facilities that withdraw greater than 2 mgd and less than 10 mgd and that choose not to comply with paragraph (b) of this section.* You must comply with all the following requirements:

* * * * *

(d) * * *

(1) You must demonstrate to the Director that the technologies employed will reduce the level of adverse environmental impact from your cooling water intake structures to a level comparable to that which you would achieve were you to implement the requirements of paragraphs (b)(1) and (2) of this section. This demonstration must include a showing that the impacts to fish and shellfish, including important forage and predator species, within the watershed will be comparable to those which would result if you were to implement the requirements of paragraphs (b)(1) and (2) of this section. The Director will consider information provided by any fishery management agency and may also consider data and information from other sources.

* * * * *

■ 6. Section 125.86 is amended as follows:

■ a. Revise paragraphs (a)(1)(ii), (b)(3) introductory text, and (b)(4)(iii) introductory text.

■ b. Remove and reserve paragraphs (c)(2)(ii), (c)(2)(iv)(C), and (c)(2)(iv)(D)(*2*).

§ 125.86 As an owner or operator of a new facility, what must I collect and submit when I apply for my new or reissued NPDES permit?

(a) * * *

(1) * * *

(ii) The Track I requirements for new facilities that withdraw greater than 2 mgd and less than 10 mgd in § 125.84(c);

* * * * *

(b) * * *

(3) *Source waterbody flow information.* You must submit to the Director the following information to demonstrate that your cooling water intake structure meets the flow requirements in § 125.84(b)(3) or (c)(2).

* * * * *

(4) * * *

(iii) The owner or operator of a new facility required to install design and construction technologies and/or operational measures must develop a plan which explains the technologies and measures selected; this plan shall be based on information collected for the Source Water Biological Baseline Characterization required by 40 CFR 122.21(r)(4). Examples of appropriate technologies include, but are not limited to, wedgewire screens, fine mesh screens, fish handling and return systems, barrier nets, aquatic filter barrier systems, etc. Examples of appropriate operational measures include, but are not limited to, seasonal shutdowns or reductions in flow, and continuous operations of screens, etc. The plan must contain the following information:

* * * * *

■ 7. Section 125.87 is amended by revising paragraphs (a) introductory text and (a)(2) to read as follows:

§ 125.87 As an owner or operator of a new facility, must I perform monitoring?

* * * * *

(a) *Biological monitoring.* You must monitor both impingement and entrainment of the commercial, recreational, and forage base fish and shellfish species identified in either the Source Water Baseline Biological Characterization data required by 40 CFR 122.21(r)(4) or the Comprehensive Demonstration Study required by § 125.86(c)(2), depending on whether you chose to comply with Track I or Track II. The monitoring methods used must be consistent with those used for the Source Water Baseline Biological Characterization data required in 40 CFR 122.21(r)(4) or the Comprehensive Demonstration Study required by § 125.86(c)(2). You must follow the monitoring frequencies identified below for at least two (2) years after the initial permit issuance. After that time, the Director may approve a request for less frequent sampling in the remaining years of the permit term and when the permit is reissued, if the Director determines the supporting data show that less frequent monitoring would still allow for the detection of any seasonal and daily variations in the species and numbers of individuals that are impinged or entrained.

* * * * *

(2) *Entrainment sampling.* You must collect samples at least biweekly to monitor entrainment rates (simple enumeration) for each species over a 24-hour period during the primary period of reproduction, larval recruitment, and peak abundance identified during the Source Water Baseline Biological Characterization required by 40 CFR 122.21(r)(4) or the Comprehensive Demonstration Study required in § 125.86(c)(2). You must collect samples only when the cooling water intake structure is in operation.

* * * * *

■ 8. Section 125.89 is amended by revising paragraphs (a) introductory text and (b)(1)(i) and (ii) to read as follows:

§ 125.89 As the Director, what must I do to comply with the requirements of this subpart?

(a) *Permit application.* As the Director, you must review materials submitted by the applicant under 40 CFR 122.21(r)(4) and § 125.86 at the time of the initial permit application and before each permit renewal or reissuance.

* * * * *

(b) * * *

(1) * * *

(i) If an owner or operator of a facility chooses Track I, you must review the Design and Construction Technology Plan required in § 125.86(b)(4) to evaluate the suitability and feasibility of the technology proposed to minimize impingement mortality and entrainment of all life stages of fish and shellfish. In the first permit issued, you must put a condition requiring the facility to reduce impingement mortality and entrainment commensurate with the implementation of the technologies in the permit. Under subsequent permits, the Director must review the performance of the technologies implemented and require additional or different design and construction technologies, if needed to minimize impingement mortality and entrainment of all life stages of fish and shellfish. In addition, you must consider whether more stringent conditions are reasonably necessary in accordance with § 125.84(e).

(ii) If an owner or operator of a facility chooses Track II, you must review the information submitted with the Comprehensive Demonstration Study required in § 125.86(c)(2) and evaluate the suitability of the proposed design and construction technologies and operational measures to determine whether they will reduce both impingement mortality and entrainment of all life stages of fish and shellfish to 90 percent or greater of the reduction that could be achieved through Track I. In addition, you must review the Verification Monitoring Plan in § 125.86(c)(2)(iv)(D) and require that the proposed monitoring begin at the start of operations of the cooling water intake structure and continue for a sufficient period of time to demonstrate that the technologies and operational measures meet the requirements in § 125.84(d)(1). Under subsequent permits, the Director must review the performance of the additional and/or different technologies or measures used and determine that they reduce the level of adverse environmental impact from the cooling water intake structures to a comparable level that the facility would achieve were it to implement the requirements of § 125.84(b)(1) and (2).

* * * * *

■ 9. The suspension of 40 CFR 125.90(a), (c), and (d), and 125.91 through 125.99, published on July 9, 2007 (72 FR 37109) is lifted.

■ 10. Subpart J to part 125 is revised to read as follows:

Subpart J—Requirements Applicable to Cooling Water Intake Structures for Existing Facilities Under Section 316(b) of the Clean Water Act

Sec.

Subpart J—Requirements Applicable to Cooling Water Intake Structures for Existing Facilities Under Section 316(b) of the Clean Water Act

§ 125.90 Purpose of this subpart.

(a) This subpart establishes the section 316(b) requirements that apply to cooling water intake structures at existing facilities that are subject to this subpart. These requirements include a number of components. These include standards for minimizing adverse environmental impact associated with the use of cooling water intake structures and required procedures (e.g., permit application requirements, information submission requirements) for establishing the appropriate technology requirements at certain specified facilities as well as monitoring, reporting, and recordkeeping requirements to demonstrate compliance. In combination, these components represent the best technology available for minimizing adverse environmental impact associated with the use of cooling water intake structures at existing facilities. These requirements are to be established and implemented in National Pollutant Discharge Elimination System (NPDES) permits issued under the Clean Water Act (CWA).

(b) Cooling water intake structures not subject to requirements under §§ 125.94 through 125.99 or subparts I or N of this part must meet requirements under section 316(b) of the CWA established by the Director on a case-by-case, best professional judgment (BPJ) basis.

(c) Nothing in this subpart shall be construed to preclude or deny the right under section 510 of the CWA of any State or political subdivision of a State or any interstate agency to adopt or enforce any requirement with respect to control or abatement of pollution that is more stringent than required by Federal law.

Note to § 125.90. This regulation does not authorize take, as defined by the Endangered Species Act, 16 U.S.C. 1532(19). The U.S. Fish and Wildlife Service and National Marine Fisheries Service have determined that any impingement (including entrapment) or entrainment of Federally-listed species constitutes take. Such take may be authorized pursuant to the conditions of a permit issued under 16 U.S.C. 1539(a) or where consistent with an Incidental Take Statement contained in a Biological Opinion pursuant to 16 U.S.C. 1536(o).

§ 125.91 Applicability.

(a) The owner or operator of an existing facility, as defined in § 125.92(k), is subject to the requirements at §§ 125.94 through 125.99 if:

(1) The facility is a point source;

(2) The facility uses or proposes to use one or more cooling water intake structures with a cumulative design intake flow (DIF) of greater than 2 million gallons per day (mgd) to withdraw water from waters of the United States; and

(3) Twenty-five percent or more of the water the facility withdraws on an actual intake flow basis is used exclusively for cooling purposes.

(b) Use of a cooling water intake structure includes obtaining cooling water by any sort of contract or arrangement with one or more independent suppliers of cooling water if the independent supplier withdraws water from waters of the United States but is not itself a new or existing facility as defined in subparts I or J of this part, except as provided in paragraphs (c) and (d) of this section. An owner or operator of an existing facility may not circumvent these requirements by creating arrangements to receive cooling water from an entity that is not itself a facility subject to subparts I or J of this part.

(c) Obtaining cooling water from a public water system, using reclaimed water from wastewater treatment facilities or desalination plants, or recycling treated process wastewater effluent as cooling water does not constitute use of a cooling water intake structure for purposes of this subpart.

(d) This subpart does not apply to offshore seafood processing facilities, offshore liquefied natural gas terminals, and offshore oil and gas extraction facilities that are existing facilities as defined in § 125.92(k). The owners and operators of such facilities must meet requirements established by the Director on a case-by-case, best professional judgment (BPJ) basis.

§ 125.92 Special definitions.

In addition to the definitions provided in 40 CFR 122.2, the following special definitions apply to this subpart:

(a) *Actual Intake Flow* (AIF) means the average volume of water withdrawn on an annual basis by the cooling water intake structures over the past three years. After October 14, 2019, *Actual Intake Flow* means the average volume of water withdrawn on an annual basis by the cooling water intake structures over the previous five years. Actual intake flow is measured at a location within the *cooling water intake* *structure* that the Director deems appropriate. The calculation of actual intake flow includes days of zero flow. AIF does not include flows associated with emergency and fire suppression capacity.

(b) *All life stages of fish and shellfish* means eggs, larvae, juveniles, and adults. It does not include members of the infraclass Cirripedia in the subphylum Crustacea (barnacles), green mussels (*Perna viridis*), or zebra mussels (*Dreissena polymorpha*). The Director may determine that all life stages of fish and shellfish does not include other specified nuisance species.

(c) *Closed-cycle recirculating system* means a system designed and properly operated using minimized make-up and blowdown flows withdrawn from a water of the United States to support contact or non-contact cooling uses within a facility, or a system designed to include certain impoundments. A closed-cycle recirculating system passes cooling water through the condenser and other components of the cooling system and reuses the water for cooling multiple times.

(1) *Closed-cycle recirculating system* includes a facility with wet, dry, or hybrid cooling towers, a system of impoundments that are not waters of the United States, or any combination thereof. A properly operated and maintained closed-cycle recirculating system withdraws new source water (make-up water) only to replenish losses that have occurred due to blowdown, drift, and evaporation. If waters of the United States are withdrawn for purposes of replenishing losses to a closed-cycle recirculating system other than those due to blowdown, drift, and evaporation from the cooling system, the Director may determine a cooling system is a closed-cycle recirculating system if the facility demonstrates to the satisfaction of the Director that make-up water withdrawals attributed specifically to the cooling portion of the cooling system have been minimized.

(2) *Closed-cycle recirculating system* also includes a system with impoundments of waters of the U.S. where the impoundment was constructed prior to October 14, 2014 and created for the purpose of serving as part of the cooling water system as documented in the project purpose statement for any required Clean Water Act section 404 permit obtained to construct the impoundment. In the case of an impoundment whose construction pre-dated the CWA requirement to obtain a section 404 permit, documentation of the project's purpose must be demonstrated to the satisfaction of the Director. This documentation could be some other license or permit obtained to lawfully construct the impoundment for the purposes of a cooling water system, or other such evidence as the Director finds necessary. For impoundments constructed in uplands or not in waters of the United States, no documentation of a section 404 or other permit is required. If waters of the United States are withdrawn for purposes of replenishing losses to a closed-cycle recirculating system other than those due to blowdown, drift, and evaporation from the cooling system, the Director may determine a cooling system is a closed-cycle recirculating system if the facility demonstrates to the satisfaction of the Director that make-up water withdrawals attributed specifically to the cooling portion of the cooling system have been minimized.

(d) *Contact cooling water* means water used for cooling which comes into direct contact with any raw material, product, or byproduct. Examples of contact cooling water may include but are not limited to quench water at facilities, cooling water in a cracking unit, and cooling water directly added to food and agricultural products processing.

(e) *Cooling water* means water used for contact or non-contact cooling, including water used for equipment cooling, evaporative cooling tower makeup, and dilution of effluent heat content. The intended use of the cooling water is to absorb waste heat rejected from the process or processes used, or from auxiliary operations on the facility's premises. Cooling water obtained from a public water system, reclaimed water from wastewater treatment facilities or desalination plants, treated effluent from a manufacturing facility, or cooling water that is used in a manufacturing process either before or after it is used for cooling as process water, is not considered cooling water for the purposes of calculating the percentage of a facility's intake flow that is used for cooling purposes in § 125.91(a)(3).

(f) *Cooling water intake structure* means the total physical structure and any associated constructed waterways used to withdraw cooling water from waters of the United States. The cooling water intake structure extends from the point at which water is first withdrawn from waters of the United States up to, and including the intake pumps.

(g) *Design intake flow* (DIF) means the value assigned during the cooling water intake structure design to the maximum instantaneous rate of flow of water the cooling water intake system is capable of withdrawing from a source waterbody. The facility's DIF may be adjusted to reflect permanent changes to the maximum capabilities of the cooling water intake system to withdraw cooling water, including pumps permanently removed from service, flow limit devices, and physical limitations of the piping. DIF does not include values associated with emergency and fire suppression capacity or redundant pumps (i.e., back-up pumps).

(h) *Entrainment* means any life stages of fish and shellfish in the intake water flow entering and passing through a cooling water intake structure and into a cooling water system, including the condenser or heat exchanger. Entrainable organisms include any organisms potentially subject to *entrainment.* For purposes of this subpart, *entrainment* excludes those organisms that are collected or retained by a sieve with maximum opening dimension of 0.56 inches. Examples of sieves meeting this definition include but are not limited to a ⅜ inch square mesh, or a ½ by ¼ inch mesh. A facility must use the same mesh size when counting entrainment as is used when counting impingement.

(i) *Entrainment mortality* means death as a result of entrainment through the cooling water intake structure, or death as a result of exclusion from the cooling water intake structure by fine mesh screens or other protective devices intended to prevent the passage of entrainable organisms through the cooling water intake structure.

(j) *Entrapment* means the condition where impingeable fish and shellfish lack the means to escape the cooling water intake. *Entrapment* includes but is not limited to: Organisms caught in the bucket of a traveling screen and unable to reach a fish return; organisms caught in the forebay of a cooling water intake system without any means of being returned to the source waterbody without experiencing mortality; or cooling water intake systems where the velocities in the intake pipes or in any channels leading to the forebay prevent organisms from being able to return to the source waterbody through the intake pipe or channel.

(k) *Existing facility* means any facility that commenced construction as described in 40 CFR 122.29(b)(4) on or before January 17, 2002 (or July 17, 2006 for an offshore oil and gas extraction facility) and any modification of, or any addition of a unit at such a facility. A facility built adjacent to another facility would be a new facility while the original facility would remain as an exiting facility for purposes of this subpart. A facility cannot both be an existing facility and a new facility as defined at § 125.83.

(l) *Flow reduction* means any modification to a cooling water intake structure or its operation that serves to reduce the volume of cooling water withdrawn. Examples include, but are not limited to, variable speed pumps, seasonal flow reductions, wet cooling towers, dry cooling towers, hybrid cooling towers, unit closures, or substitution for withdrawals by reuse of effluent from a nearby facility.

(m) *Fragile species* means those species of fish and shellfish that are least likely to survive any form of impingement. For purposes of this subpart, *fragile species* are defined as those with an impingement survival rate of less than 30 percent, including but not limited to alewife, American shad, Atlantic herring, Atlantic long-finned squid, Atlantic menhaden, bay anchovy, blueback herring, bluefish, butterfish, gizzard shad, grey snapper, hickory shad, menhaden, rainbow smelt, round herring, and silver anchovy.

(n) *Impingement* means the entrapment of any life stages of fish and shellfish on the outer part of an intake structure or against a screening device during periods of intake water withdrawal. For purposes of this subpart, *impingement* includes those organisms collected or retained on a sieve with maximum distance in the opening of 0.56 inches, and excludes those organisms that pass through the sieve. Examples of sieves meeting this definition include but are not limited to a ⅜ inch square mesh, or a ½ by ¼ inch mesh. This definition is intended to prevent the conversion of entrainable organisms to counts of impingement or impingement mortality. The owner or operator of a facility must use a sieve with the same mesh size when counting entrainment as is used when counting impingement.

(o) *Impingement mortality* (IM) means death as a result of impingement. Impingement mortality also includes organisms removed from their natural ecosystem and lacking the ability to escape the cooling water intake system, and thus subject to inevitable mortality.

(p) *Independent supplier* means an entity, other than the regulated facility, that owns and operates its own cooling water intake structure and directly withdraws water from waters of the United States. The supplier provides the cooling water to other facilities for their use, but may itself also use a portion of the water. An entity that provides potable water to residential populations (e.g., public water system) is not a supplier for purposes of this subpart.

(q) *Latent mortality* means the delayed mortality of organisms that were initially alive upon being impinged or entrained but that do not survive the delayed effects of impingement and entrainment during an extended holding period. Delayed effects of impingement and entrainment include but are not limited to temperature change, physical stresses, and chemical stresses.

(r) *Minimize* means to reduce to the smallest amount, extent, or degree reasonably possible.

(s) *Modified traveling screen* means a traveling water screen that incorporates measures protective of fish and shellfish, including but not limited to: Screens with collection buckets or equivalent mechanisms designed to minimize turbulence to aquatic life; addition of a guard rail or barrier to prevent loss of fish from the collection system; replacement of screen panel materials with smooth woven mesh, drilled mesh, molded mesh, or similar materials that protect fish from descaling and other abrasive injury; continuous or near-continuous rotation of screens and operation of fish collection equipment to ensure any impinged organisms are recovered as soon as practical; a low pressure wash or gentle vacuum to remove fish prior to any high pressure spray to remove debris from the screens; and a fish handling and return system with sufficient water flow to return the fish directly to the source water in a manner that does not promote predation or re-impingement of the fish, or require a large vertical drop. The Director may approve of fish being returned to water sources other than the original source water, taking into account any recommendations from the Services with respect to endangered or threatened species. Examples of *modified traveling screens* include, but are not limited to: Modified Ristroph screens with a fish handling and return system, dual flow screens with smooth mesh, and rotary screens with fish returns or vacuum returns.

(t) *Moribund* means dying; close to death.

(u) *New unit* means a new ''stand-alone'' unit at an existing facility where construction of the new unit begins after October 14, 2014 and that does not otherwise meet the definition of a new facility at § 125.83 or is not otherwise already subject to subpart I of this part. A stand-alone unit is a separate unit that is added to a facility for either the same general industrial operation or another purpose. A new unit may have its own dedicated cooling water intake structure, or the new unit may use an existing or modified cooling water intake structure.

(v) *Offshore velocity cap* means a velocity cap located a minimum of 800 feet from the shoreline. A velocity cap is an open intake designed to change the direction of water withdrawal from vertical to horizontal, thereby creating horizontal velocity patterns that result in avoidance of the intake by fish and other aquatic organisms. For purposes of this subpart, the velocity cap must use bar screens or otherwise exclude marine mammals, sea turtles, and other large aquatic organisms.

(w) *Operational measure* means a modification to any operation that serves to minimize impact to all life stages of fish and shellfish from the cooling water intake structure. Examples of *operational measures* include, but are not limited to, more frequent rotation of traveling screens, use of a low pressure wash to remove fish prior to any high pressure spray to remove debris, maintaining adequate volume of water in a fish return, and debris minimization measures such as air sparging of intake screens and/or other measures taken to maintain the design intake velocity.

(x) *Social benefits* means the increase in social welfare that results from taking an action. Social benefits include private benefits and those benefits not taken into consideration by private decision makers in the actions they choose to take, including effects occurring in the future. Benefits valuation involves measuring the physical and biological effects on the environment from the actions taken. Benefits are generally treated one or more of three ways: A narrative containing a qualitative discussion of environmental effects, a quantified analysis expressed in physical or biological units, and a monetized benefits analysis in which dollar values are applied to quantified physical or biological units. The dollar values in a social benefits analysis are based on the principle of willingness-to-pay (WTP), which captures monetary benefits by measuring what individuals are willing to forgo in order to enjoy a particular benefit. Willingness-to-pay for nonuse values can be measured using benefits transfer or a stated preference survey.

(y) *Social costs* means costs estimated from the viewpoint of society, rather than individual stakeholders. Social cost represents the total burden imposed on the economy; it is the sum of all opportunity costs incurred associated with taking actions. These opportunity costs consist of the value lost to society of all the goods and services that will not be produced and consumed as a facility complies with permit requirements, and society reallocates resources away from other production activities and towards minimizing adverse environmental impacts.

§ 125.93 [Reserved]

§ 125.94 As an owner or operator of an existing facility, what must I do to comply with this subpart?

(a) *Applicable Best Technology Available for Minimizing Adverse Environmental Impact (BTA) standards.* (1) On or after October 14, 2014, the owner or operator of an existing facility with a cumulative design intake flow (DIF) greater than 2 mgd is subject to the BTA (best technology available) standards for impingement mortality under paragraph (c) of this section, and entrainment under paragraph (d) of this section including any measures to protect Federally-listed threatened and endangered species and designated critical habitat established under paragraph (g) of this section.

(2) Prior to *October 14, 2014,* the owner or operator of an existing facility with a cumulative design intake flow (DIF) greater than 2 mgd is subject to site-specific impingement mortality and entrainment requirements as determined by the Director on a case-by-case Best Professional Judgment basis. The Director's BTA determination may be based on consideration of some or all of the factors at § 125.98(f)(2) and (3) and the requirements of § 125.94(c). If the Director requires additional information to make the decision on what BTA requirements to include in the applicant's permit for impingement mortality and entrainment, the Director should consider whether to require any of the information at 40 CFR 122.21(r).

(3) The owner or operator of a new unit is subject to the impingement mortality and entrainment standards under paragraph (e) of this section for all cooling water intake flows used by the new unit. The remainder of the existing facility is subject to the impingement mortality standard under paragraph (c) of this section, and the entrainment standard under paragraph (d) of this section. The entire existing facility including any new units is subject to any measures to protect Federally-listed threatened and endangered species and designated critical habitat established under paragraph (g) of this section.

(b) *Compliance with BTA standards.* (1) *Aligning compliance deadlines for impingement mortality and entrainment requirements.* After issuance of a final permit that establishes the entrainment requirements under § 125.94(d), the owner or operator of an existing facility must comply with the impingement mortality standard in § 125.94(c) as soon as practicable. The Director may establish interim compliance milestones in the permit.

(2) After issuance of a final permit establishing the entrainment requirements under § 125.94(d), the owner or operator of an existing facility must comply with the entrainment standard as soon as practicable, based on a schedule of requirements established by the Director. The Director may establish interim compliance milestones in the permit.

(3) The owner or operator of a new unit at an existing facility must comply with the BTA standards at § 125.94(e) with respect to the new unit upon commencement of the new unit's operation.

(c) *BTA Standards for Impingement Mortality.* The owner or operator of an existing facility must comply with one of the alternatives in paragraphs (c)(1) through (7) of this section, except as provided in paragraphs (c)(11) or (12) of this section, when approved by the Director. In addition, a facility may also be subject to the requirements of paragraphs (c)(8), (c)(9), or (g) of this section if the Director requires such additional measures.

(1) *Closed-cycle recirculating system.* A facility must operate a closed-cycle recirculating system as defined at § 125.92(c). In addition, you must monitor the actual intake flows at a minimum frequency of daily. The monitoring must be representative of normal operating conditions, and must include measuring cooling water withdrawals, make-up water, and blow down volume. In lieu of daily intake flow monitoring, you may monitor your cycles of concentration at a minimum frequency of daily; or

(2) *0.5 Feet Per Second Through-Screen Design Velocity.* A facility must operate a cooling water intake structure that has a maximum design through-screen intake velocity of 0.5 feet per second. The owner or operator of the facility must submit information to the Director that demonstrates that the maximum design intake velocity as water passes through the structural components of a screen measured perpendicular to the screen mesh does not exceed 0.5 feet per second. The maximum velocity must be achieved under all conditions, including during minimum ambient source water surface elevations (based on BPJ using hydrological data) and during periods of maximum head loss across the screens or other devices during normal operation of the intake structure; or

(3) *0.5 Feet Per Second Through-Screen Actual Velocity.* A facility must operate a cooling water intake structure that has a maximum through-screen intake velocity of 0.5 feet per second. The owner or operator of the facility must submit information to the Director that demonstrates that the maximum intake velocity as water passes through the structural components of a screen measured perpendicular to the screen mesh does not exceed 0.5 feet per second. The maximum velocity must be achieved under all conditions, including during minimum ambient source water surface elevations (based on best professional judgment using hydrological data) and during periods of maximum head loss across the screens or other devices during normal operation of the intake structure. The Director may authorize the owner or operator of the facility to exceed the 0.5 fps velocity at an intake for brief periods for the purpose of maintaining the cooling water intake system, such as backwashing the screen face. If the intake does not have a screen, the maximum intake velocity perpendicular to the opening of the intake must not exceed 0.5 feet per second during minimum ambient source water surface elevations. In addition, you must monitor the velocity at the screen at a minimum frequency of daily. In lieu of velocity monitoring at the screen face, you may calculate the through-screen velocity using water flow, water depth, and the screen open areas; or

(4) *Existing offshore velocity cap.* A facility must operate an existing offshore velocity cap as defined at § 125.92(v) that was installed on or before October 14, 2014. Offshore velocity caps installed after October 14, 2014 must make either a demonstration under paragraph (c)(6) of this section or meet the performance standard under paragraph (c)(7) of this section. In addition, you must monitor your intake flow at a minimum frequency of daily; or

(5) *Modified traveling screens.* A facility must operate a modified traveling screen that the Director determines meets the definition at § 125.92(s) and that, after review of the information required in the *impingement technology performance optimization study* at 40 CFR 122.21(r)(6)(i), the Director determines is the best technology available for impingement reduction at the site. As the basis for the Director's determination, the owner or operator of the facility must demonstrate the technology is or will be optimized to minimize impingement mortality of all non-fragile species. The Director must include verifiable and enforceable permit conditions that ensure the

technology will perform as demonstrated; or

(6) *Systems of technologies as the BTA for impingement mortality.* A facility must operate a system of technologies, management practices, and operational measures, that, after review of the information required in the *impingement technology performance optimization study* at 40 CFR 122.21(r)(6)(ii), the Director determines is the best technology available for impingement reduction at your cooling water intake structures. As the basis for the Director's determination, the owner or operator of the facility must demonstrate the system of technology has been optimized to minimize impingement mortality of all non-fragile species. In addition, the Director's decision will be informed by comparing the impingement mortality performance data under 40 CFR 122.21(r)(6)(ii)(D) to the impingement mortality performance standard that would otherwise apply under paragraph (c)(7) of this section. The Director must include verifiable and enforceable permit conditions that ensure the system of technologies will perform as demonstrated; or

(7) *Impingement mortality performance standard.* A facility must achieve a 12-month impingement mortality performance standard of all life stages of fish and shellfish of no more than 24 percent mortality, including latent mortality, for all non-fragile species together that are collected or retained in a sieve with maximum opening dimension of 0.56 inches and kept for a holding period of 18 to 96 hours. The Director may, however, prescribe an alternative holding period. You must conduct biological monitoring at a minimum frequency of monthly to demonstrate your impingement mortality performance. Each month, you must use all of the monitoring data collected during the previous 12 months to calculate the 12-month survival percentage. The 12-month impingement mortality performance standard is the total number of fish killed divided by the total number of fish impinged over the course of the entire 12 months. The owner or operator of the facility must choose whether to demonstrate compliance with this requirement for the entire facility, or for each individual cooling water intake structure for which this paragraph (c)(7) is the selected impingement mortality requirement.

(8) *Additional measures for shellfish.* The owner or operator must comply with any additional measures, such as seasonal deployment of barrier nets, established by the Director to protect shellfish.

(9) *Additional measures for other species.* The owner or operator must comply with any additional measures, established by the Director, to protect fragile species.

(10) *Reuse of other water for cooling purposes.* This impingement mortality standard does not apply to that portion of cooling water that is process water, gray water, waste water, reclaimed water, or other waters reused as cooling water in lieu of water obtained by marine, estuarine, or freshwater intakes.

(11) *De minimis rate of impingement.* In limited circumstances, rates of impingement may be so low at a facility that additional impingement controls may not be justified. The Director, based on review of site-specific data submitted under 40 CFR 122.21(r), may conclude that the documented rate of impingement at the cooling water intake is so low that no additional controls are warranted. For threatened or endangered species, all unauthorized take is prohibited by the Endangered Species Act of 1973 (16 U.S.C. 1531 *et seq.*). Notice of a determination that no additional impingement controls are warranted must be included in the draft or proposed permit and the Director's response to all comments on this determination must be included in the record for the final permit.

(12) *Low capacity utilization power generating units.* If an existing facility has a cooling water intake structure used for one or more existing electric generating units, each with an annual average capacity utilization rate of less than 8 percent averaged over a 24-month block contiguous period, the owner or operator may request the Director consider less stringent requirements for impingement mortality for that cooling water intake structure. The Director may, based on review of site-specific data concerning cooling water system data under 40 CFR 122.21(r)(5), establish the BTA standards for impingement mortality for that cooling water intake structure that are less stringent than paragraphs (c)(1) through (7) of this section.

(d) *BTA standards for entrainment for existing facilities.* The Director must establish BTA standards for entrainment for each intake on a site-specific basis. These standards must reflect the Director's determination of the maximum reduction in entrainment warranted after consideration of the relevant factors as specified in § 125.98. The Director may also require periodic reporting on your progress towards installation and operation of site-specific entrainment controls. These reports may include updates on planning, design, and construction or other appropriate topics as required by the Director. If the Director determines that the site-specific BTA standard for entrainment under this paragraph requires performance equivalent to a closed-cycle recirculating system as defined at § 125.92(c), then under § 125.94(c)(1) your facility will comply with the impingement mortality standard for that intake.

(e) *BTA standards for impingement mortality and entrainment for new units at existing facilities.* The owner or operator of a new unit at an existing facility must achieve the impingement mortality and entrainment standards provided in either paragraph (e)(1) or (2) of this section, except as provided in paragraph (e)(4) of this section, for each cooling water intake structure used to provide cooling water to the new unit.

(1) *Requirements for new units.* The owner or operator of the facility must reduce the design intake flow for the new unit, at a minimum, to a level commensurate with that which can be attained by the use of a closed-cycle recirculating system for the same level of cooling for the new unit.

(2) *Alternative requirements for new units.* The owner or operator of a new unit at an existing facility must demonstrate to the Director that the technologies and operational measures employed will reduce the level of adverse environmental impact from any cooling water intake structure used to supply cooling water to the new unit to a comparable level to that which would be achieved under § 125.94(e)(1). This demonstration must include a showing that the entrainment reduction is equivalent to 90 percent or greater of the reduction that could be achieved through compliance with § 125.94(e)(1). In addition this demonstration must include a showing that the impacts to fish and shellfish, including important forage and predator species, within the watershed will be comparable to those which would result under the requirements of § 125.94(e)(1).

(3) This standard does not apply to:

(i) Process water, gray water, waste water, reclaimed water, or other waters reused as cooling water in lieu of water obtained by marine, estuarine, or freshwater intakes;

(ii) Cooling water used by manufacturing facilities for contact cooling purposes;

(iii) Portions of those water withdrawals for auxiliary plant cooling uses comprising less than two mgd of the facility's flow; and

(iv) Any quantity of emergency back-up water flows.

(4) The owner or operator of a facility must comply with any alternative

requirements established by the Director pursuant to § 125.98(b)(7).

(5) For cooling water flows excluded by paragraph (e)(3) of this section, the Director may establish additional BTA standards for impingement mortality and entrainment on a site-specific basis.

(f) *Nuclear facilities.* If the owner or operator of a nuclear facility demonstrates to the Director, upon the Director's consultation with the Nuclear Regulatory Commission, the Department of Energy, or the Naval Nuclear Propulsion Program, that compliance with this subpart would result in a conflict with a safety requirement established by the Commission, the Department, or the Program, the Director must make a site-specific determination of best technology available for minimizing adverse environmental impact that would not result in a conflict with the Commission's, the Department's, or the Program's safety requirement.

(g) *Additional measures to protect Federally-listed threatened and endangered species and designated critical habitat.* The Director may establish in the permit additional control measures, monitoring requirements, and reporting requirements that are designed to minimize incidental take, reduce or remove more than minor detrimental effects to Federally-listed species and designated critical habitat, or avoid jeopardizing Federally-listed species or destroying or adversely modifying designated critical habitat (e.g., prey base). Such control measures, monitoring requirements, and reporting requirements may include measures or requirements identified by an appropriate Field Office of the U.S. Fish and Wildlife Service and/or Regional Office of the National Marine Fisheries Service during the 60 day review period pursuant to § 125.98(h) or the public notice and comment period pursuant to 40 CFR 124.10. Where established in the permit by the Director, the owner or operator must implement any such requirements.

(h) *Interim BTA requirements.* An owner or operator of a facility may be subject to interim BTA requirements established by the Director in the permit on a site-specific basis.

(i) *More stringent standards.* The Director must establish more stringent requirements as best technology available for minimizing adverse environmental impact if the Director determines that compliance with the applicable requirements of this section would not meet the requirements of applicable State or Tribal law, including compliance with applicable water quality standards (including designated uses, criteria, and antidegradation requirements).

(j) The owner or operator of a facility subject to this subpart must:

(1) Submit and retain permit application and supporting information as specified in § 125.95;

(2) Conduct compliance monitoring as specified in § 125.96; and

(3) Report information and data and keep records as specified in § 125.97.

§ 125.95 Permit application and supporting information requirements.

(a) *Permit application submittal timeframe for existing facilities.* (1) The owner or operator of a facility subject to this subpart whose currently effective permit expires after July 14, 2018, must submit to the Director the information required in the applicable provisions of 40 CFR 122.21(r) when applying for a subsequent permit (consistent with the owner or operator's duty to reapply pursuant to 40 CFR 122.21(d)).

(2) The owner or operator of a facility subject to this subpart whose currently effective permit expires prior to or on July 14, 2018, may request the Director to establish an alternate schedule for the submission of the information required in 40 CFR 122.21(r) when applying for a subsequent permit (consistent with the owner or operator's duty to reapply pursuant to 40 CFR 122.21(d)). If the owner or operator of the facility demonstrates that it could not develop the required information by the applicable date for submission, the Director must establish an alternate schedule for submission of the required information.

(3) The Director may waive some or all of the information requirements of 40 CFR 122.21(r) if the intake is located in a manmade lake or reservoir and the fisheries are stocked and managed by a State or Federal natural resources agency or the equivalent. If the manmade lake or reservoir contains Federally-listed threatened and endangered species, or is designated critical habitat, such a waiver shall not be granted.

(b) *Permit application submittal timeframe for new units.* For the owner or operator of any new unit at an existing facility subject to this subpart:

(1) You must submit the information required in 40 CFR 122.21(r) for the new unit to the Director no later than 180 days before the planned commencement of cooling water withdrawals for the operation of the new unit. If you have already submitted the required information in your previous permit application, you may choose to submit an update to the required information.

(2) The owner or operator is encouraged to submit their permit applications well in advance of the 180 day requirement to avoid delay.

(c) *Permit applications.* After the initial submission of the 40 CFR 122.21(r) permit application studies after October 14, 2014, the owner or operator of a facility may, in subsequent permit applications, request to reduce the information required, if conditions at the facility and in the waterbody remain substantially unchanged since the previous application so long as the relevant previously submitted information remains representative of current source water, intake structure, cooling water system, and operating conditions. Any habitat designated as critical or species listed as threatened or endangered after issuance of the current permit whose range of habitat or designated critical habit includes waters where a facility intake is located constitutes potential for a substantial change that must be addressed by the owner/operator in subsequent permit applications, unless the facility received an exemption pursuant to 16 U.S.C. 1536(o) or a permit pursuant to 16 U.S.C. 1539(a) or there is no reasonable expectation of take. The owner or operator of a facility must submit its request for reduced cooling water intake structure and waterbody application information to the Director at least two years and six months prior to the expiration of its NPDES permit. The owner or operator's request must identify each element in this subsection that it determines has not substantially changed since the previous permit application and the basis for the determination. The Director has the discretion to accept or reject any part of the request.

(d) The Director has the discretion to request additional information to supplement the permit application, including a request to inspect a facility.

(e) *Permit application records.* The owner or operator of a facility must keep records of all submissions that are part of its permit application until the subsequent permit is issued to document compliance with the requirements of this section. If the Director approves a request for reduced permit application studies under § 125.95(a) or (c) or § 125.98(g), the owner or operator of a facility must keep records of all submissions that are part of the previous permit application until the subsequent permit is issued.

(f) In addition, in developing its permit application, the owner or operator of an existing facility or new unit at an existing facility must, based on readily available information at the time of the permit application, instead of the information required at § 122.21(r)(4)(vi) of this chapter identify all Federally-listed threatened and endangered species and/or designated critical habitat that are or may be present in the action area.

(g) *Certification.* The owner or operator of a facility must certify that its permit application is true, accurate and complete pursuant to § 122.22(d) of this chapter.

§ 125.96 Monitoring requirements.

(a) *Monitoring requirements for impingement mortality for existing facilities.* The Director may establish monitoring requirements in addition to those specified at § 125.94(c), including, for example, biological monitoring, intake velocity and flow measurements. If the Director establishes such monitoring, the specific protocols will be determined by the Director.

(b) *Monitoring requirements for entrainment for existing facilities.* Monitoring requirements for entrainment will be determined by the Director on a site-specific basis, as appropriate, to meet requirements under § 125.94(d).

(c) *Additional monitoring requirements for existing facilities.* The Director may require additional monitoring for impingement or entrainment including, but not limited to, the following:

(1) The Director may require additional monitoring if there are changes in operating conditions at the facility or in the source waterbody that warrant a re-examination of the operational conditions identified at 40 CFR 122.21(r).

(2) The Director may require additional monitoring for species not subject to the BTA requirements for impingement mortality at § 125.95(c). Such monitoring requirements will be determined by the Director on a site-specific basis.

(d) *Monitoring requirements for new units at existing facilities.* Monitoring is required to demonstrate compliance with the requirements of § 125.94(e).

(1) The Director may establish monitoring requirements for impingement, impingement mortality, and entrainment of the commercial, recreational, and forage base fish and shellfish species identified in the Source Water Baseline Biological Characterization data required by 40 CFR 122.21(r)(4). Monitoring methods used must be consistent with those used for the Source Water Baseline Biological Characterization at 40 CFR 122.21(r)(4). If the Director establishes such monitoring requirements, the frequency of monitoring and specific protocols will be determined by the Director.

(2) If your facility is subject to the requirements of § 125.94(e)(1) or (2), the frequency of flow monitoring and velocity monitoring must be daily and must be representative of normal operating conditions. Flow monitoring must include measuring cooling water withdrawals, make-up water, and blowdown volume. The Director may require additional monitoring necessary to demonstrate compliance with § 125.94(e).

(3) If your facility is subject to the requirements of § 125.94(e)(2), you must monitor to demonstrate achievement of reductions commensurate with a closed-cycle recirculating system. You must monitor entrainable organisms at a proximity to the intake that is representative of the entrainable organisms in the absence of the intake structure. You must also monitor the latent entrainment mortality in front of the intake structure. Mortality after passing the cooling water intake structure must be counted as 100 percent mortality unless you have demonstrated to the approval of the Director that the mortality for each species is less than 100 percent. Monitoring must be representative of the cooling water intake when the structure is in operation. In addition, sufficient samples must be collected to allow for calculation of annual average entrainment levels of all life stages of fish and shellfish. Specific monitoring protocols and frequency of monitoring will be determined by the Director. You must follow the monitoring frequencies identified by the Director for at least two years after the initial permit issuance. After that time, the Director may approve a request for less frequent monitoring in the remaining years of the permit term and when a subsequent permit is reissued. The monitoring must measure the total count of entrainable organisms or density of organisms, unless the Director approves of a different metric for such measurements. In addition, you must monitor the AIF for each intake. The AIF must be measured at the same time as the samples of entrainable organisms are collected. The Director may require additional monitoring necessary to demonstrate compliance with § 125.94(e).

(4) The Director may require additional monitoring for impingement or entrainment at the cooling water intake structure used by a new unit including, but not limited to, the following:

(i) The Director may require additional monitoring if there are changes in operating conditions at the facility or in the source waterbody that warrant a re-examination of the operational conditions identified at 40 CFR 122.21(r).

(ii) The Director may require additional monitoring for species not subject to the BTA requirements for impingement mortality at § 125.95(c). Such monitoring requirements will be determined by the Director on a site-specific basis.

(e) *Visual or remote inspections.* You must either conduct visual inspections or employ remote monitoring devices during the period the cooling water intake structure is in operation. You must conduct such inspections at least weekly to ensure that any technologies operated to comply with § 125.94 are maintained and operated to function as designed including those installed to protect Federally-listed threatened or endangered species or designated critical habitat. The Director may establish alternative procedures if this requirement is not feasible (e.g., an offshore intake, velocity cap, or during periods of inclement weather).

(f) *Request for reduced monitoring.* For facilities that are subject to § 125.94(c)(7) and where the facility's cooling water intake structure does not directly or indirectly affect Federally-listed threatened and endangered species, or designated critical habitat, the owner or operator of the facility may request the Director to reduce monitoring requirements after the first full permit term in which these monitoring requirements are implemented, on the condition that the results of the monitoring to date demonstrate that the owner or operator of the facility has consistently operated the intake as designed and is meeting the requirements of § 125.94(c).

(g) *Additional monitoring related to Federally-listed threatened and endangered species and designated critical habitat at existing facilities.* Where the Director requires additional measures to protect Federally-listed threatened or endangered species or designated critical habitat pursuant to § 125.94(g), the Director shall require monitoring associated with those measures.

§ 125.97 Other permit reporting and recordkeeping requirements.

The owner or operator of an existing facility subject to this subpart is required to submit to the Director the following information:

(a) *Monitoring reports.* Discharge Monitoring Reports (DMRs) (or equivalent State reports) and results of all monitoring, demonstrations, and other information required by the permit sufficient to determine compliance with the permit conditions and requirements established under § 125.94.

(b) *Status reports.* Any reports required by the Director under § 125.94.

(c) *Annual certification statement and report.* An annual certification statement signed by the responsible corporate officer as defined in § 122.22 of this chapter subject to the following:

(1) If the information contained in the previous year's annual certification is still pertinent, you may simply state as such in a letter to the Director and the letter, along with any applicable data submission requirements specified in this section shall constitute the annual certification.

(2) If you have substantially modified operation of any unit at your facility that impacts cooling water withdrawals or operation of your cooling water intake structures, you must provide a summary of those changes in the report. In addition, you must submit revisions to the information required at § 122.21(r) of this chapter in your next permit application.

(d) *Permit reporting records retention.* Records of all submissions that are part of the permit reporting requirements of this section must be retained until the subsequent permit is issued. In addition, the Director may require supplemental recordkeeping such as compliance monitoring under § 125.96, supplemental data collection under 40 CFR 122.21, additional monitoring or data collection under § 125.95.

(e) *Reporting.* The Director has the discretion to require additional reporting when necessary to establish permit compliance and may provide for periodic inspection of the facility. The Director may require additional reporting including but not limited to the records required under § 125.97(d).

(f) *Records of Director's Determination of BTA for Entrainment.* All records supporting the Director's Determination of BTA for Entrainment under § 125.98(f) or (g) must be retained until such time as the Director revises the Determination of BTA for Entrainment in the permit.

(g) *Additional reporting requirements related to Federally-listed threatened and endangered species or designated critical habitat.* Where the Director requires additional measures to protect Federally-listed threatened or endangered species or critical habitat pursuant to § 125.94(g), the Director shall require reporting associated with those measures.

§ 125.98 Director requirements.

(a) *Permit application.* The Director must review the materials submitted by the applicant under 40 CFR 122.21(r) for completeness pursuant to 40 CFR 122.21(e) at the time of initial permit application and any application for a subsequent permit.

(b) *Permitting requirements.* Section 316(b) requirements are implemented through an NPDES permit. Based on the information submitted in the permit application, the Director must determine the requirements and conditions to include in the permit.

(1) Such permits, including permits with alternative requirements under paragraph (b)(7) of this section, must include the following language as a permit condition: ''Nothing in this permit authorizes take for the purposes of a facility's compliance with the Endangered Species Act.''

(2) In the case of any permit issued after July 14, 2018, at a minimum, the permit must include conditions to implement and ensure compliance with the impingement mortality standard at § 125.94(c) and the entrainment standard at § 125.94(d), including any measures to protect Federally-listed threatened and endangered species and designated critical habitat required by the Director. In addition, the permit must include conditions, management practices and operational measures necessary to ensure proper operation of any technology used to comply with the impingement mortality standard at § 125.94(c) and the entrainment standard at § 125.94(d). Pursuant to § 125.94(g), the permit may include additional control measures, monitoring requirements, and reporting requirements that are designed to minimize incidental take, reduce or remove more than minor detrimental effects to Federally-listed species and designated critical habitat, or avoid jeopardizing Federally-listed species or destroying or adversely modifying designated critical habitat (e.g. prey base). Such control measures, monitoring requirements, and reporting requirements may include measures or requirements identified by the U.S. Fish and Wildlife Service and/or the National Marine Fisheries Service during the 60 day review period pursuant to § 125.98(h) or the public notice and comment period pursuant to 40 CFR 124.10. The Director may include additional permit requirements if:

(i) Based on information submitted to the Director by any fishery management agency or other relevant information, there are migratory or sport or commercial species subject to entrainment that may be directly or indirectly affected by the cooling water intake structure; or

(ii) It is determined by the Director, based on information submitted by any fishery management agencies or other relevant information, that operation of the facility, after meeting the entrainment standard of this section, would still result in undesirable cumulative stressors to Federally-listed and proposed, threatened and endangered species, and designated and proposed critical habitat.

(3) At a minimum, the permit must require the permittee to monitor as required at §§ 125.94 and 125.96.

(4) At a minimum, the permit must require the permittee to report and keep the records specified at § 125.97.

(5) After October 14, 2014, in the case of any permit issued before July 14, 2018 for which the Director, pursuant to § 125.95(a)(2), has established an alternate schedule for submission of the information required by 40 CFR 122.21(r), the Director may include permit conditions to ensure that, for any subsequent permit, the Director will have all the information required by 40 CFR 122.21(r) necessary to establish impingement mortality and entrainment BTA requirements under § 125.94(c) and (d). In addition, the Director must establish interim BTA requirements in the permit based on the Director's best professional judgment on a site-specific basis in accordance with § 125.90(b) and 40 CFR 401.14.

(6) In the case of any permit issued after October 14, 2014, and applied for before October 14, 2014, the Director may include permit conditions to ensure that the Director will have all the information under 40 CFR 122.21(r) necessary to establish impingement mortality and entrainment BTA requirements under § 125.94(c) and (d) for the subsequent permit. The Director must establish interim BTA requirements in the permit on a site-specific basis based on the Director's best professional judgment in accordance with § 125.90(b) and 40 CFR 401.14.

(7) For new units at existing facilities, the Director may establish alternative requirements if the data specific to the facility indicate that compliance with the requirements of § 125.94(e)(1) or (2) for each new unit would result in compliance costs wholly out of proportion to the costs EPA considered in establishing the requirements at issue, or would result in significant adverse impacts on local air quality, significant adverse impacts on local water resources other than impingement

or entrainment, or significant adverse impacts on local energy markets:

(i) The alternative requirements must achieve a level of performance as close as practicable to the requirements of § 125.94(e)(1);

(ii) The alternative requirements must ensure compliance with these regulations, other provisions of the Clean Water Act, and State and Tribal law;

(iii) The burden is on the owner or operator of the facility requesting the alternative requirement to demonstrate that alternative requirements should be authorized for the new unit.

(8) The Director may require additional measures such as seasonal deployment of barrier nets, to protect shellfish.

(c) *Compliance schedule.* When the Director establishes a schedule of requirements under § 125.94(b), the schedule must provide for compliance with § 125.94(c) and (d) as soon as practicable. When establishing a schedule for electric power generating facilities, the Director should consider measures to maintain adequate energy reliability and necessary grid reserve capacity during any facility outage. These may include establishing a staggered schedule for multiple facilities serving the same localities. The Director may confer with independent system operators and state public utility regulatory agencies when establishing a schedule for electric power generating facilities. The Director may determine that extenuating circumstances (e.g., lengthy scheduled outages, future production schedules) warrant establishing a different compliance date for any manufacturing facility.

(d) *Supplemental Technologies and Monitoring.* The Director may require additional technologies for protection of fragile species, and may require additional monitoring of species of fish and shellfish not already required under § 125.95(c). The Director may consider data submitted by other interested parties. The Director may also require additional study and monitoring if a threatened or endangered species has been identified in the vicinity of the intake.

(e) *Impingement technology performance optimization study.* The owner or operator of a facility that chooses to comply with § 125.94(c)(5) or (6) must demonstrate in its *impingement technology performance optimization study* that the operation of its impingement reduction technology has been optimized to minimize impingement mortality of non-fragile species. The Director may request further data collection and information as part of the *impingement technology performance optimization study,* including extending the study period beyond two years. The Director may also consider previously collected biological data and performance reviews as part of the study. The Director must include in the permit verifiable and enforceable permit conditions that ensure the modified traveling screens or other systems of technologies will perform as demonstrated. The Director may waive all or part of the *impingement technology performance optimization study* at 40 CFR122.21(r)(6) after the first permit cycle wherein the permittee is deemed in compliance with § 125.94(c).

(f) *Site-specific entrainment requirements.* The Director must establish site-specific requirements for entrainment after reviewing the information submitted under 40 CFR 122.21(r) and § 125.95. These entrainment requirements must reflect the Director's determination of the maximum reduction in entrainment warranted after consideration of factors relevant for determining the best technology available for minimizing adverse environmental impact at each facility. These entrainment requirements may also reflect any control measures to reduce entrainment of Federally-listed threatened and endangered species and designated critical habitat (e.g. prey base). The Director may reject an otherwise available technology as a basis for entrainment requirements if the Director determines there are unacceptable adverse impacts including impingement, entrainment, or other adverse effects to Federally-listed threatened or endangered species or designated critical habitat. Prior to any permit reissuance after July 14, 2018, the Director must review the performance of the facility's installed entrainment technology to determine whether it continues to meet the requirements of § 125.94(d).

(1) The Director must provide a written explanation of the proposed entrainment determination in the fact sheet or statement of basis for the proposed permit under 40 CFR 124.7 or 124.8. The written explanation must describe why the Director has rejected any entrainment control technologies or measures that perform better than the selected technologies or measures, and must reflect consideration of all reasonable attempts to mitigate any adverse impacts of otherwise available better performing entrainment technologies.

(2) The proposed determination in the fact sheet or statement of basis must be based on consideration of any additional information required by the Director at § 125.98(i) and the following factors listed below. The weight given to each factor is within the Director's discretion based upon the circumstances of each facility.

(i) Numbers and types of organisms entrained, including, specifically, the numbers and species (or lowest taxonomic classification possible) of Federally-listed, threatened and endangered species, and designated critical habitat (e.g., prey base);

(ii) Impact of changes in particulate emissions or other pollutants associated with entrainment technologies;

(iii) Land availability inasmuch as it relates to the feasibility of entrainment technology;

(iv) Remaining useful plant life; and

(v) Quantified and qualitative social benefits and costs of available entrainment technologies when such information on both benefits and costs is of sufficient rigor to make a decision.

(3) The proposed determination in the fact sheet or statement of basis may be based on consideration of the following factors to the extent the applicant submitted information under 40 CFR 122.21(r) on these factors:

(i) Entrainment impacts on the waterbody;

(ii) Thermal discharge impacts;

(iii) Credit for reductions in flow associated with the retirement of units occurring within the ten years preceding October 14, 2014;

(iv) Impacts on the reliability of energy delivery within the immediate area;

(v) Impacts on water consumption; and

(vi) Availability of process water, gray water, waste water, reclaimed water, or other waters of appropriate quantity and quality for reuse as cooling water.

(4) If all technologies considered have social costs not justified by the social benefits, or have unacceptable adverse impacts that cannot be mitigated, the Director may determine that no additional control requirements are necessary beyond what the facility is already doing. The Director may reject an otherwise available technology as a BTA standard for entrainment if the social costs are not justified by the social benefits.

(g) *Ongoing permitting proceedings.* In the case of permit proceedings begun prior to October 14, 2014 whenever the Director has determined that the information already submitted by the owner or operator of the facility is sufficient, the Director may proceed with a determination of BTA standards for impingement mortality and entrainment without requiring the owner or operator of the facility to submit the information required in 40 CFR 122.21(r). The Director's BTA determination may be based on some or all of the factors in paragraphs (f)(2) and (3) of this section and the BTA standards for impingement mortality at § 125.95(c). In making the decision on whether to require additional information from the applicant, and what BTA requirements to include in the applicant's permit for impingement mortality and site-specific entrainment, the Director should consider whether any of the information at 40 CFR 122.21(r) is necessary.

(h) The Director must transmit all permit applications for facilities subject to this subpart to the appropriate Field Office of the U.S. Fish and Wildlife Service and/or Regional Office of the National Marine Fisheries Service upon receipt for a 60 day review prior to public notice of the draft or proposed permit. The Director shall provide the public notice and an opportunity to comment as required under 40 CFR 124.10 and must submit a copy of the fact sheet or statement of basis (for EPA-issued permits), the permit application (if any) and the draft permit (if any) to the appropriate Field Office of the. Fish and Wildlife Service and/or Regional Office of the National Marine Fisheries Service. This includes notice of specific cooling water intake structure requirements at § 124.10(d)(1)(ix) of this chapter, notice of the draft permit, and any specific information the Director has about threatened or endangered species and critical habitat that are or may be present in the action area, including any proposed control measures and monitoring and reporting requirements for such species and habitat.

(i) *Additional information.* In implementing the Director's responsibilities under the provisions of this subpart, the Director is authorized to inspect the facility and to request additional information needed by the Director for determining permit conditions and requirements, including any additional information from the facility recommended by the Services upon review of the permit application under paragraph (h) of this section.

(j) Nothing in this subpart authorizes the take, as defined at 16 U.S.C. 1532(19), of threatened or endangered species of fish or wildlife. Such take is prohibited under the Endangered Species Act unless it is exempted pursuant to 16 U.S.C. 1536(o) or permitted pursuant to 16 U.S.C. 1539(a). Absent such exemption or permit, any facility operating under the authority of this regulation must not take threatened or endangered wildlife.

(k) The Director must submit at least annually to the appropriate EPA Regional Office facilities' annual reports submitted pursuant to § 125.97(g), for compilation and transmittal to the Services.

§ 125.99 [Reserved]

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BILLING CODE 6560–50–P

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

ENVIRONMENTAL COST RECOVERY CLAUSE

DOCKET NO. 20180007-EI

PREPARED DIRECT TESTIMONY
AND EXHIBIT OF
C. SHANE BOYETT

PROJECTION FILING
FOR THE PERIOD

JANUARY 2019- DECEMBER 2019

August 24, 2018

Gulf Power

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
C. Shane Boyett
Docket No. 20180007-EI
Date of Filing: August 24, 2018

Q. Please state your name, business address and occupation.
A. My name is Shane Boyett. My business address is One Energy Place, Pensacola, Florida 32520. I am the Regulatory and Cost Recovery Manager for Gulf Power Company.

Q. Have you previously filed testimony in this docket?
A. Yes.

Q. What is the purpose of your testimony?
A. The purpose of my testimony is to present both the calculation of the revenue requirements and the development of the environmental cost recovery factors for the period January 2019 through December 2019.

Q. Have you prepared any exhibits that contain information to which you will refer in your testimony?
A. Yes, I am sponsoring one exhibit. My exhibit consists of ten schedules, nine of which are Gulf's environmental cost recovery projection schedules and one of which contains the calculation of the Scherer/Flint credit. This exhibit was prepared under my direction, supervision, or review.

Counsel: We ask that Mr. Boyett's exhibit be marked as Exhibit No. _____(CSB-3).

Q. What environmental costs is Gulf requesting recovery of through the Environmental Cost Recovery Clause (ECRC)?

A. As discussed in the testimony of Gulf Witness Richard M. Markey, Gulf is requesting recovery for certain environmental compliance operating expenses and capital costs that are consistent with both the decision of the Florida Public Service Commission (FPSC or Commission) in Order No. PSC-94-0044-FOF-EI in Docket No. 930613-EI and with past proceedings in this ongoing recovery docket. The costs identified for recovery through the ECRC are not currently being recovered through base rates or any other cost recovery mechanism.

Q. How was the amount of projected Operations and Maintenance (O&M) expenses to be recovered through the ECRC calculated?

A. Mr. Markey has provided projected recoverable O&M expenses for January 2019 through December 2019. Schedule 2P of Exhibit CSB-3 shows the calculation of the recoverable O&M expenses broken down between demand-related and energy-related expenses. Schedule 2P also provides the appropriate jurisdictional factors and amounts related to these expenses. All O&M expenses associated with compliance with air quality environmental regulations were considered to be energy-related, consistent with Commission Order No. PSC-94-0044-FOF-EI. The remaining expenses were broken down between demand and energy consistent with Gulf's last approved cost-of-service methodology.

Q. Please describe Schedules 3P and 4P of your Exhibit CSB-3.

A. Schedule 3P summarizes the monthly recoverable revenue requirements associated with each capital investment program for the recovery period. Schedule 4P shows the detailed calculation of the revenue requirements associated with each investment program. Schedules 3P and 4P also include the calculation of the jurisdictional amount of recoverable revenue requirements. To prepare these schedules, Mr. Markey provided the expenditures, clearings, retirements, salvage, and cost of removal related to each capital project, as well as the monthly costs for emission allowances. From that information, plant-in-service and construction work in progress (non-interest bearing) was calculated. Additionally, depreciation, amortization and dismantlement expense and the associated accumulated depreciation balances, were calculated based on Gulf's approved depreciation rates, amortization periods, and dismantlement accruals. The capital projects identified for recovery through the ECRC are those environmental projects which were not included in the test year on which present base rates were set.

Q. How was the amount of property taxes to be recovered through the ECRC derived?

A. Property taxes were calculated by applying the projected applicable millage rate to the ECRC apportioned assessed value.

Q. What capital structure and return on equity were used to develop the rate of return used to calculate the revenue requirements as shown on 8P?

A. The capital structure used in calculating the rate of return for recovery clause purposes is based on the weighted average cost of capital (WACC) presented in Gulf's May 2018 Surveillance Report, as adjusted per the terms of the 2018 Tax Settlement and Stipulation Agreement, approved by FPSC Order No. PSC-2018-0180-FOF-EI in Docket No. 20180039-EI, dated April 12, 2018. The rate of return used to calculate ECRC revenue requirements includes a return on equity of 10.25 percent for the period January 1, 2019, through December 31, 2019, a federal income tax rate of 21 percent and is consistent with Commission Order No. PSC-12-0425-PAA-EU dated August 16, 2012, in Docket No. 120007-EI.

Q. How has the breakdown between demand-related and energy-related investment costs been determined?

A. Consistent with Commission Order No. PSC-13-0606-FOF-EI dated November 19, 2013, in Docket No. 130007-EI, investment costs recoverable through ECRC were broken down within the retail jurisdiction based on the 12-MCP and $1/13^{th}$ energy allocator. The use of this allocator is consistent with cost-of-service studies approved in Gulf's prior base rate cases. The calculation of this breakdown is shown on Schedule 4P and summarized on Schedule 3P.

Q. What is the total amount of projected recoverable costs related to the period January 2019 through December 2019?

A. The total projected jurisdictional recoverable costs for the period January 2019 through December 2019 is $184,156,532 as shown on line 1c of Schedule 1P of Exhibit CSB-3. This amount includes costs related to O&M activities of $32,665,945 and costs related to capital projects of $151,490,587, as shown on lines 1a and 1b of Schedule 1P. The adjustment (Scherer/Flint credit) as reflected on Lines 1.29 and 1.30 of Schedule 2P and Lines 1.36 and 1.37 of Schedule 3P represents the incremental revenue requirement related to the portion of Scherer Unit 3 (Scherer 3) that continues to be committed to a wholesale customer through a long-term contact. The Scherer/Flint credit is calculated in accordance with the provisions in the Stipulation and Settlement Agreement, FPSC Order No. PSC-17-0178-S-EI, resulting in ECRC being revenue-neutral regarding the incremental inclusion of Scherer 3 investment and expenses.

Q. What is the total recoverable revenue requirement to be recovered in the projection period January 2019 through December 2019, and how was it allocated to each rate class?

A. The total recoverable revenue requirement including revenue taxes is $171,663,438 for the period January 2019 through December 2019, as shown on line 5 of Schedule 1P of Exhibit CSB-3. This amount includes the recoverable costs related to the projection period offset by the total over-recovery true-up amount of $12,616,603. Schedule 1P also summarizes the energy and demand components of the requested revenue requirement. These amounts are allocated by rate class using the appropriate energy and demand allocators as shown on Schedule 6P and 7P of Exhibit CSB-3.

Q. How were the rate class allocation factors calculated for use in the Environmental Cost Recovery Clause?

A. The demand allocation factors used in the ECRC have been calculated using the 2015 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C. and adjusted for losses. The energy allocation factors were calculated based on projected kWh sales for the period adjusted for losses. The calculation of the allocation factors for the period is shown in columns A through G on Schedule 6P of Exhibit CSB-3.

Q. How were these factors applied to allocate the requested recovery amount properly to the rate classes?

A. As I described earlier in my testimony, Schedule 1P of Exhibit CSB-3 summarizes the energy and demand portions of the total requested revenue requirement. The energy-related recoverable revenue requirement of $32,401,985 for the period January 2019 through December 2019 was allocated using the energy allocator, as shown in column C on Schedule 7P of Exhibit CSB-3. The demand-related recoverable revenue requirement of $139,261,453 for the period January 2019 through December 2019 was allocated using the demand allocator, as shown in column D on Schedule 7P. The energy-related and demand-related recoverable revenue requirements are added together to derive the total amount assigned to each rate class, as shown in column E on Schedule 7P.

Q. What is the monthly amount related to environmental costs recovered through this factor that will be included on a residential customer's bill for 1,000 kWh?

A. The environmental costs recovered through the clause from the residential customer who uses 1,000 kWh will be $18.10 monthly for the period January 2019 through December 2019.

Q. When does Gulf propose to collect its environmental cost recovery charges?

A. The factors will be effective beginning with Cycle 1 billings in January 2019 and will continue through the last billing cycle of December 2019.

Q. Mr. Boyett, does this conclude your testimony?

A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 20180007-EI

Before me, the undersigned authority, personally appeared C. Shane Boyett, who being first duly sworn, deposes and says that he is the Regulatory and Cost Recovery Manager of Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of his knowledge and belief. He is personally known to me.

C. Shane Boyett

C. Shane Boyett
Regulatory and Cost Recovery Manager

Sworn to and subscribed before me this 24th day of August, 2018.

Melissa Darnes

Notary Public, State of Florida at Large

NOTARY PUBLIC STATE OF FLORIDA
MELISSA DARNES
MY COMMISSION # FF 912698
EXPIRES: December 17, 2019
Bonded Thru Budget Notary Services

Schedule 1P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to be Recovered

For the Projected Period
January 2019 - December 2019

Line No.			Energy ($)	Demand ($)	Total ($)
1	Total Jurisdictional Rev. Req. for the projected period				
	a	Projected O & M Activities (Schedule 2P, Lines 7, 8 & 9)	23,101,020	9,564,925	32,665,945
	b	Projected Capital Projects (Schedule 3P, Lines 7, 8 & 9)	11,674,807	139,815,780	151,490,587
	c	Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	34,775,827	149,380,705	184,156,532
2	True-Up for Estimated Over/(Under) Recovery for the period January 2018 - December 2018 (Schedule 1E, Line 3)		1,793,018	7,643,919	9,436,937
3	Final True-Up for the period January 2017 - December 2017 (Schedule 1A, Line 3)		604,137	2,575,529	3,179,666
4	Total Jurisdictional Amount to be Recovered/(Refunded) in the projection period January 2019 - December 2019 (Line 1c - Line 2 - Line 3)		32,378,672	139,161,257	171,539,929
5	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier)		32,401,985	139,261,453	171,663,438

Notes:

Allocation to energy and demand in each period are in proportion to the respective period split of costs indicated on Lines 7 & 8 of Schedules 5E & 7E and 5A & 7A.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019

O & M Activities
(in Dollars)

Line		Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period 12-Month	Method of Classification Demand	Method of Classification Energy
1	Description of O & M Activities															
. 1	Sulfur	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 2	Air Emission Fees	2,652	7,867	133,212	2,652	2,652	2,652	2,652	140,152	2,652	2,652	2,652	2,652	305,099	0	305,099
. 3	Title V	22,499	22,499	32,034	23,022	23,022	23,022	23,022	32,034	23,022	23,022	23,026	23,030	293,254	0	293,254
. 4	Asbestos Fees	500	0	0	0	500	0	0	0	0	0	0	0	1,000	1,000	0
. 5	Emission Monitoring	57,923	57,923	66,383	76,007	59,436	59,081	58,957	66,456	59,196	59,071	59,550	59,053	739,036	0	739,036
. 6	General Water Quality	132,136	130,606	165,101	150,256	157,503	196,309	180,209	214,494	185,835	170,908	174,472	156,825	2,014,654	2,014,654	0
. 7	Groundwater Contamination Investigation	228,386	228,386	251,185	231,172	231,172	235,962	235,962	258,370	231,172	231,172	231,172	231,163	2,825,274	2,825,274	0
. 8	State NPDES Administration	11,500	30,500	0	0	0	0	0	0	0	0	0	0	42,000	42,000	0
. 9	Lead & Copper Rule	333	333	333	333	333	333	333	333	333	333	333	337	4,000	4,000	0
. 10	Environmental Auditing/Assessment	0	0	0	0	0	0	0	0	0	7,500	7,500	0	15,000	15,000	0
. 11	General Solid & Hazardous Waste	73,652	72,552	100,655	75,685	76,785	87,285	81,185	98,344	86,285	82,885	81,785	82,902	1,000,000	1,000,000	0
. 12	Above Ground Storage Tanks	5,057	5,057	11,419	5,338	5,569	13,990	5,800	7,353	10,559	5,338	6,031	11,021	92,532	92,532	0
. 13	Low NOx	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 14	Ash Pond Diversion Curtains	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 15	Mercury Emissions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 16	Sodium Injection	600	600	800	700	800	900	900	1,200	800	700	1,000	1,000	10,000	0	10,000
. 17	Gulf Coast Ozone Study	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 18	SPCC Substation Project	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 19	FDEP NOx Reduction Agreement	64,880	64,879	120,574	98,539	37,494	90,127	95,339	117,560	84,563	67,138	85,986	94,195	1,021,274	0	1,021,274
. 20	Air Quality Compliance Program	2,084,683	1,641,424	2,369,448	1,827,875	1,588,503	1,770,349	1,902,486	2,222,251	1,735,346	1,730,382	1,489,349	1,451,695	21,813,790	0	21,813,790
. 21	MACT ICR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 22	Crist Water Conservation	24,901	22,061	44,630	41,844	28,176	35,332	36,861	43,685	34,076	30,417	53,362	33,197	428,542	428,542	0
. 23	Coal Combustion Residuals	473,374	392,817	311,535	460,294	387,121	300,787	173,342	172,896	139,337	139,429	139,444	139,266	3,229,639	3,229,639	0
. 24	Smith Water Conservation	2,500	2,500	2,500	2,500	2,500	2,500	162,500	2,500	2,500	2,500	2,500	2,500	190,000	190,000	0
. 25	Mercury Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 26	Annual NOx Allowances	0	0	514	884	430	504	551	542	501	1,174	984	1,130	7,214	0	7,214
. 27	Seasonal NOx Allowances	0	0	0	0	974	1,816	1,820	2,650	626	0	0	0	7,887	0	7,887
. 28	SO2 Allowances	2,337	1,882	1,874	1,864	3,424	4,664	5,025	5,077	4,200	3,307	1,889	2,219	37,762	0	37,762
. 29	Scherer/Flint Credit - Energy	(30,929)	(73,938)	(90,164)	(41,249)	(38,101)	(35,300)	(35,353)	(35,353)	(35,378)	(31,487)	(34,372)	(31,658)	(513,282)	0	(513,282)
. 30	Scherer/Flint Credit - Demand	(25)	(35)	(56)	(33)	(36)	(32)	(32)	(55)	(33)	(36)	(36)	(30)	(438)	(438)	0
2	Total of O & M Activities	3,156,958	2,607,913	3,521,977	2,957,684	2,568,257	2,790,281	2,931,558	3,350,489	2,565,592	2,526,405	2,326,627	2,260,496	33,564,237	9,842,203	23,722,034
3	Recoverable Costs Allocated to Energy	2,204,644	1,723,136	2,634,675	1,990,294	1,678,633	1,917,816	2,055,399	2,552,570	1,875,528	1,855,959	1,630,065	1,603,315	23,722,034		
4	Recoverable Costs Allocated to Demand	952,314	884,777	887,302	967,389	889,623	872,466	876,159	797,920	690,064	670,446	696,563	657,180	9,842,203		
5	Retail Energy Jurisdictional Factor	0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974			
6	Retail Demand Jurisdictional Factor	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277			
7	Jurisdictional Energy Recoverable Costs (A)	2,142,055	1,675,896	2,563,801	1,938,904	1,636,294	1,870,695	2,004,926	2,488,748	1,827,788	1,808,586	1,585,930	1,557,399	23,101,020		
8	Jurisdictional Demand Recoverable Costs (B)	925,485	859,851	862,305	940,136	864,561	847,886	851,476	775,441	670,623	651,558	676,939	638,666	9,564,925		
9	Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8)	3,067,540	2,535,747	3,426,106	2,879,039	2,500,855	2,718,581	2,856,401	3,264,188	2,498,411	2,460,144	2,262,868	2,196,065	32,665,945		

Notes:
(A) Line 3 x Line 5 x line loss multiplier
(B) Line 4 x Line 6

Schedule 3P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019

Capital Investment Projects - Recoverable Costs
(in Dollars)

Line		Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period 12-Month	Method of Classification Demand	Method of Classification Energy
1	Description of Investment Projects (A)															
. 1	Air Quality Assurance Testing	31	94	156	219	281	343	1,146	1,142	1,137	1,133	1,128	1,124	7,934	7,324	610
. 2	Crist 5, 6 & 7 Precipitator Projects	318,853	318,213	317,572	316,932	316,291	315,651	315,011	314,370	313,730	313,089	312,449	311,808	3,783,969	3,492,895	291,075
. 3	Crist 7 Flue Gas Conditioning	8,641	8,641	8,641	8,641	8,641	8,641	8,641	8,641	8,641	8,641	8,641	8,641	103,687	95,711	7,976
. 4	Low NOx Burners, Crist 6 & 7	148,964	148,698	148,432	148,165	147,899	147,632	147,366	147,099	146,833	146,567	146,300	146,034	1,769,988	1,633,835	136,153
. 5	CEMS - Plants Crist & Daniel	45,428	45,399	45,370	45,629	45,518	46,382	46,295	46,209	46,122	46,036	45,949	45,863	550,201	507,877	42,323
. 6	Substation Contamination Remediation	28,168	32,163	33,551	34,938	36,326	37,713	42,262	42,190	42,117	42,045	41,973	41,900	455,346	420,320	35,027
. 7	Raw Water Well Flowmeters - Plants Crist & Smith	1,099	1,096	1,093	1,090	1,087	1,084	1,082	1,079	1,076	1,073	1,070	1,067	12,997	11,997	1,000
. 8	Crist Cooling Tower Cell	3,065	3,065	3,065	3,065	3,065	3,065	3,065	3,065	3,065	3,065	3,065	3,065	36,786	33,956	2,830
. 9	Crist Dechlorination System	2,042	2,035	2,027	2,020	2,013	2,006	1,998	1,991	1,984	1,977	1,969	1,962	24,024	22,176	1,848
. 10	Crist Diesel Fuel Oil Remediation	331	330	328	327	326	324	323	322	320	319	318	316	3,884	3,585	299
. 11	Crist Bulk Tanker Unloading Secondary Containment	434	432	430	428	426	425	423	421	419	417	415	413	5,083	4,692	391
. 12	Crist IWW Sampling System	253	252	251	249	248	247	246	245	244	243	242	240	2,960	2,732	228
. 13	Sodium Injection System	1,830	1,825	1,819	1,814	1,808	1,803	1,798	1,792	1,787	1,781	1,776	1,771	21,603	19,942	1,662
. 14	Smith Stormwater Collection System	14,825	14,763	14,700	14,638	14,576	14,514	14,452	14,390	14,328	14,266	14,203	14,141	173,796	160,427	13,369
. 15	Smith Waste Water Treatment Facility	4,917	5,932	5,918	5,905	5,892	5,879	5,865	5,852	5,839	5,825	5,812	5,799	69,434	64,093	5,341
. 16	Daniel Ash Management Project	109,297	109,082	108,866	108,651	108,436	108,220	108,005	107,789	107,574	107,359	107,143	106,928	1,297,351	1,197,554	99,796
. 17	Smith Water Conservation	184,629	185,560	187,577	191,657	197,958	205,015	212,827	221,154	229,753	238,351	245,952	252,070	2,552,502	2,356,156	196,346
. 18	Underground Fuel Tank Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 19	Crist FDEP Agreement for Ozone Attainment	908,533	906,168	903,803	901,437	899,072	896,707	894,341	891,976	889,611	887,245	885,168	883,379	10,747,440	9,920,714	826,726
. 20	SPCC Compliance	6,448	6,429	6,410	6,392	6,373	6,354	6,335	6,317	6,298	6,279	6,261	6,242	76,138	70,281	5,857
. 21	Crist Common FTIR Monitor	385	383	382	381	380	379	378	376	375	374	373	372	4,537	4,188	349
. 22	Precipitator Upgrades for CAM Compliance	96,358	96,092	95,826	95,559	95,293	95,027	94,761	94,495	94,228	93,962	93,696	93,430	1,138,727	1,051,133	87,594
. 23	Plant Groundwater Investigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 24	Crist Water Conservation	151,161	150,869	150,532	150,196	149,860	149,524	149,188	148,852	148,516	148,180	147,844	147,508	1,792,231	1,654,367	137,864
. 25	Plant NPDES Permit Compliance Projects	47,354	47,237	47,119	47,002	46,885	46,767	46,650	46,533	46,415	46,298	46,181	46,063	560,503	517,387	43,116
. 26	Air Quality Compliance Program	10,602,004	10,594,935	10,573,165	10,551,395	10,530,635	10,511,317	10,493,841	10,477,429	10,462,935	10,447,626	10,431,685	10,417,484	126,094,451	116,394,877	9,699,573
. 27	General Water Quality	9,175	9,159	9,143	9,127	9,111	9,096	9,080	9,064	9,048	9,032	9,016	9,000	109,051	100,662	8,389
. 28	Coal Combustion Residuals	197,926	234,983	275,652	313,006	360,989	386,536	407,111	447,957	486,919	500,782	513,777	526,840	4,652,479	4,294,596	357,883
. 29	Steam Electric Effluent Limitations Guidelines	50,701	51,233	51,261	51,289	51,316	51,344	51,372	51,400	51,427	51,455	51,483	51,511	615,793	568,424	47,369
30	316(b) Cooling Water Intake Structure Regulation	0	288	864	1,153	1,153	1,297	2,593	6,483	9,581	10,301	11,022	11,454	56,189	51,867	4,322
. 31	Mercury Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 32	Annual NOx Allowances	44	44	43	39	35	32	29	26	23	18	12	6	350	323	27
. 33	Seasonal NOx Allowances	56	56	56	56	54	46	35	22	13	11	11	11	428	395	33
. 34	SO2 Allowances	36,293	36,281	36,270	36,259	36,244	36,221	36,193	36,164	36,137	36,115	36,100	36,089	434,365	400,953	33,413
. 35	Regulatory Asset Sminth Units 1 & 2	233,044	232,361	231,677	230,994	230,311	229,627	228,944	228,260	227,577	226,894	226,210	225,527	2,751,425	2,539,777	211,648
. 36	Scherer/Flint Credit - Energy	(25,069)	(25,198)	(25,318)	(25,438)	(25,919)	(26,038)	(26,084)	(26,513)	(26,486)	(26,459)	(26,432)	(26,405)	(311,360)	0	(311,360)
. 37	Scherer/Flint Credit - Demand	(300,832)	(302,381)	(303,818)	(305,253)	(311,033)	(312,453)	(313,012)	(318,160)	(317,829)	(317,508)	(317,186)	(316,855)	(3,736,320)	(3,736,320)	0
2	Total Investment Projects - Recoverable Costs	12,886,388	12,916,516	12,932,867	12,947,964	12,971,550	12,980,726	12,992,559	13,018,431	13,049,757	13,052,792	13,053,625	13,054,799	155,857,972	143,868,898	11,989,075
3	Recoverable Costs Allocated to Energy	991,261	993,578	994,836	995,997	997,812	998,517	999,428	1,001,418	1,003,827	1,004,061	1,004,125	1,004,215	11,989,075		
4	Recoverable Costs Allocated to Demand	11,895,127	11,922,938	11,938,031	11,951,966	11,973,738	11,982,209	11,993,131	12,017,013	12,045,930	12,048,731	12,049,500	12,050,583	143,868,898		
5	Retail Energy Jurisdictional Factor	0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974			
6	Retail Demand Jurisdictional Factor	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277			
7	Jurisdictional Energy Recoverable Costs (B)	963,119	966,339.39	968,074	970,280	972,644	973,984	974,885	976,379	978,276	978,433	976,938	975,456	11,674,807		
8	Jurisdictional Demand Recoverable Costs (C)	11,560,014	11,587,041	11,601,709	11,615,252	11,636,410	11,644,642	11,655,257	11,678,466	11,706,568	11,709,291	11,710,038	11,711,091	139,815,780		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	12,523,133	12,553,380	12,569,784	12,585,532	12,609,054	12,618,626	12,630,142	12,654,845	12,684,844	12,687,723	12,686,976	12,686,547	151,490,587		

Notes:
(A) Pages 1-30 of Schedule 4P, Line 9, Pages 31-34 of Schedule 4P, Line 6, Page 35, Line 7, Schedule 9P, Line 11 - Line 10 x 24%.
(B) Line 3 x Line 5 x Line loss multiplier
(C) Line 4 x Line 6

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2019 Projection Filing
Exhibit CSB-3, Page 4 of 42

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Air Quality Assurance Testing
P.E.s 1006 & 1244
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		10,833	10,833	10,833	10,833	10,833	10,835	0	0	0	0	0	0	65,000
	b Clearings to Plant		0	0	0	0	0	65,000	0	0	0	0	0	0	65,000
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	65,000	65,000	65,000	65,000	65,000	65,000	65,000	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	(774)	(1,548)	(2,321)	(3,095)	(3,869)	(4,643)	
4	CWIP - Non Interest Bearing	0	10,833	21,666	32,499	43,332	54,165	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	0	10,833	21,666	32,499	43,332	54,165	65,000	64,226	63,452	62,679	61,905	61,131	60,357	
6	Average Net Investment		5,417	16,250	27,083	37,916	48,749	59,583	64,613	63,839	63,065	62,292	61,518	60,744	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		25	75	125	175	225	275	299	295	291	288	284	281	2,639
	b Debt Component (Line 6 x Debt Component x 1/12)		6	19	31	43	56	68	74	73	72	71	70	69	652
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	774	774	774	774	774	774	4,643
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		31	94	156	219	281	343	1,146	1,142	1,137	1,133	1,128	1,124	7,934
	a Recoverable Costs Allocated to Energy		2	7	12	17	22	26	88	88	87	87	87	86	610
	b Recoverable Costs Allocated to Demand		29	86	144	202	259	317	1,058	1,054	1,050	1,046	1,042	1,037	7,324
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		2	7	12	16	21	26	86	86	85	85	84	84	594
13	Retail Demand-Related Recoverable Costs (I)		28	84	140	196	252	308	1,028	1,024	1,020	1,016	1,012	1,008	7,117
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		30	91	152	212	273	334	1,114	1,110	1,105	1,101	1,097	1,092	7,712

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) PE 1244 has a 7-year amortization period. PE 1006 is fully amortized.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist 5, 6 & 7 Precipitator Projects
P.E.s 1038, 1119, 1216, 1243, 1249
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	33,677,323	33,677,323	33,677,323	33,677,323	33,677,323	33,677,323	33,677,323	33,677,323	33,677,323	33,677,323	33,677,323	33,677,323	33,677,323	
3	Less: Accumulated Depreciation (C)	2,421,657	2,310,521	2,199,386	2,088,251	1,977,116	1,865,981	1,754,845	1,643,710	1,532,575	1,421,440	1,310,305	1,199,170	1,088,034	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	36,098,980	35,987,844	35,876,709	35,765,574	35,654,439	35,543,304	35,432,169	35,321,033	35,209,898	35,098,763	34,987,628	34,876,493	34,765,358	
6	Average Net Investment		36,043,412	35,932,277	35,821,142	35,710,007	35,598,871	35,487,736	35,376,601	35,265,466	35,154,331	35,043,196	34,932,060	34,820,925	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		166,557	166,043	165,529	165,016	164,502	163,989	163,475	162,962	162,448	161,935	161,421	160,907	1,964,785
	b Debt Component (Line 6 x Debt Component x 1/12)		41,162	41,035	40,908	40,781	40,654	40,527	40,400	40,273	40,146	40,019	39,892	39,765	485,562
8	Investment Expenses														
	a Depreciation (E)		111,135	111,135	111,135	111,135	111,135	111,135	111,135	111,135	111,135	111,135	111,135	111,135	1,333,622
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		318,853	318,213	317,572	316,932	316,291	315,651	315,011	314,370	313,730	313,089	312,449	311,808	3,783,969
	a Recoverable Costs Allocated to Energy		24,527	24,478	24,429	24,379	24,330	24,281	24,232	24,182	24,133	24,084	24,035	23,985	291,075
	b Recoverable Costs Allocated to Demand		294,326	293,735	293,144	292,553	291,961	291,370	290,779	290,188	289,597	289,005	288,414	287,823	3,492,895
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		23,831	23,807	23,772	23,750	23,716	23,684	23,637	23,578	23,519	23,469	23,384	23,298	283,444
13	Retail Demand-Related Recoverable Costs (I)		286,034	285,460	284,885	284,311	283,736	283,162	282,587	282,012	281,438	280,863	280,289	279,714	3,394,492
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		309,865	309,267	308,657	308,061	307,453	306,846	306,224	305,590	304,957	304,332	303,673	303,013	3,677,936

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist 7 Flue Gas Conditioning
P.E. 1228
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	
6	Average Net Investment		1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		6,928	6,928	6,928	6,928	6,928	6,928	6,928	6,928	6,928	6,928	6,928	6,928	83,140
	b Debt Component (Line 6 x Debt Component x 1/12)		1,712	1,712	1,712	1,712	1,712	1,712	1,712	1,712	1,712	1,712	1,712	1,712	20,547
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		8,641	8,641	8,641	8,641	8,641	8,641	8,641	8,641	8,641	8,641	8,641	8,641	103,687
	a Recoverable Costs Allocated to Energy		665	665	665	665	665	665	665	665	665	665	665	665	7,976
	b Recoverable Costs Allocated to Demand		7,976	7,976	7,976	7,976	7,976	7,976	7,976	7,976	7,976	7,976	7,976	7,976	95,711
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		646	646	647	647	648	648	648	648	648	648	647	646	7,767
13	Retail Demand-Related Recoverable Costs (I)		7,751	7,751	7,751	7,751	7,751	7,751	7,751	7,751	7,751	7,751	7,751	7,751	93,015
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		8,397	8,398	8,398	8,399	8,399	8,400	8,400	8,399	8,399	8,399	8,398	8,397	100,782

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burners, Crist 6 & 7
P.E.s 1234, 1236, 1242, 1284
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	13,634,258	13,634,258	13,634,258	13,634,258	13,634,258	13,634,258	13,634,258	13,634,258	13,634,258	13,634,258	13,634,258	13,634,258	13,634,258	
3	Less: Accumulated Depreciation (C)	4,215,387	4,169,157	4,122,927	4,076,697	4,030,467	3,984,236	3,938,006	3,891,776	3,845,546	3,799,316	3,753,086	3,706,856	3,660,626	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	17,849,645	17,803,415	17,757,185	17,710,955	17,664,725	17,618,495	17,572,265	17,526,035	17,479,805	17,433,575	17,387,345	17,341,115	17,294,884	
6	Average Net Investment		17,826,530	17,780,300	17,734,070	17,687,840	17,641,610	17,595,380	17,549,150	17,502,920	17,456,690	17,410,460	17,364,230	17,317,999	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		82,376	82,163	81,949	81,736	81,522	81,308	81,095	80,881	80,667	80,454	80,240	80,026	974,417
	b Debt Component (Line 6 x Debt Component x 1/12)		20,358	20,305	20,252	20,200	20,147	20,094	20,041	19,988	19,936	19,883	19,830	19,777	240,810
8	Investment Expenses														
	a Depreciation (E)		44,519	44,519	44,519	44,519	44,519	44,519	44,519	44,519	44,519	44,519	44,519	44,519	534,224
	b Amortization (F)		1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	20,537
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		148,964	148,698	148,432	148,165	147,899	147,632	147,366	147,099	146,833	146,567	146,300	146,034	1,769,988
	a Recoverable Costs Allocated to Energy		11,459	11,438	11,418	11,397	11,377	11,356	11,336	11,315	11,295	11,274	11,254	11,233	136,153
	b Recoverable Costs Allocated to Demand		137,506	137,260	137,014	136,768	136,522	136,276	136,030	135,784	135,538	135,292	135,046	134,800	1,633,835
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		11,133	11,125	11,111	11,103	11,090	11,077	11,057	11,032	11,007	10,987	10,949	10,912	132,584
13	Retail Demand-Related Recoverable Costs (I)		133,632	133,393	133,154	132,915	132,676	132,437	132,198	131,959	131,720	131,481	131,242	131,003	1,587,807
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		144,765	144,517	144,264	144,018	143,766	143,514	143,255	142,991	142,727	142,467	142,191	141,914	1,720,390

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Portions of PE 1236 have a 7-year amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: CEMS - Plants Crist & Daniel
P.E.s 1001, 1060, 1154, 1164, 1217, 1240, 1245, 1247, 1256, 1283, 1286, 1289, 1290, 1311, 1312, 1316, 1323, 1324, 1325, 1357, 1358, 1364, 1558, 1570, 1592, 1658, 1829, 1830
(in Dollars)

Line		Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1		Investments														
	a	Expenditures/Additions		0	0	0	100,000	100,000	0	0	0	0	0	0	0	200,000
	b	Clearings to Plant		0	0	0	0	200,000	0	0	0	0	0	0	0	200,000
	c	Retirements		0	0	0	200,000	0	0	0	0	0	0	0	0	200,000
	d	Cost of Removal		0	20,000	0	20,000	0	0	0	0	0	0	0	0	40,000
	e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2		Plant-in-Service/Depreciation Base (B)	4,690,600	4,690,600	4,690,600	4,690,600	4,490,600	4,690,600	4,690,600	4,690,600	4,690,600	4,690,600	4,690,600	4,690,600	4,690,600	
3		Less: Accumulated Depreciation (C)	447,258	432,247	437,236	422,224	627,213	612,861	597,850	582,838	567,827	552,815	537,804	522,792	507,781	
4		CWIP - Non Interest Bearing	0	0	0	0	100,000	0	0	0	0	0	0	0	0	
5		Net Investment (Lines 2 + 3 + 4) (A)	5,137,858	5,122,847	5,127,835	5,112,824	5,217,813	5,303,461	5,288,450	5,273,438	5,258,427	5,243,415	5,228,404	5,213,392	5,198,381	
6		Average Net Investment		5,130,353	5,125,341	5,120,330	5,165,318	5,260,637	5,295,955	5,280,944	5,265,932	5,250,921	5,235,909	5,220,898	5,205,886	
7		Return on Average Net Investment														
	a	Equity Component (Line 6 x Equity Component x 1/12) (D)		23,707	23,684	23,661	23,869	24,309	24,473	24,403	24,334	24,265	24,195	24,126	24,056	289,082
	b	Debt Component (Line 6 x Debt Component x 1/12)		5,859	5,853	5,847	5,899	6,008	6,048	6,031	6,014	5,997	5,979	5,962	5,945	71,442
8		Investment Expenses														
	a	Depreciation (E)		15,011	15,011	15,011	15,011	14,351	15,011	15,011	15,011	15,011	15,011	15,011	15,011	179,478
	b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Property Taxes		850	850	850	850	850	850	850	850	850	850	850	850	10,199
	e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9		Total System Recoverable Expenses (Lines 7 + 8)		45,428	45,399	45,370	45,629	45,518	46,382	46,295	46,209	46,122	46,036	45,949	45,863	550,201
	a	Recoverable Costs Allocated to Energy		3,494	3,492	3,490	3,510	3,501	3,568	3,561	3,555	3,548	3,541	3,535	3,528	42,323
	b	Recoverable Costs Allocated to Demand		41,933	41,906	41,880	42,119	42,017	42,814	42,734	42,654	42,575	42,495	42,415	42,335	507,877
10		Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11		Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12		Retail Energy-Related Recoverable Costs (H)		3,395	3,396	3,396	3,419	3,413	3,480	3,474	3,466	3,458	3,451	3,439	3,427	41,214
13		Retail Demand-Related Recoverable Costs (I)		40,752	40,726	40,700	40,933	40,833	41,608	41,530	41,453	41,375	41,298	41,220	41,142	493,569
14		Total Jurisdictional Recoverable Costs (Lines 12 + 13)		44,147	44,122	44,096	44,352	44,246	45,088	45,004	44,918	44,833	44,748	44,659	44,569	534,783

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning Balances: Crist $4,106,227; Daniel $584,373. Ending Balances: Crist $4,106,227; Daniel $584,373.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) PEs 1364, 1658 and 1283 are fully amortized.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Substation Contamination Remediation
P.E.s 1007, 2859, 3400, 3412, 3463, 3477
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		249,416	249,416	249,416	249,416	249,416	249,416	0	0	0	0	0	0	1,496,496
	b Clearings to Plant		1,000,000	0	0	0	0	1,496,496	0	0	0	0	0	0	2,496,496
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	2,483,333	3,483,333	3,483,333	3,483,333	3,483,333	3,483,333	4,979,829	4,979,829	4,979,829	4,979,829	4,979,829	4,979,829	4,979,829	
3	Less: Accumulated Depreciation (C)	(598,002)	(604,051)	(612,701)	(621,351)	(630,000)	(638,650)	(647,300)	(659,840)	(672,381)	(684,921)	(697,462)	(710,002)	(722,543)	
4	CWIP - Non Interest Bearing	1,831,000	1,080,416	1,329,832	1,579,248	1,828,664	2,078,080	831,000	831,000	831,000	831,000	831,000	831,000	831,000	
5	Net Investment (Lines 2 + 3 + 4) (A)	3,716,332	3,959,698	4,200,465	4,441,231	4,681,997	4,922,764	5,163,530	5,150,989	5,138,449	5,125,908	5,113,368	5,100,827	5,088,287	
6	Average Net Investment		3,838,015	4,080,081	4,320,848	4,561,614	4,802,380	5,043,147	5,157,260	5,144,719	5,132,179	5,119,638	5,107,097	5,094,557	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		17,735	18,854	19,967	21,079	22,192	23,304	23,832	23,774	23,716	23,658	23,600	23,542	265,252
	b Debt Component (Line 6 x Debt Component x 1/12)		4,383	4,659	4,934	5,209	5,484	5,759	5,890	5,875	5,861	5,847	5,832	5,818	65,553
8	Investment Expenses														
	a Depreciation (E)		6,050	8,650	8,650	8,650	8,650	8,650	12,541	12,541	12,541	12,541	12,541	12,541	124,541
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		28,168	32,163	33,551	34,938	36,326	37,713	42,262	42,190	42,117	42,045	41,973	41,900	455,346
	a Recoverable Costs Allocated to Energy		2,167	2,474	2,581	2,688	2,794	2,901	3,251	3,245	3,240	3,234	3,229	3,223	35,027
	b Recoverable Costs Allocated to Demand		26,001	29,689	30,970	32,251	33,532	34,812	39,011	38,944	38,878	38,811	38,744	38,677	420,320
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		2,105	2,406	2,511	2,618	2,724	2,830	3,171	3,164	3,157	3,152	3,141	3,131	34,111
13	Retail Demand-Related Recoverable Costs (I)		25,269	28,853	30,097	31,342	32,587	33,832	37,912	37,847	37,782	37,717	37,653	37,588	408,478
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		27,374	31,259	32,609	33,960	35,311	36,661	41,083	41,011	40,940	40,869	40,794	40,719	442,589

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) PE 1007 is fully amortized.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Raw Water Well Flowmeters - Plants Crist & Smith
P.E.s 1155 & 1606
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	
3	Less: Accumulated Depreciation (C)	(44,911)	(45,406)	(45,901)	(46,396)	(46,891)	(47,385)	(47,880)	(48,375)	(48,870)	(49,365)	(49,860)	(50,354)	(50,849)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	105,038	104,544	104,049	103,554	103,059	102,564	102,069	101,575	101,080	100,585	100,090	99,595	99,100	
6	Average Net Investment		104,791	104,296	103,801	103,306	102,812	102,317	101,822	101,327	100,832	100,337	99,843	99,348	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		484	482	480	477	475	473	471	468	466	464	461	459	5,660
	b Debt Component (Line 6 x Debt Component x 1/12)		120	119	119	118	117	117	116	116	115	115	114	113	1,399
8	Investment Expenses														
	a Depreciation (E)		495	495	495	495	495	495	495	495	495	495	495	495	5,938
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,099	1,096	1,093	1,090	1,087	1,084	1,082	1,079	1,076	1,073	1,070	1,067	12,997
	a Recoverable Costs Allocated to Energy		85	84	84	84	84	83	83	83	83	83	82	82	1,000
	b Recoverable Costs Allocated to Demand		1,014	1,012	1,009	1,006	1,004	1,001	998	996	993	991	988	985	11,997
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		82	82	82	82	82	81	81	81	81	80	80	80	974
13	Retail Demand-Related Recoverable Costs (I)		986	983	981	978	975	973	970	968	965	963	960	958	11,659
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,068	1,065	1,062	1,060	1,057	1,054	1,051	1,049	1,046	1,043	1,040	1,037	12,632

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Cooling Tower Cell
P.E. 1232
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	
6	Average Net Investment		531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,458	2,458	2,458	2,458	2,458	2,458	2,458	2,458	2,458	2,458	2,458	2,458	29,496
	b Debt Component (Line 6 x Debt Component x 1/12)		607	607	607	607	607	607	607	607	607	607	607	607	7,290
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		3,065	3,065	3,065	3,065	3,065	3,065	3,065	3,065	3,065	3,065	3,065	3,065	36,786
	a Recoverable Costs Allocated to Energy		236	236	236	236	236	236	236	236	236	236	236	236	2,830
	b Recoverable Costs Allocated to Demand		2,830	2,830	2,830	2,830	2,830	2,830	2,830	2,830	2,830	2,830	2,830	2,830	33,956
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		229	229	229	230	230	230	230	230	230	230	229	229	2,756
13	Retail Demand-Related Recoverable Costs (I)		2,750	2,750	2,750	2,750	2,750	2,750	2,750	2,750	2,750	2,750	2,750	2,750	33,000
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,979	2,979	2,979	2,980	2,980	2,980	2,980	2,980	2,980	2,980	2,979	2,979	35,755

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Dechlorination System
P.E.s 1180 & 1248
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	
3	Less: Accumulated Depreciation (C)	(243,768)	(245,024)	(246,281)	(247,537)	(248,793)	(250,049)	(251,306)	(252,562)	(253,818)	(255,075)	(256,331)	(257,587)	(258,844)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	136,929	135,673	134,417	133,160	131,904	130,648	129,391	128,135	126,879	125,622	124,366	123,110	121,854	
6	Average Net Investment		136,301	135,045	133,788	132,532	131,276	130,019	128,763	127,507	126,251	124,994	123,738	122,482	
7	Return on Average Net Investment														
a	Equity Component (Line 6 x Equity Component x 1/12) (D)		630	624	618	612	607	601	595	589	583	578	572	566	7,175
b	Debt Component (Line 6 x Debt Component x 1/12)		156	154	153	151	150	148	147	146	144	143	141	140	1,773
8	Investment Expenses														
a	Depreciation (E)		1,256	1,256	1,256	1,256	1,256	1,256	1,256	1,256	1,256	1,256	1,256	1,256	15,076
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,042	2,035	2,027	2,020	2,013	2,006	1,998	1,991	1,984	1,977	1,969	1,962	24,024
a	Recoverable Costs Allocated to Energy		157	157	156	155	155	154	154	153	153	152	151	151	1,848
b	Recoverable Costs Allocated to Demand		1,885	1,878	1,871	1,865	1,858	1,851	1,845	1,838	1,831	1,825	1,818	1,811	22,176
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		153	152	152	151	151	150	150	149	149	148	147	147	1,800
13	Retail Demand-Related Recoverable Costs (I)		1,832	1,825	1,819	1,812	1,806	1,799	1,793	1,786	1,780	1,773	1,767	1,760	21,551
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,984	1,977	1,970	1,964	1,957	1,950	1,943	1,936	1,928	1,921	1,914	1,907	23,351

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Diesel Fuel Oil Remediation
P.E. 1270
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	
3	Less: Accumulated Depreciation (C)	(50,860)	(51,088)	(51,315)	(51,543)	(51,770)	(51,997)	(52,225)	(52,452)	(52,680)	(52,907)	(53,135)	(53,362)	(53,590)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	18,063	17,835	17,608	17,381	17,153	16,926	16,698	16,471	16,243	16,016	15,788	15,561	15,333	
6	Average Net Investment		17,949	17,722	17,494	17,267	17,039	16,812	16,584	16,357	16,130	15,902	15,675	15,447	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		83	82	81	80	79	78	77	76	75	73	72	71	926
	b Debt Component (Line 6 x Debt Component x 1/12)		20	20	20	20	19	19	19	19	18	18	18	18	229
8	Investment Expenses														
	a Depreciation (E)		227	227	227	227	227	227	227	227	227	227	227	227	2,729
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		331	330	328	327	326	324	323	322	320	319	318	316	3,884
	a Recoverable Costs Allocated to Energy		25	25	25	25	25	25	25	25	25	25	24	24	299
	b Recoverable Costs Allocated to Demand		305	304	303	302	301	299	298	297	296	295	293	292	3,585
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		25	25	25	25	24	24	24	24	24	24	24	24	291
13	Retail Demand-Related Recoverable Costs (I)		297	296	294	293	292	291	290	289	287	286	285	284	3,484
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		322	320	319	318	317	315	314	313	311	310	309	308	3,775

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Bulk Tanker Unloading Secondary Containment
P.E. 1271
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	
3	Less: Accumulated Depreciation (C)	(84,109)	(84,443)	(84,778)	(85,113)	(85,448)	(85,783)	(86,118)	(86,453)	(86,788)	(87,123)	(87,458)	(87,793)	(88,128)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	17,387	17,052	16,717	16,382	16,047	15,712	15,377	15,042	14,707	14,372	14,037	13,702	13,367	
6	Average Net Investment		17,219	16,884	16,549	16,214	15,879	15,544	15,210	14,875	14,540	14,205	13,870	13,535	
7	Return on Average Net Investment														
a	Equity Component (Line 6 x Equity Component x 1/12) (D)		80	78	76	75	73	72	70	69	67	66	64	63	853
b	Debt Component (Line 6 x Debt Component x 1/12)		20	19	19	19	18	18	17	17	17	16	16	15	211
8	Investment Expenses														
a	Depreciation (E)		335	335	335	335	335	335	335	335	335	335	335	335	4,019
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		434	432	430	428	426	425	423	421	419	417	415	413	5,083
a	Recoverable Costs Allocated to Energy		33	33	33	33	33	33	33	32	32	32	32	32	391
b	Recoverable Costs Allocated to Demand		401	399	397	395	394	392	390	388	387	385	383	381	4,692
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		32	32	32	32	32	32	32	32	31	31	31	31	381
13	Retail Demand-Related Recoverable Costs (I)		389	388	386	384	383	381	379	377	376	374	372	370	4,559
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		422	420	418	416	415	413	411	409	407	405	403	401	4,940

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist IWW Sampling System
P.E. 1275
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	
3	Less: Accumulated Depreciation (C)	(49,661)	(49,858)	(50,054)	(50,251)	(50,447)	(50,644)	(50,840)	(51,037)	(51,233)	(51,430)	(51,626)	(51,823)	(52,019)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	9,882	9,685	9,489	9,292	9,096	8,899	8,703	8,506	8,310	8,113	7,917	7,720	7,524	
6	Average Net Investment		9,783	9,587	9,390	9,194	8,997	8,801	8,604	8,408	8,211	8,015	7,818	7,622	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		45	44	43	42	42	41	40	39	38	37	36	35	483
	b Debt Component (Line 6 x Debt Component x 1/12)		11	11	11	10	10	10	10	10	9	9	9	9	119
8	Investment Expenses														
	a Depreciation (E)		196	196	196	196	196	196	196	196	196	196	196	196	2,358
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		253	252	251	249	248	247	246	245	244	243	242	240	2,960
	a Recoverable Costs Allocated to Energy		19	19	19	19	19	19	19	19	19	19	19	18	228
	b Recoverable Costs Allocated to Demand		233	232	231	230	229	228	227	226	225	224	223	222	2,732
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		19	19	19	19	19	19	18	18	18	18	18	18	222
13	Retail Demand-Related Recoverable Costs (I)		227	226	225	224	223	222	221	220	219	218	217	216	2,655
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		246	245	244	242	241	240	239	238	237	236	235	234	2,877

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Sodium Injection System
P.E. 1214
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	
3	Less: Accumulated Depreciation (C)	(129,581)	(130,520)	(131,459)	(132,398)	(133,338)	(134,277)	(135,216)	(136,155)	(137,095)	(138,034)	(138,973)	(139,912)	(140,852)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	155,041	154,102	153,163	152,223	151,284	150,345	149,406	148,466	147,527	146,588	145,649	144,709	143,770	
6	Average Net Investment		154,572	153,632	152,693	151,754	150,815	149,875	148,936	147,997	147,058	146,118	145,179	144,240	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		714	710	706	701	697	693	688	684	680	675	671	667	8,285
	b Debt Component (Line 6 x Debt Component x 1/12)		177	175	174	173	172	171	170	169	168	167	166	165	2,047
8	Investment Expenses														
	a Depreciation (E)		939	939	939	939	939	939	939	939	939	939	939	939	11,271
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,830	1,825	1,819	1,814	1,808	1,803	1,798	1,792	1,787	1,781	1,776	1,771	21,603
	a Recoverable Costs Allocated to Energy		141	140	140	140	139	139	138	138	137	137	137	136	1,662
	b Recoverable Costs Allocated to Demand		1,689	1,684	1,679	1,674	1,669	1,664	1,659	1,654	1,649	1,644	1,639	1,634	19,942
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		137	137	136	136	136	135	135	134	134	134	133	132	1,618
13	Retail Demand-Related Recoverable Costs (I)		1,642	1,637	1,632	1,627	1,622	1,617	1,613	1,608	1,603	1,598	1,593	1,588	19,380
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,778	1,773	1,768	1,763	1,758	1,753	1,747	1,742	1,737	1,732	1,726	1,721	20,998

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Smith Stormwater Collection System
P.E. 1446
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	
3	Less: Accumulated Depreciation (C)	(2,057,330)	(2,068,111)	(2,078,892)	(2,089,673)	(2,100,454)	(2,111,236)	(2,122,017)	(2,132,798)	(2,143,579)	(2,154,360)	(2,165,141)	(2,175,922)	(2,186,703)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	707,049	696,267	685,486	674,705	663,924	653,143	642,362	631,581	620,800	610,019	599,238	588,457	577,676	
6	Average Net Investment		701,658	690,877	680,096	669,315	658,534	647,753	636,972	626,190	615,409	604,628	593,847	583,066	
7	Return on Average Net Investment														
a	Equity Component (Line 6 x Equity Component x 1/12) (D)		3,242	3,193	3,143	3,093	3,043	2,993	2,943	2,894	2,844	2,794	2,744	2,694	35,620
b	Debt Component (Line 6 x Debt Component x 1/12)		801	789	777	764	752	740	727	715	703	690	678	666	8,803
8	Investment Expenses														
a	Depreciation (E)		10,781	10,781	10,781	10,781	10,781	10,781	10,781	10,781	10,781	10,781	10,781	10,781	129,373
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		14,825	14,763	14,700	14,638	14,576	14,514	14,452	14,390	14,328	14,266	14,203	14,141	173,796
a	Recoverable Costs Allocated to Energy		1,140	1,136	1,131	1,126	1,121	1,116	1,112	1,107	1,102	1,097	1,093	1,088	13,369
b	Recoverable Costs Allocated to Demand		13,684	13,627	13,570	13,512	13,455	13,398	13,340	13,283	13,226	13,168	13,111	13,054	160,427
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		1,108	1,104	1,100	1,097	1,093	1,089	1,084	1,079	1,074	1,069	1,063	1,057	13,018
13	Retail Demand-Related Recoverable Costs (I)		13,299	13,243	13,187	13,132	13,076	13,020	12,964	12,909	12,853	12,797	12,741	12,686	155,908
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		14,407	14,348	14,288	14,229	14,169	14,109	14,049	13,988	13,927	13,867	13,804	13,742	168,926

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Smith Waste Water Treatment Facility
P.E.s 1466 & 1643
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Clearings to Plant		262,903	0	0	0	0	0	0	0	0	0	0	0	262,903
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	328,962	591,865	591,865	591,865	591,865	591,865	591,865	591,865	591,865	591,865	591,865	591,865	591,865	
3	Less: Accumulated Depreciation (C)	39,323	38,040	35,731	33,423	31,115	28,807	26,498	24,190	21,882	19,573	17,265	14,957	12,649	
4	CWIP - Non Interest Bearing	262,903	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	631,188	629,905	627,596	625,288	622,980	620,672	618,363	616,055	613,747	611,438	609,130	606,822	604,514	
6	Average Net Investment		630,546	628,750	626,442	624,134	621,826	619,517	617,209	614,901	612,593	610,284	607,976	605,668	
7	Return on Average Net Investment														
a	Equity Component (Line 6 x Equity Component x 1/12) (D)		2,914	2,905	2,895	2,884	2,873	2,863	2,852	2,841	2,831	2,820	2,809	2,799	34,287
b	Debt Component (Line 6 x Debt Component x 1/12)		720	718	715	713	710	707	705	702	700	697	694	692	8,473
8	Investment Expenses														
a	Depreciation (E)		1,283	2,308	2,308	2,308	2,308	2,308	2,308	2,308	2,308	2,308	2,308	2,308	26,674
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		4,917	5,932	5,918	5,905	5,892	5,879	5,865	5,852	5,839	5,825	5,812	5,799	69,434
a	Recoverable Costs Allocated to Energy		378	456	455	454	453	452	451	450	449	448	447	446	5,341
b	Recoverable Costs Allocated to Demand		4,539	5,475	5,463	5,451	5,439	5,426	5,414	5,402	5,390	5,377	5,365	5,353	64,093
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		367	444	443	443	442	441	440	439	438	437	435	433	5,201
13	Retail Demand-Related Recoverable Costs (I)		4,411	5,321	5,309	5,297	5,285	5,273	5,262	5,250	5,238	5,226	5,214	5,202	62,288
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		4,778	5,765	5,752	5,740	5,727	5,715	5,702	5,689	5,675	5,662	5,649	5,635	67,489

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Daniel Ash Management Project
P.E.s 1501, 1535, 1555, 1819
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	
3	Less: Accumulated Depreciation (C)	(6,384,689)	(6,422,064)	(6,459,439)	(6,496,815)	(6,534,190)	(6,571,565)	(6,608,941)	(6,646,316)	(6,683,691)	(6,721,066)	(6,758,442)	(6,795,817)	(6,833,192)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	8,565,435	8,528,060	8,490,685	8,453,309	8,415,934	8,378,559	8,341,183	8,303,808	8,266,433	8,229,058	8,191,682	8,154,307	8,116,932	
6	Average Net Investment		8,546,748	8,509,372	8,471,997	8,434,622	8,397,246	8,359,871	8,322,496	8,285,120	8,247,745	8,210,370	8,172,995	8,135,619	
7	Return on Average Net Investment														
a	Equity Component (Line 6 x Equity Component x 1/12) (D)		39,495	39,322	39,149	38,976	38,804	38,631	38,458	38,286	38,113	37,940	37,767	37,595	462,535
b	Debt Component (Line 6 x Debt Component x 1/12)		9,760	9,718	9,675	9,632	9,590	9,547	9,504	9,462	9,419	9,376	9,334	9,291	114,308
8	Investment Expenses														
a	Depreciation (E)		37,375	37,375	37,375	37,375	37,375	37,375	37,375	37,375	37,375	37,375	37,375	37,375	448,504
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Property Taxes		22,667	22,667	22,667	22,667	22,667	22,667	22,667	22,667	22,667	22,667	22,667	22,667	272,004
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		109,297	109,082	108,866	108,651	108,436	108,220	108,005	107,789	107,574	107,359	107,143	106,928	1,297,351
a	Recoverable Costs Allocated to Energy		8,407	8,391	8,374	8,358	8,341	8,325	8,308	8,291	8,275	8,258	8,242	8,225	99,796
b	Recoverable Costs Allocated to Demand		100,890	100,691	100,492	100,293	100,094	99,896	99,697	99,498	99,299	99,100	98,901	98,703	1,197,554
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		8,169	8,161	8,149	8,142	8,131	8,120	8,104	8,084	8,064	8,048	8,019	7,990	97,180
13	Retail Demand-Related Recoverable Costs (I)		98,047	97,854	97,661	97,468	97,275	97,081	96,888	96,695	96,502	96,308	96,115	95,922	1,163,817
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		106,216	106,015	105,810	105,610	105,405	105,201	104,992	104,779	104,566	104,356	104,134	103,912	1,260,997

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Smith Water Conservation
P.E. 1601
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		81,880	382,578	458,872	1,098,446	1,229,620	1,360,795	1,491,970	1,539,144	1,586,318	1,539,144	1,239,970	1,024,795	13,033,532
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	16,169,371	16,169,371
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	18,130,435	18,130,435	18,130,435	18,130,435	18,130,435	18,130,435	18,130,435	18,130,435	18,130,435	18,130,435	18,130,435	18,130,435	34,299,806	
3	Less: Accumulated Depreciation (C)	(1,504,305)	(1,575,014)	(1,645,723)	(1,716,431)	(1,787,140)	(1,857,849)	(1,928,557)	(1,999,266)	(2,069,975)	(2,140,684)	(2,211,392)	(2,282,101)	(2,352,810)	
4	CWIP - Non Interest Bearing	3,135,839	3,217,719	3,600,297	4,059,169	5,157,615	6,387,235	7,748,030	9,240,000	10,779,144	12,365,462	13,904,606	15,144,576	(0)	
5	Net Investment (Lines 2 + 3 + 4) (A)	19,761,969	19,773,140	20,085,009	20,473,173	21,500,910	22,659,821	23,949,908	25,371,169	26,839,604	28,355,213	29,823,649	30,992,910	31,946,996	
6	Average Net Investment		19,767,554	19,929,075	20,279,091	20,987,041	22,080,366	23,304,864	24,660,538	26,105,387	27,597,409	29,089,431	30,408,279	31,469,953	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		91,346	92,092	93,710	96,981	102,033	107,692	113,956	120,633	127,528	134,422	140,517	145,423	1,366,333
	b Debt Component (Line 6 x Debt Component x 1/12)		22,575	22,759	23,159	23,967	25,216	26,614	28,162	29,812	31,516	33,220	34,726	35,939	337,665
8	Investment Expenses														
	a Depreciation (E)		70,709	70,709	70,709	70,709	70,709	70,709	70,709	70,709	70,709	70,709	70,709	70,709	848,504
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		184,629	185,560	187,577	191,657	197,958	205,015	212,827	221,154	229,753	238,351	245,952	252,070	2,552,502
	a Recoverable Costs Allocated to Energy		14,202	14,274	14,429	14,743	15,228	15,770	16,371	17,012	17,673	18,335	18,919	19,390	196,346
	b Recoverable Costs Allocated to Demand		170,427	171,286	173,148	176,914	182,730	189,244	196,456	204,142	212,079	220,016	227,032	232,680	2,356,156
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		13,799	13,883	14,041	14,362	14,843	15,383	15,969	16,587	17,223	17,867	18,407	18,835	191,199
13	Retail Demand-Related Recoverable Costs (I)		165,626	166,461	168,270	171,930	177,582	183,913	190,921	198,391	206,105	213,818	220,636	226,125	2,289,778
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		179,425	180,343	182,311	186,292	192,426	199,296	206,891	214,978	223,328	231,685	239,043	244,960	2,480,976

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Underground Fuel Tank Replacement
P.E. 4397
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	0	0	0	0	0	0	0	0	0	0	0	0	0	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 6 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) PE 4397 fully amortized.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist FDEP Agreement for Ozone Attainment
P.E.s 1031, 1158, 1167, 1199, 1250, 1258, 1287, 1958
(in Dollars)

Line		Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1		Investments														
	a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	100,000	100,000	200,000
	b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2		Plant-in-Service/Depreciation Base (B)	122,186,973	122,186,973	122,186,973	122,186,973	122,186,973	122,186,973	122,186,973	122,186,973	122,186,973	122,186,973	122,186,973	122,186,973	122,186,973	
3		Less: Accumulated Depreciation (C)	(35,551,259)	(35,961,693)	(36,372,127)	(36,782,562)	(37,192,996)	(37,603,430)	(38,013,865)	(38,424,299)	(38,834,733)	(39,245,167)	(39,655,602)	(40,066,036)	(40,476,470)	
4		CWIP - Non Interest Bearing	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	100,000	200,000	
5		Net Investment (Lines 2 + 3 + 4) (A)	86,635,714	86,225,280	85,814,846	85,404,411	84,993,977	84,583,543	84,173,108	83,762,674	83,352,240	82,941,805	82,531,371	82,220,937	81,910,502	
6		Average Net Investment		86,430,497	86,020,063	85,609,628	85,199,194	84,788,760	84,378,325	83,967,891	83,557,457	83,147,022	82,736,588	82,376,154	82,065,720	
7		Return on Average Net Investment														
	a	Equity Component (Line 6 x Equity Component x 1/12) (D)		399,395	397,499	395,602	393,705	391,809	389,912	388,016	386,119	384,222	382,326	380,660	379,226	4,668,491
	b	Debt Component (Line 6 x Debt Component x 1/12)		98,704	98,235	97,766	97,297	96,829	96,360	95,891	95,423	94,954	94,485	94,074	93,719	1,153,737
8		Investment Expenses														
	a	Depreciation (E)		400,430	400,430	400,430	400,430	400,430	400,430	400,430	400,430	400,430	400,430	400,430	400,430	4,805,154
	b	Amortization (F)		10,005	10,005	10,005	10,005	10,005	10,005	10,005	10,005	10,005	10,005	10,005	10,005	120,058
	c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9		Total System Recoverable Expenses (Lines 7 + 8)		908,533	906,168	903,803	901,437	899,072	896,707	894,341	891,976	889,611	887,245	885,168	883,379	10,747,440
	a	Recoverable Costs Allocated to Energy		69,887	69,705	69,523	69,341	69,159	68,977	68,795	68,614	68,432	68,250	68,090	67,952	826,726
	b	Recoverable Costs Allocated to Demand		838,646	836,463	834,279	832,096	829,913	827,729	825,546	823,362	821,179	818,996	817,078	815,427	9,920,714
10		Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11		Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12		Retail Energy-Related Recoverable Costs (H)		67,903	67,794	67,653	67,551	67,415	67,283	67,106	66,898	66,690	66,508	66,246	66,006	805,053
13		Retail Demand-Related Recoverable Costs (I)		815,019	812,898	810,776	808,654	806,532	804,410	802,288	800,166	798,045	795,923	794,059	792,454	9,641,224
14		Total Jurisdictional Recoverable Costs (Lines 12 + 13)		882,923	880,692	878,429	876,205	873,947	871,693	869,394	867,064	864,734	862,430	860,306	858,461	10,446,277

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Portions of PEs 1158, 1167 and 1199 have a 7-year amortization period. PE 1287 is fully amortized.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: SPCC Compliance
P.E.s 1272, 1404, 1628, 4418
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	947,925	947,925	947,925	947,925	947,925	947,925	947,925	947,925	947,925	947,925	947,925	947,925	947,925	
3	Less: Accumulated Depreciation (C)	(391,513)	(394,763)	(398,014)	(401,264)	(404,515)	(407,766)	(411,016)	(414,267)	(417,518)	(420,768)	(424,019)	(427,269)	(430,520)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	556,412	553,162	549,911	546,660	543,410	540,159	536,908	533,658	530,407	527,157	523,906	520,655	517,405	
6	Average Net Investment		554,787	551,536	548,286	545,035	541,784	538,534	535,283	532,033	528,782	525,531	522,281	519,030	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,564	2,549	2,534	2,519	2,504	2,489	2,474	2,459	2,444	2,428	2,413	2,398	29,773
	b Debt Component (Line 6 x Debt Component x 1/12)		634	630	626	622	619	615	611	608	604	600	596	593	7,358
8	Investment Expenses														
	a Depreciation (E)		3,094	3,094	3,094	3,094	3,094	3,094	3,094	3,094	3,094	3,094	3,094	3,094	37,123
	b Amortization (F)		157	157	157	157	157	157	157	157	157	157	157	157	1,885
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		6,448	6,429	6,410	6,392	6,373	6,354	6,335	6,317	6,298	6,279	6,261	6,242	76,138
	a Recoverable Costs Allocated to Energy		496	495	493	492	490	489	487	486	484	483	482	480	5,857
	b Recoverable Costs Allocated to Demand		5,952	5,935	5,917	5,900	5,883	5,865	5,848	5,831	5,814	5,796	5,779	5,762	70,281
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		482	481	480	479	478	477	475	474	472	471	469	466	5,703
13	Retail Demand-Related Recoverable Costs (I)		5,784	5,767	5,751	5,734	5,717	5,700	5,683	5,667	5,650	5,633	5,616	5,599	68,301
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		6,266	6,248	6,230	6,213	6,195	6,177	6,159	6,140	6,122	6,104	6,085	6,066	74,004

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning and Ending Balances: Other $13,195; Crist $919,836; Smith $14,895.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) PE 4418 has a 7-year amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Common FTIR Monitor
P.E. 1297
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	
3	Less: Accumulated Depreciation (C)	(32,014)	(32,222)	(32,429)	(32,637)	(32,844)	(33,052)	(33,259)	(33,467)	(33,674)	(33,882)	(34,089)	(34,297)	(34,504)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	30,856	30,648	30,441	30,234	30,026	29,819	29,611	29,404	29,196	28,989	28,781	28,574	28,366	
6	Average Net Investment		30,752	30,545	30,337	30,130	29,922	29,715	29,507	29,300	29,092	28,885	28,678	28,470	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		142	141	140	139	138	137	136	135	134	133	133	132	1,642
	b Debt Component (Line 6 x Debt Component x 1/12)		35	35	35	34	34	34	34	33	33	33	33	33	406
8	Investment Expenses														
	a Depreciation (E)		207	207	207	207	207	207	207	207	207	207	207	207	2,490
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		385	383	382	381	380	379	378	376	375	374	373	372	4,537
	a Recoverable Costs Allocated to Energy		30	29	29	29	29	29	29	29	29	29	29	29	349
	b Recoverable Costs Allocated to Demand		355	354	353	352	351	350	348	347	346	345	344	343	4,188
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		29	29	29	29	28	28	28	28	28	28	28	28	340
13	Retail Demand-Related Recoverable Costs (I)		345	344	343	342	341	340	339	338	337	335	334	333	4,070
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		374	373	372	370	369	368	367	366	365	363	362	361	4,410

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Precipitator Upgrades for CAM Compliance
P.E.s 1175, 1191, 1305, 1330
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	13,997,696	13,997,696	13,997,696	13,997,696	13,997,696	13,997,696	13,997,696	13,997,696	13,997,696	13,997,696	13,997,696	13,997,696	13,997,696	
3	Less: Accumulated Depreciation (C)	(5,269,811)	(5,316,003)	(5,362,196)	(5,408,388)	(5,454,581)	(5,500,773)	(5,546,965)	(5,593,158)	(5,639,350)	(5,685,543)	(5,731,735)	(5,777,927)	(5,824,120)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	8,727,885	8,681,692	8,635,500	8,589,308	8,543,115	8,496,923	8,450,730	8,404,538	8,358,346	8,312,153	8,265,961	8,219,768	8,173,576	
6	Average Net Investment		8,704,789	8,658,596	8,612,404	8,566,211	8,520,019	8,473,827	8,427,634	8,381,442	8,335,249	8,289,057	8,242,865	8,196,672	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		40,225	40,011	39,798	39,584	39,371	39,158	38,944	38,731	38,517	38,304	38,090	37,877	468,610
	b Debt Component (Line 6 x Debt Component x 1/12)		9,941	9,888	9,835	9,783	9,730	9,677	9,624	9,572	9,519	9,466	9,413	9,361	115,809
8	Investment Expenses														
	a Depreciation (E)		46,192	46,192	46,192	46,192	46,192	46,192	46,192	46,192	46,192	46,192	46,192	46,192	554,309
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		96,358	96,092	95,826	95,559	95,293	95,027	94,761	94,495	94,228	93,962	93,696	93,430	1,138,727
	a Recoverable Costs Allocated to Energy		7,412	7,392	7,371	7,351	7,330	7,310	7,289	7,269	7,248	7,228	7,207	7,187	87,594
	b Recoverable Costs Allocated to Demand		88,946	88,700	88,454	88,209	87,963	87,717	87,472	87,226	86,980	86,734	86,489	86,243	1,051,133
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		7,202	7,189	7,173	7,161	7,145	7,130	7,110	7,087	7,064	7,043	7,012	6,981	85,298
13	Retail Demand-Related Recoverable Costs (I)		86,440	86,201	85,963	85,724	85,485	85,246	85,007	84,768	84,530	84,291	84,052	83,813	1,021,520
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		93,642	93,390	93,135	92,885	92,630	92,376	92,118	91,856	91,594	91,334	91,064	90,794	1,106,818

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Plant Groundwater Investigation
P.E.s 1218 & 1361
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	0	0	0	0	0	0	0	0	0	0	0	0	0	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment														
a	Equity Component (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Debt Component (Line 6 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
a	Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
a	Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Water Conservation Project
P.E.s 1178, 1227, 1298
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		8,330	8,330	8,330	8,330	8,330	8,330	8,330	8,330	8,330	8,330	8,330	8,370	100,000
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		15,000	0	0	0	0	0	0	0	0	0	0	0	15,000
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	20,195,681	20,195,681	20,195,681	20,195,681	20,195,681	20,195,681	20,195,681	20,195,681	20,195,681	20,195,681	20,195,681	20,195,681	20,195,681	
3	Less: Accumulated Depreciation (C)	(5,508,806)	(5,560,452)	(5,627,097)	(5,693,743)	(5,760,389)	(5,827,035)	(5,893,680)	(5,960,326)	(6,026,972)	(6,093,618)	(6,160,263)	(6,226,909)	(6,293,555)	
4	CWIP - Non Interest Bearing	0	8,330	16,660	24,990	33,320	41,650	49,980	58,310	66,640	74,970	83,300	91,630	100,000	
5	Net Investment (Lines 2 + 3 + 4) (A)	14,686,875	14,643,559	14,585,243	14,526,928	14,468,612	14,410,296	14,351,980	14,293,665	14,235,349	14,177,033	14,118,717	14,060,402	14,002,126	
6	Average Net Investment		14,665,217	14,614,401	14,556,085	14,497,770	14,439,454	14,381,138	14,322,822	14,264,507	14,206,191	14,147,875	14,089,559	14,031,264	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		67,768	67,533	67,264	66,994	66,725	66,455	66,186	65,916	65,647	65,377	65,108	64,838	795,811
	b Debt Component (Line 6 x Debt Component x 1/12)		16,748	16,690	16,623	16,556	16,490	16,423	16,357	16,290	16,223	16,157	16,090	16,024	196,671
8	Investment Expenses														
	a Depreciation (E)		66,646	66,646	66,646	66,646	66,646	66,646	66,646	66,646	66,646	66,646	66,646	66,646	799,749
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		151,161	150,869	150,532	150,196	149,860	149,524	149,188	148,852	148,516	148,180	147,844	147,508	1,792,231
	a Recoverable Costs Allocated to Energy		11,628	11,605	11,579	11,554	11,528	11,502	11,476	11,450	11,424	11,398	11,373	11,347	137,864
	b Recoverable Costs Allocated to Demand		139,534	139,263	138,953	138,643	138,333	138,022	137,712	137,402	137,092	136,782	136,471	136,161	1,654,367
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		11,298	11,287	11,268	11,255	11,237	11,219	11,194	11,164	11,134	11,108	11,065	11,022	134,250
13	Retail Demand-Related Recoverable Costs (I)		135,603	135,340	135,038	134,737	134,435	134,134	133,832	133,531	133,230	132,928	132,627	132,325	1,607,760
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		146,900	146,627	146,306	145,992	145,672	145,353	145,027	144,695	144,363	144,036	143,691	143,347	1,742,010

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Plant NPDES Permit Compliance Projects
P.E.s 0433, 1204 & 1299
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	6,167,068	6,167,068	6,167,068	6,167,068	6,167,068	6,167,068	6,167,068	6,167,068	6,167,068	6,167,068	6,167,068	6,167,068	6,167,068	
3	Less: Accumulated Depreciation (C)	(2,158,179)	(2,178,538)	(2,198,898)	(2,219,258)	(2,239,617)	(2,259,977)	(2,280,337)	(2,300,697)	(2,321,056)	(2,341,416)	(2,361,776)	(2,382,135)	(2,402,495)	
4	CWIP - Non Interest Bearing	685,345	685,345	685,345	685,345	685,345	685,345	685,345	685,345	685,345	685,345	685,345	685,345	685,345	
5	Net Investment (Lines 2 + 3 + 4) (A)	4,694,234	4,673,874	4,653,515	4,633,155	4,612,795	4,592,436	4,572,076	4,551,716	4,531,357	4,510,997	4,490,637	4,470,277	4,449,918	
6	Average Net Investment		4,684,054	4,663,695	4,643,335	4,622,975	4,602,615	4,582,256	4,561,896	4,541,536	4,521,177	4,500,817	4,480,457	4,460,098	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		21,645	21,551	21,457	21,363	21,269	21,175	21,081	20,986	20,892	20,798	20,704	20,610	253,531
	b Debt Component (Line 6 x Debt Component x 1/12)		5,349	5,326	5,303	5,279	5,256	5,233	5,210	5,186	5,163	5,140	5,117	5,093	62,656
8	Investment Expenses														
	a Depreciation (E)		20,360	20,360	20,360	20,360	20,360	20,360	20,360	20,360	20,360	20,360	20,360	20,360	244,316
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		47,354	47,237	47,119	47,002	46,885	46,767	46,650	46,533	46,415	46,298	46,181	46,063	560,503
	a Recoverable Costs Allocated to Energy		3,643	3,634	3,625	3,616	3,607	3,597	3,588	3,579	3,570	3,561	3,552	3,543	43,116
	b Recoverable Costs Allocated to Demand		43,711	43,603	43,495	43,386	43,278	43,170	43,061	42,953	42,845	42,737	42,628	42,520	517,387
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		3,539	3,534	3,527	3,522	3,516	3,509	3,500	3,490	3,480	3,470	3,456	3,442	41,985
13	Retail Demand-Related Recoverable Costs (I)		42,480	42,375	42,269	42,164	42,059	41,954	41,848	41,743	41,638	41,533	41,427	41,322	502,811
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		46,019	45,909	45,796	45,686	45,574	45,463	45,349	45,233	45,117	45,003	44,883	44,764	544,796

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Air Quality Compliance Program

P.E.s 0560, 0860, 1034, 1035, 1036, 1037, 1067, 1095, 1168, 1188, 1222, 1233, 1279, 1288, 1362, 1505, 1508, 1512, 1513, 1517, 1551, 1552, 1646, 1684, 1701, 1727, 1728, 1729, 1768, 1774, 1778, 1791, 1798, 1809, 1810, 1824, 1826, 1909, 1911, 1913, 1950
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
a	Expenditures/Additions		127,468	127,468	127,468	127,468	366,468	737,106	857,468	1,406,975	1,357,468	1,107,468	1,137,468	1,179,852	8,660,145
b	Clearings to Plant		4,442,256	0	0	179,337	0	130,000	0	0	0	0	480,082	7,563,152	12,794,827
c	Retirements		0	0	0	0	0	0	130,000	0	0	0	0	0	130,000
d	Cost of Removal		0	0	0	0	0	3,000	0	0	16,500	16,500	17,000	0	53,000
e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	1,347,815,790	1,352,258,046	1,352,258,046	1,352,258,046	1,352,437,383	1,352,437,383	1,352,567,383	1,352,437,383	1,352,437,383	1,352,437,383	1,352,437,383	1,352,917,464	1,360,480,617	
3	Less: Accumulated Depreciation (C)	(286,635,074)	(290,525,490)	(294,430,565)	(298,335,640)	(302,240,715)	(306,146,113)	(310,048,511)	(313,824,338)	(317,729,736)	(321,618,634)	(325,507,532)	(329,395,930)	(333,302,913)	
4	CWIP - Non Interest Bearing	10,308,217	5,993,429	6,120,897	6,248,365	6,196,496	6,562,964	7,170,070	8,027,538	9,434,513	10,791,981	11,899,449	12,556,836	6,173,535	
5	Net Investment (Lines 2 + 3 + 4) (A)	1,071,488,933	1,067,725,985	1,063,948,378	1,060,170,771	1,056,393,164	1,052,854,234	1,049,688,942	1,046,640,583	1,044,142,160	1,041,610,730	1,038,829,300	1,036,078,370	1,033,351,239	
6	Average Net Investment		1,069,607,459	1,065,837,182	1,062,059,574	1,058,281,967	1,054,623,699	1,051,271,588	1,048,164,762	1,045,391,371	1,042,876,445	1,040,220,015	1,037,453,835	1,034,714,804	
7	Return on Average Net Investment														
a	Equity Component (Line 6 x Equity Component x 1/12) (D)		4,942,656	4,925,234	4,907,777	4,890,321	4,873,416	4,857,926	4,843,569	4,830,754	4,819,132	4,806,857	4,794,074	4,781,417	58,273,133
b	Debt Component (Line 6 x Debt Component x 1/12)		1,221,492	1,217,186	1,212,872	1,208,558	1,204,380	1,200,552	1,197,004	1,193,837	1,190,965	1,187,931	1,184,772	1,181,644	14,401,194
8	Investment Expenses														
a	Depreciation (E)		3,863,371	3,878,030	3,878,030	3,878,030	3,878,353	3,878,353	3,878,782	3,878,353	3,878,353	3,878,353	3,878,353	3,879,937	46,526,299
b	Amortization (F)		27,045	27,045	27,045	27,045	27,045	27,045	27,045	27,045	27,045	27,045	27,045	27,045	324,539
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Property Taxes		547,440	547,440	547,440	547,440	547,440	547,440	547,440	547,440	547,440	547,440	547,440	547,440	6,569,285
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		10,602,004	10,594,935	10,573,165	10,551,395	10,530,635	10,511,317	10,493,841	10,477,429	10,462,935	10,447,626	10,431,685	10,417,484	126,094,451
a	Recoverable Costs Allocated to Energy		815,539	814,995	813,320	811,646	810,049	808,563	807,219	805,956	804,841	803,664	802,437	801,345	9,699,573
b	Recoverable Costs Allocated to Demand		9,786,465	9,779,940	9,759,845	9,739,749	9,720,586	9,702,754	9,686,622	9,671,473	9,658,094	9,643,963	9,629,248	9,616,139	116,394,877
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		792,386	792,652	791,442	790,688	789,617	788,696	787,396	785,805	784,355	783,150	780,711	778,396	9,445,294
13	Retail Demand-Related Recoverable Costs (I)		9,510,758	9,504,417	9,484,887	9,465,358	9,446,735	9,429,405	9,413,728	9,399,005	9,386,003	9,372,270	9,357,970	9,345,230	113,115,766
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		10,303,144	10,297,069	10,276,329	10,256,046	10,236,352	10,218,101	10,201,124	10,184,810	10,170,358	10,155,420	10,138,680	10,123,626	122,561,060

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Beginning Balances: Crist $791,000,404; Smith $229,742; Daniel $373,633,349, Scherer $182,952,295. Ending Balances: Crist $803,485,894; Smith $229,742; Daniel $373,633,349, Scherer $183,131,632.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) PE 1168 and portions of PEs 1222, 1233, 1279, 1728, 1909 and 1950 have a 7 year amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: General Water Quality
P.E.s 0831, 0861 & 1280
(in Dollars)

Line		Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1		Investments														
	a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2		Plant-in-Service/Depreciation Base (B)	832,922	832,922	832,922	832,922	832,922	832,922	832,922	832,922	832,922	832,922	832,922	832,922	832,922	
3		Less: Accumulated Depreciation (C)	(16,492)	(19,240)	(21,989)	(24,738)	(27,486)	(30,235)	(32,984)	(35,732)	(38,481)	(41,230)	(43,978)	(46,727)	(49,476)	
4		CWIP - Non Interest Bearing	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	
5		Net Investment (Lines 2 + 3 + 4) (A)	1,116,430	1,113,681	1,110,932	1,108,184	1,105,435	1,102,687	1,099,938	1,097,189	1,094,441	1,091,692	1,088,943	1,086,195	1,083,446	
6		Average Net Investment		1,115,055	1,112,307	1,109,558	1,106,809	1,104,061	1,101,312	1,098,564	1,095,815	1,093,066	1,090,318	1,087,569	1,084,820	
7		Return on Average Net Investment														
	a	Equity Component (Line 6 x Equity Component x 1/12) (D)		5,153	5,140	5,127	5,115	5,102	5,089	5,076	5,064	5,051	5,038	5,026	5,013	60,994
	b	Debt Component (Line 6 x Debt Component x 1/12)		1,273	1,270	1,267	1,264	1,261	1,258	1,255	1,251	1,248	1,245	1,242	1,239	15,074
8		Investment Expenses														
	a	Depreciation (E)		2,749	2,749	2,749	2,749	2,749	2,749	2,749	2,749	2,749	2,749	2,749	2,749	32,984
	b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9		Total System Recoverable Expenses (Lines 7 + 8)		9,175	9,159	9,143	9,127	9,111	9,096	9,080	9,064	9,048	9,032	9,016	9,000	109,051
	a	Recoverable Costs Allocated to Energy		706	705	703	702	701	700	698	697	696	695	694	692	8,389
	b	Recoverable Costs Allocated to Demand		8,469	8,454	8,440	8,425	8,410	8,396	8,381	8,367	8,352	8,337	8,323	8,308	100,662
10		Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11		Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12		Retail Energy-Related Recoverable Costs (H)		686	685	684	684	683	682	681	680	678	677	675	673	8,169
13		Retail Demand-Related Recoverable Costs (I)		8,230	8,216	8,202	8,188	8,174	8,159	8,145	8,131	8,117	8,102	8,088	8,074	97,827
14		Total Jurisdictional Recoverable Costs (Lines 12 + 13)		8,916	8,901	8,886	8,872	8,857	8,842	8,826	8,811	8,795	8,780	8,763	8,747	105,995

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) PE 1280 is fully amortized
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Coal Combustion Residuals
P.E.s 0404, 0412, 0424, 0514, 1597, 1598, 1599, 1641, 1997, 4405, 4430, 4440, 6756, 6757, 6759, 6764, 6765, CCR-C, CCR-D, CCR-S
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		6,355,785	6,630,932	7,609,577	5,480,221	4,605,497	4,425,255	2,880,461	2,909,739	2,648,579	2,424,232	2,347,619	2,447,619	50,765,515
	b Clearings to Plant		0	0	0	10,744,993	0	0	13,726,988	13,900,848	0	0	0	0	38,372,829
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	3,406,029	3,406,029	3,406,029	3,406,029	14,151,022	14,151,022	14,151,022	27,878,010	41,778,858	41,778,858	41,778,858	41,778,858	41,778,858	
3	Less: Accumulated Depreciation (C)	(37,041,296)	(37,104,517)	(37,167,738)	(37,230,959)	(37,294,181)	(37,376,743)	(37,459,305)	(37,541,868)	(37,649,138)	(37,780,041)	(37,910,943)	(38,041,845)	(38,172,747)	
4	CWIP - Non Interest Bearing	53,655,054	60,010,840	66,641,771	74,251,348	68,986,576	73,592,072	78,017,327	67,170,801	56,179,692	58,828,271	61,252,503	63,600,121	66,047,740	
5	Net Investment (Lines 2 + 3 + 4) (A)	20,019,788	26,312,352	32,880,062	40,426,418	45,843,417	50,366,352	54,709,045	57,506,944	60,309,412	62,827,089	65,120,418	67,337,135	69,653,851	
6	Average Net Investment		23,166,070	29,596,207	36,653,240	43,134,918	48,104,884	52,537,698	56,107,994	58,908,178	61,568,250	63,973,753	66,228,776	68,495,493	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		107,050	136,764	169,375	199,326	222,293	242,777	259,275	272,215	284,507	295,623	306,043	316,518	2,811,765
	b Debt Component (Line 6 x Debt Component x 1/12)		26,456	33,799	41,858	49,260	54,936	59,998	64,075	67,273	70,311	73,058	75,633	78,222	694,879
8	Investment Expenses														
	a Depreciation (E)		8,361	8,361	8,361	8,361	27,702	27,702	27,702	52,410	76,042	76,042	76,042	76,042	473,124
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		54,861	54,861	54,861	54,861	54,861	54,861	54,861	54,861	54,861	54,861	54,861	54,861	658,328
	d Property Taxes		1,199	1,199	1,199	1,199	1,199	1,199	1,199	1,199	1,199	1,199	1,199	1,199	14,383
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		197,926	234,983	275,652	313,006	360,989	386,536	407,111	447,957	486,919	500,782	513,777	526,840	4,652,479
	a Recoverable Costs Allocated to Energy		15,225	18,076	21,204	24,077	27,768	29,734	31,316	34,458	37,455	38,522	39,521	40,526	357,883
	b Recoverable Costs Allocated to Demand		182,701	216,907	254,448	288,929	333,221	356,802	375,795	413,499	449,463	462,260	474,256	486,314	4,294,596
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		14,793	17,580	20,634	23,456	27,068	29,003	30,547	33,597	36,502	37,538	38,451	39,366	348,534
13	Retail Demand-Related Recoverable Costs (I)		177,554	210,796	247,280	280,789	323,833	346,750	365,208	401,850	436,801	449,237	460,895	472,614	4,173,607
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		192,347	228,376	267,914	304,245	350,901	375,753	395,755	435,446	473,303	486,775	499,346	511,979	4,522,141

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Beginning Balances: Crist $441,896; Smith $1,404,285; Scherer $781,943; Scholz $673181; Daniel $104,724. Ending Balances: Crist $441,896; Smith $1,404,285; Scherer $25,253,924; Scholz $14,574,029; Daniel $104,724.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Steam Electric Effluent Limitations Guidelines
P.E.s 1193, 1912 & 6754
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		198,474	23,474	23,474	23,474	23,474	23,475	23,475	23,475	23,475	23,475	23,475	23,475	456,695
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	5,655,259	5,655,259	5,655,259	5,655,259	5,655,259	5,655,259	5,655,259	5,655,259	5,655,259	5,655,259	5,655,259	5,655,259	5,655,259	
3	Less: Accumulated Depreciation (C)	(185,745)	(204,408)	(223,070)	(241,732)	(260,395)	(279,057)	(297,719)	(316,382)	(335,044)	(353,706)	(372,369)	(391,031)	(409,694)	
4	CWIP - Non Interest Bearing	0	198,474	221,948	245,422	268,896	292,370	315,845	339,320	362,795	386,270	409,745	433,220	456,695	
5	Net Investment (Lines 2 + 3 + 4) (A)	5,469,514	5,649,325	5,654,137	5,658,949	5,663,760	5,668,572	5,673,384	5,678,197	5,683,010	5,687,822	5,692,635	5,697,448	5,702,260	
6	Average Net Investment		5,559,419	5,651,731	5,656,543	5,661,354	5,666,166	5,670,978	5,675,791	5,680,603	5,685,416	5,690,229	5,695,041	5,699,854	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		25,690	26,117	26,139	26,161	26,183	26,206	26,228	26,250	26,272	26,295	26,317	26,339	314,196
	b Debt Component (Line 6 x Debt Component x 1/12)		6,349	6,454	6,460	6,465	6,471	6,476	6,482	6,487	6,493	6,498	6,504	6,509	77,648
8	Investment Expenses														
	a Depreciation (E)		18,662	18,662	18,662	18,662	18,662	18,662	18,662	18,662	18,662	18,662	18,662	18,662	223,948
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		50,701	51,233	51,261	51,289	51,316	51,344	51,372	51,400	51,427	51,455	51,483	51,511	615,793
	a Recoverable Costs Allocated to Energy		3,900	3,941	3,943	3,945	3,947	3,950	3,952	3,954	3,956	3,958	3,960	3,962	47,369
	b Recoverable Costs Allocated to Demand		46,801	47,292	47,318	47,343	47,369	47,395	47,420	47,446	47,471	47,497	47,523	47,548	568,424
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		3,789	3,833	3,837	3,843	3,848	3,853	3,855	3,855	3,855	3,857	3,853	3,849	46,127
13	Retail Demand-Related Recoverable Costs (I)		45,483	45,960	45,985	46,010	46,035	46,059	46,084	46,109	46,134	46,159	46,184	46,209	552,410
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		49,272	49,793	49,822	49,853	49,882	49,912	49,939	49,964	49,989	50,016	50,037	50,058	598,537

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: 316(b) Cooling Water Intake Structure Regulation
P.E. 1691
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	100,000	100,000	0	0	50,000	400,000	950,000	125,000	125,000	125,000	25,000	2,000,000
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	2,000,000	2,000,000
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	2,000,000	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non Interest Bearing	0	0	100,000	200,000	200,000	200,000	250,000	650,000	1,600,000	1,725,000	1,850,000	1,975,000	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	0	0	100,000	200,000	200,000	200,000	250,000	650,000	1,600,000	1,725,000	1,850,000	1,975,000	2,000,000	
6	Average Net Investment		0	50,000	150,000	200,000	200,000	225,000	450,000	1,125,000	1,662,500	1,787,500	1,912,500	1,987,500	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		0	231	693	924	924	1,040	2,079	5,199	7,682	8,260	8,838	9,184	45,055
	b Debt Component (Line 6 x Debt Component x 1/12)		0	57	171	228	228	257	514	1,285	1,899	2,041	2,184	2,270	11,135
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	288	864	1,153	1,153	1,297	2,593	6,483	9,581	10,301	11,022	11,454	56,189
	a Recoverable Costs Allocated to Energy		0	22	66	89	89	100	199	499	737	792	848	881	4,322
	b Recoverable Costs Allocated to Demand		0	266	798	1,064	1,064	1,197	2,394	5,985	8,844	9,509	10,174	10,573	51,867
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		0	22	65	86	86	97	195	486	718	772	825	856	4,208
13	Retail Demand-Related Recoverable Costs (I)		0	258	775	1,034	1,034	1,163	2,326	5,816	8,595	9,241	9,887	10,275	50,406
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	280	840	1,120	1,120	1,261	2,521	6,302	9,313	10,013	10,712	11,131	54,614

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Working Capital, Mercury Allowance Expenses
For Project: Mercury Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	0	0	0	0	0	0	0	0	0	0	0	0	0	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	Average Net Working Capital Balance		0	0	0	0	0	0	0	0	0	0	0	0	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 4 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
6	Total Return Component (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Mercury Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Net Expenses (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 6 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (B)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(B) Line 9a x Line 10 x line loss multiplier
(C) Line 9b x Line 11.
(D) Line 6 is reported on Schedule 3P.
(E) Line 8 is reported on Schedule 2P.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Working Capital, Annual NOx Expenses
For Project: Annual NOx Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	7,649	7,649	7,649	7,135	6,251	5,822	5,317	4,766	4,224	3,723	2,549	1,565	435	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	7,649	7,649	7,649	7,135	6,251	5,822	5,317	4,766	4,224	3,723	2,549	1,565	435	
4	Average Net Working Capital Balance		7,649	7,649	7,392	6,693	6,036	5,569	5,042	4,495	3,974	3,136	2,057	1,000	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		35	35	34	31	28	26	23	21	18	14	10	5	280
	b Debt Component (Line 4 x Debt Component x 1/12)		9	9	8	8	7	6	6	5	5	4	2	1	69
6	Total Return Component (D)		44	44	43	39	35	32	29	26	23	18	12	6	350
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Annual NOx Allowance Expense		0	0	514	884	430	504	551	542	501	1,174	984	1,130	7,214
8	Net Expenses (E)		0	0	514	884	430	504	551	542	501	1,174	984	1,130	7,214
9	Total System Recoverable Expenses (Lines 6 + 8)		44	44	556	923	464	536	580	568	524	1,192	996	1,136	7,564
	a Recoverable Costs Allocated to Energy		3	3	517	887	432	507	553	544	503	1,175	985	1,131	7,241
	b Recoverable Costs Allocated to Demand		41	41	39	36	32	30	27	24	21	17	11	5	323
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (B)		3	3	503	864	421	494	540	530	490	1,145	958	1,098	7,051
13	Retail Demand-Related Recoverable Costs (C)		40	40	38	35	31	29	26	23	21	16	11	5	314
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		43	43	541	899	453	523	566	553	511	1,161	969	1,103	7,365

Notes:
(A) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(B) Line 9a x Line 10 x line loss multiplier
(C) Line 9b x Line 11.
(D) Line 6 is reported on Schedule 3P.
(E) Line 8 is reported on Schedule 2P.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Working Capital, Seasonal NOx Expenses
For Project: Seasonal NOx Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	9,789	9,789	9,789	9,789	9,789	8,815	6,999	5,178	2,528	1,902	1,902	1,902	1,902	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	9,789	9,789	9,789	9,789	9,789	8,815	6,999	5,178	2,528	1,902	1,902	1,902	1,902	
4	Average Net Working Capital Balance		9,789	9,789	9,789	9,789	9,302	7,907	6,089	3,853	2,215	1,902	1,902	1,902	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		45	45	45	45	43	37	28	18	10	9	9	9	343
	b Debt Component (Line 4 x Debt Component x 1/12)		11	11	11	11	11	9	7	4	3	2	2	2	85
6	Total Return Component (D)		56	56	56	56	54	46	35	22	13	11	11	11	428
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Seasonal NOx Allowance Expense		0	0	0	0	974	1,816	1,820	2,650	626	0	0	0	7,887
8	Net Expenses (E)		0	0	0	0	974	1,816	1,820	2,650	626	0	0	0	7,887
9	Total System Recoverable Expenses (Lines 6 + 8)		56	56	56	56	1,027	1,862	1,855	2,673	639	11	11	11	8,315
	a Recoverable Costs Allocated to Energy		4	4	4	4	978	1,820	1,823	2,652	627	1	1	1	7,920
	b Recoverable Costs Allocated to Demand		52	52	52	52	49	42	32	21	12	10	10	10	395
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (B)		4	4	4	4	953	1,775	1,778	2,586	611	1	1	1	7,723
13	Retail Demand-Related Recoverable Costs (C)		51	51	51	51	48	41	31	20	11	10	10	10	384
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		55	55	55	55	1,001	1,816	1,810	2,606	622	11	11	11	8,107

Notes:
(A) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(B) Line 9a x Line 10 x line loss multiplier
(C) Line 9b x Line 11.
(D) Line 6 is reported on Schedule 3P.
(E) Line 8 is reported on Schedule 2P.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Working Capital, SO2 Expenses
For Project: SO2 Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	6,299,023	6,296,667	6,294,766	6,292,872	6,290,989	6,287,546	6,282,862	6,277,818	6,272,721	6,268,501	6,265,175	6,263,266	6,261,028	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	(268)	(249)	(230)	(210)	(191)	(171)	(152)	(132)	(113)	(93)	(74)	(54)	(35)	
3	Total Working Capital Balance	6,298,755	6,296,418	6,294,537	6,292,662	6,290,799	6,287,375	6,282,711	6,277,686	6,272,608	6,268,408	6,265,101	6,263,212	6,260,993	
4	Average Net Working Capital Balance		6,297,587	6,295,477	6,293,599	6,291,730	6,289,087	6,285,043	6,280,198	6,275,147	6,270,508	6,266,755	6,264,156	6,262,102	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		29,101	29,091	29,083	29,074	29,062	29,043	29,021	28,997	28,976	28,959	28,947	28,937	348,291
	b Debt Component (Line 4 x Debt Component x 1/12)		7,192	7,189	7,187	7,185	7,182	7,178	7,172	7,166	7,161	7,157	7,154	7,151	86,074
6	Total Return Component (D)		36,293	36,281	36,270	36,259	36,244	36,221	36,193	36,164	36,137	36,115	36,100	36,089	434,365
7	Expenses														
	a Gains		(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(234)
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c SO2 Allowance Expense		2,356	1,901	1,894	1,883	3,443	4,684	5,045	5,097	4,220	3,327	1,909	2,238	37,996
8	Net Expenses (E)		2,337	1,882	1,874	1,864	3,424	4,664	5,025	5,077	4,200	3,307	1,889	2,219	37,762
9	Total System Recoverable Expenses (Lines 6 + 8)		38,630	38,163	38,144	38,123	39,668	40,885	41,218	41,241	40,337	39,422	37,990	38,307	472,127
	a Recoverable Costs Allocated to Energy		5,128	4,673	4,664	4,653	6,212	7,450	7,809	7,859	6,980	6,085	4,666	4,995	71,175
	b Recoverable Costs Allocated to Demand		33,501	33,490	33,480	33,470	33,456	33,434	33,409	33,382	33,357	33,337	33,323	33,312	400,953
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (B)		4,983	4,545	4,539	4,533	6,055	7,267	7,617	7,662	6,802	5,930	4,540	4,852	69,325
13	Retail Demand-Related Recoverable Costs (C)		32,557	32,547	32,537	32,527	32,513	32,493	32,468	32,441	32,417	32,398	32,385	32,374	389,657
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		37,540	37,091	37,075	37,060	38,569	39,760	40,085	40,104	39,220	38,328	36,925	37,226	458,982

Notes:
(A) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(B) Line 9a x Line 10 x line loss multiplier
(C) Line 9b x Line 11.
(D) Line 6 is reported on Schedule 3P.
(E) Line 8 is reported on Schedule 2P.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Working Capital, Amortization Expense
For Project: Regulatory Asset Smith Units 1 & 2
For Retired P.E.s 1413, 1440, 1441, 1442, 1444, 1454, 1459, 1460, 1461, 1462, 1468, 1469, 1647, 1620, 1638
(in Dollars)

Line		Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1		Regulatory Asset Balance 182.2 (B)	19,921,306	19,921,306	19,802,726	19,684,147	19,565,568	19,446,989	19,328,410	19,209,830	19,091,251	18,972,672	18,854,093	18,735,514	18,616,934	
2		Less Amortization (C)	0	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	
3		Net Regulatory Asset Balance (Lines 1 + 2) (A)	19,921,306	19,802,726	19,684,147	19,565,568	19,446,989	19,328,410	19,209,830	19,091,251	18,972,672	18,854,093	18,735,514	18,616,934	18,498,355	
4		Average Regulatory Asset Balance		19,862,016	19,743,437	19,624,858	19,506,278	19,387,699	19,269,120	19,150,541	19,031,962	18,913,382	18,794,803	18,676,224	18,557,645	
5		Returun on Average Regulatoy Asset Balance														
	a	Equity Component (Line 6 x Equity Component x 1/12) (D)		91,782	91,234	90,686	90,139	89,591	89,043	88,495	87,947	87,399	86,851	86,303	85,755	1,065,224
	b	Debt Component (Line 6 x Debt Component x 1/12)		22,682	22,547	22,412	22,276	22,141	22,005	21,870	21,735	21,599	21,464	21,328	21,193	263,252
6		Amortization Expense														
	a	Amortization (E)		118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	1,422,950
	b	Other (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
7		Total System Recoverable Expenses (Lines 5 + 6)		233,044	232,361	231,677	230,994	230,311	229,627	228,944	228,260	227,577	226,894	226,210	225,527	2,751,425
	a	Recoverable Costs Allocated to Energy		17,926	17,874	17,821	17,769	17,716	17,664	17,611	17,558	17,506	17,453	17,401	17,348	211,648
	b	Recoverable Costs Allocated to Demand		215,118	214,487	213,856	213,225	212,594	211,964	211,333	210,702	210,071	209,440	208,809	208,179	2,539,777
8		Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
9		Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
10		Retail Energy-Related Recoverable Costs (G)		17,418	17,384	17,342	17,310	17,269	17,230	17,179	17,119	17,060	17,008	16,930	16,851	206,100
11		Retail Demand-Related Recoverable Costs (H)		209,057	208,444	207,831	207,218	206,605	205,992	205,379	204,766	204,153	203,540	202,927	202,314	2,468,226
12		Total Jurisdictional Recoverable Costs (Lines 10 + 11)		226,475	225,828	225,173	224,528	223,874	223,222	222,558	221,885	221,213	220,548	219,857	219,165	2,674,326

Notes:
(A) End of period Regulatory Asset Balance.
(B) Beginning of period Regulatory Asset Balance.
(C) Regulatory Asset has a 15 year amortization period.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Regulatory Asset has a 15 year amortization period.
(F) Description and reason for "Other" adjustments to regulatory asset.
(G) Line 7a x Line 8 x line loss multiplier
(H) Line 7b x Line 9.

Schedule 6P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2019 - December 2019

Rate Class	(A) Average 12 CP Load Factor at Meter (%)	(B) Jan - Dec. 2019 Projected Sales at Meter (kWh)	(C) Projected Avg 12 CP at Meter (kW)	(D) Demand Loss Expansion Factor	(E) Energy Loss Expansion Factor	(F) Projected Sales at Generation (kWh)	(G) Projected Avg 12 CP at Generation (kW)	(H) Percentage of kWh Sales at Generation (%)	(I) Percentage of 12 CP Demand at Generation (%)
RS, RSVP, RSTOU	57.542346%	5,300,092,000	1,051,458	1.00609343	1.00559591	5,329,750,838	1,057,865	49.48355%	57.36917%
GS	63.463164%	299,818,000	53,930	1.00608241	1.00559477	301,495,413	54,258	2.79920%	2.94248%
GSD, GSDT, GSTOU	73.488079%	2,546,024,000	395,495	1.00590017	1.00544671	2,559,891,454	397,829	23.76706%	21.57471%
LP, LPT	82.760718%	828,364,000	114,260	0.98747379	0.99210885	821,827,255	112,828	7.63017%	6.11881%
PX, PXT, RTP, SBS	85.375300%	1,642,739,000	219,651	0.96884429	0.97666479	1,604,405,340	212,807	14.89594%	11.54077%
OS-I/II	416.652542%	104,912,000	2,874	1.00619545	1.00560119	105,499,632	2,892	0.97950%	0.15685%
OS-III	99.799021%	47,618,000	5,447	1.00617773	1.00558881	47,884,128	5,480	0.44458%	0.29721%
TOTAL		10,769,567,000	1,843,115			10,770,754,060	1,843,960	100.00000%	100.00000%

Notes:
(A) Average 12 CP load factor based on actual 2015 load research data
(B) Projected kWh sales for the period January 2019 - December 2019
(C) Calculated: (Col 2) / (8,760 x Col 1), (8,760 hours = the # of hours in 1 year)
(F) Column B x Column E
(G) Column C x Column D
(H) Column F / total for Column F
(I) Column I / total for Column I

Schedule 7P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2019 - December 2019

Rate Class	(A) Percentage of kWh Sales at Generation (%)	(B) Percentage of 12 CP Demand at Generation (%)	(C) Energy-Related Costs	(D) Demand-Related Costs	(E) Total Environmental Costs	(F) Projected Sales at Meter (kWh)	(G) Environmental Cost Recovery Factors (¢/kWh)
RS, RSVP, RSTOU	49.48355%	57.36917%	16,033,653	79,893,139	95,926,792	5,300,092,000	1.810
GS	2.79920%	2.94248%	906,996	4,097,740	5,004,736	299,818,000	1.669
GSD, GSDT, GSTOU	23.76706%	21.57471%	7,700,999	30,045,255	37,746,254	2,546,024,000	1.483
LP, LPT	7.63017%	6.11881%	2,472,327	8,521,144	10,993,471	828,364,000	1.327
PX, PXT, RTP, SBS	14.89594%	11.54077%	4,826,580	16,071,844	20,898,424	1,642,739,000	1.272
OS-I/II	0.97950%	0.15685%	317,377	218,432	535,809	104,912,000	0.511
OS-III	0.44458%	0.29721%	144,053	413,899	557,952	47,618,000	1.172
TOTAL	100.00000%	100.00000%	$32,401,985	$139,261,453	171,663,438	10,769,567,000	1.594

Notes:
(A) From Schedule 6P, Col H
(B) From Schedule 6P, Col I
(C) Column A x Total Energy $ from Schedule 1P, line 5
(D) Column B x Total Demand $ from Schedule 1P, line 5
(E) Column C + Column D
(F) Projected kWh sales for the period January 2019 - December 2019
(G) Column E x 100 / Column F

Schedule 8P
Page 1 of 1

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019

FPSC Capital Structure and Cost Rates

Line	Capital Component	(1) Jurisdictional Amount ($000s)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %	(5) Revenue Requirement Rate %	(6) Monthly Revenue Requirement Rate %
1	Bonds	826,744	34.2628	3.89	1.3328	1.3328	
2	Short-Term Debt	9,317	0.3861	4.17	0.0161	0.0161	
3	Preferred Stock	7,010	0.2905	6.14	0.0178	0.0238	
4	Common Stock	969,929	40.1968	10.25	4.1202	5.5190	
5	Customer Deposits	22,436	0.9298	2.29	0.0213	0.0213	
6	Deferred Taxes	576,770	23.9031				
7	Investment Tax Credit	741	0.0307	7.39	0.0023	0.0028	
8	Total	2,412,949	100.0000		5.5105	6.9158	0.5763
	ITC Component:						
9	Debt	826,744	45.8364	3.89	1.7830	0.0005	
10	Equity-Preferred	7,010	0.3887	6.14	0.0239	0.0000	
11	-Common	969,929	53.7749	10.25	5.5119	0.0023	
12		1,803,684	100.0000		7.3188	0.0028	
	Breakdown of Revenue Requirement Rate of Return between Debt and Equity:						
13	Total Debt Component (Lines 1, 2, 5, and 9)					1.3707	0.1142
14	Total Equity Component (Lines 3, 4, 10, and 11)					5.5451	0.4621
15	Total Revenue Requirement Rate of Return					6.9158	0.5763

Column:
(1) Based on the May 2018 Surveillance Report, Schedule 4
Adjusted to achieve the 53.5% equity ratio as prescribed in the 2018 Tax Reform Settlement Agreement in Docket No. 20180039-EI.
(2) Column (1) / Total Column (1)
(3) Based on the May 2018 Surveillance Report, Schedule 4.
(4) Column (2) x Column (3)
(5) For equity components: Column (4) / (1-.38575); 38.575% = effective income tax rate
For debt components: Column (4)
(6) Column (5) / 12

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019

For Project: Scherer - Air Quality Compliance and CCR Programs

P.E.s 1701, 1727, 1728, 1729, 1768, 1774, 1778, 1791, 1798, 6754, 6756, 6757, 6759, 6764, 6765, CCR-S
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		1,633,369	1,458,369	1,458,369	1,458,369	1,458,371	1,472,121	110,142	110,142	110,142	110,142	110,142	110,142	9,599,820
	b Clearings to Plant		0	0	0	10,924,330	0	0	13,726,988	0	0	0	0	0	24,651,318
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	16,500	16,500	17,000	0	50,000
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base	183,734,238	183,734,238	183,734,238	183,734,238	194,658,568	194,658,568	194,658,568	208,385,556	208,385,556	208,385,556	208,385,556	208,385,556	208,385,556	
3	Less: Accumulated Depreciation	(28,407,990)	(28,740,947)	(29,073,904)	(29,406,862)	(29,739,819)	(30,092,440)	(30,445,061)	(30,797,682)	(31,175,012)	(31,535,841)	(31,896,671)	(32,257,001)	(32,634,330)	
4	Working Capital (Emissions)	16,829	16,829	16,829	16,306	15,405	14,952	14,421	13,841	13,271	12,743	11,546	10,543	9,391	
5	CWIP - Non Interest Bearing	17,550,290	19,183,659	20,642,028	22,100,397	12,634,436	14,092,807	15,564,928	1,948,082	2,058,224	2,168,366	2,278,508	2,388,650	2,498,792	
6	Net Investment (Lines 2 + 3 + 4 + 5)	172,893,368	174,193,780	175,319,192	176,444,080	177,568,590	178,673,888	179,792,857	179,549,798	179,282,040	179,030,824	178,778,940	178,527,749	178,259,410	
7	Average Net Investment		173,543,574	174,756,486	175,881,636	177,006,335	178,121,239	179,233,372	179,671,327	179,415,919	179,156,432	178,904,882	178,653,345	178,393,580	
8	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12)		801,945	807,550	812,749	817,946	823,098	828,237	830,261	829,081	827,882	826,719	825,557	824,357	9,855,383
	b Debt Component (Line 6 x Debt Component x 1/12)		198,187	199,572	200,857	202,141	203,414	204,685	205,185	204,893	204,597	204,309	204,022	203,725	2,435,587
9	Investment Expenses														
	a Depreciation		329,937	329,937	329,937	329,937	349,601	349,601	349,601	374,310	374,310	374,310	374,310	374,310	4,240,101
	b Amortization		247	247	247	247	247	247	247	247	247	247	247	247	2,966
	c Dismantlement		2,773	2,773	2,773	2,773	2,773	2,773	2,773	2,773	2,773	2,773	2,773	2,773	33,273
	d Property Taxes		24,835	24,835	24,835	24,835	24,835	24,835	24,835	24,835	24,835	24,835	24,835	24,835	298,024
	e Other		0	0	0	0	0	0	0	0	0	0	0	0	0
10	O&M and Emissions														
	a O&M Expense		128,976	308,222	375,285	170,924	157,933	145,841	146,277	146,399	146,386	129,906	142,158	130,649	2,128,956
	b Emissions Expense		0	0	629	1,082	969	1,378	1,164	1,132	1,159	1,439	1,207	1,385	11,544
11	Total System Recoverable Expenses (Lines 8 + 9 + 10)		1,486,900	1,673,136	1,747,312	1,549,886	1,562,871	1,557,598	1,560,343	1,583,670	1,582,189	1,564,538	1,575,109	1,562,282	19,005,834
	a Recoverable Costs Allocated to Energy		233,328	413,069	481,174	277,860	266,751	255,575	255,990	257,775	257,766	241,442	253,349	241,927	3,436,007
	b Recoverable Costs Allocated to Demand		1,253,572	1,260,067	1,266,138	1,272,026	1,296,119	1,302,023	1,304,352	1,325,895	1,324,423	1,323,096	1,321,760	1,320,354	15,569,827
12	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
13	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
14	Retail Energy-Related Recoverable Costs		226,704	401,745	468,230	270,685	260,023	249,295	249,704	251,330	251,204	235,280	246,490	234,999	3,345,689
15	Retail Demand-Related Recoverable Costs		1,218,256	1,224,568	1,230,468	1,236,190	1,259,605	1,265,342	1,267,606	1,288,541	1,287,111	1,285,821	1,284,523	1,283,157	15,131,189
16	Total Jurisdictional Recoverable Costs (Lines 14 + 15)		1,444,960	1,626,313	1,698,698	1,506,876	1,519,628	1,514,637	1,517,310	1,539,871	1,538,316	1,521,101	1,531,013	1,518,156	18,476,878
17	Scherer/Flint Credit(24%)		346,790	390,315	407,688	361,650	364,711	363,513	364,154	369,569	369,196	365,064	367,443	364,357	4,434,451

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: **Environmental Cost**)
Recovery Clause) Docket No.: **20180007-EI**

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing was furnished by electronic mail this 24th day of August, 2018 to the following:

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